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September 27, 2024

Ms. Linda C. Bridwell, P.E.
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: *In the Matter of: Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief*-
Case No. 2024-00276

Dear Ms. Bridwell:

Please find attached Atmos Energy Corporation's Application for a general adjustment of rates using a future test period.

This is to certify that the foregoing electronic filing was transmitted to the Commission on September 27, 2024 that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and pursuant to the Commission's July 22, 2021 Order in Case No. 2020-00085, no paper copies of this filing will be made.

If you have any questions, please let me know.

Very truly yours,

L. Allyson Honaker

Enclosure

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)	**Case No. 2024-00276**

ATMOS ENERGY'S APPLICATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF

Comes now Atmos Energy Corporation ("Atmos Energy" or "the Company"), by counsel, pursuant to KRS 278.180, KRS 278.190, 807 KAR 5:001 Sections 14 and 16 and 807 KAR 5:011, and other applicable law and hereby submits its Application for a general adjustment of rates, revisions to existing tariffs, removal of existing caps on capital investment for its Pipeline Replacement Program ("PRP") and its non-PRP investment, as well as other general relief, respectfully states as follows:

I. INTRODUCTION

Atmos Energy is a foreign corporation with its headquarters in Dallas, Texas and its Kentucky office in Owensboro, Kentucky. Atmos Energy provides natural gas service to over 3.3 million residential, commercial, industrial, and public-authority customers in eight states through its six gas utility operating divisions. The gas operating divisions are located in Denver, Colorado (Colorado-Kansas Division); Baton Rouge, Louisiana (Louisiana Division); Jackson, Mississippi (Mississippi Division); Lubbock, Texas (West Texas Division); Dallas, Texas (Mid-Tex Division); and Franklin, Tennessee (Kentucky/Mid-States

Division). Atmos Energy provides service to approximately 180,694 customers throughout its service area extending from western to central Kentucky. Atmos Energy's customers are made up of residential, commercial, and industrial customers. Residential class customers account for the majority of meters of approximately 160,460. Atmos Energy's natural gas deliveries totaled approximately 49.3 Bcf during the 12-month period ending June 2024.

2. Atmos Energy is a utility as defined by KRS 278.010(3)(b) and is subject to the jurisdiction of the Kentucky Public Service Commission ("Commission") pursuant to KRS 278.040.

3. The President of the Atmos Energy Kentucky/Mid-States Division is J. Kevin Dobbs. The Vice President – Rates and Regulatory Affairs for the Kentucky/Mid-States Division is Brannon Taylor. Atmos Energy's corporate office address is:

Atmos Energy Corporation
5430 LBJ Freeway
1800 Three Lincoln Centre
Dallas, TX 75240
P.O. Box 650205
Dallas, Texas 75265-0205
www.atmosenergy.com

Atmos Energy' s Kentucky/Mid-States Division office location is:

3275 Highland Pointe Dr.
Owensboro, KY 42303
(270) 685-8000 Ph.
(270) 689-2076 fax
(Brannon.Taylor@atmosenergy.com)

II. FILING REQUIREMENTS

4. Pursuant to 807 KAR 5:001, Section 14(1) Atmos Energy states that its full name is Atmos Energy Corporation. Its mailing address is 3275 Highland Pointe Drive, Owensboro, KY 42303 and its email address is brannon.taylor@atmosenergy.com. Atmos Energy's

telephone number is (270) 685-8000 and its facsimile number is (270) 689-2076.

5. Atmos Energy requests that the following be included on the service list for this proceeding:

Brannon Taylor – Brannon.Taylor@atmosenergy.com
Vice President-Rates and Regulatory Affairs for Kentucky/Mid-States Division

L. Allyson Honaker – allyson@hloky.com
Honaker Law Office, PLLC – Counsel for Atmos Energy

Brittany Hayes Koenig – brittany@hloky.com
Honaker Law Office, PLLC – Counsel for Atmos Energy

Heather S. Temple – heather@hloky.com
Honaker Law Office, PLLC - Counsel for Atmos Energy

John. N. Hughes – jnhughes@johnnhughespsc.com
Counsel for Atmos Energy

6. Pursuant to 807 KAR 5:001, Section 14(2), Atmos Energy was initially incorporated in Texas on February 6, 1981, and in Virginia on July 21, 1997. Its articles of incorporation were filed in Case No. 2021-00214. Applicant attests that it is a foreign corporation in good standing to operate in Kentucky. A certificate of good standing is included in FR 14(2) in Volume 2.

7. Pursuant to KRS 278.192(2) and 807 KAR 5:001, Section 16(1)(a), Atmos Energy's application for a general adjustment of rates is based upon a forecasted test period ending on March 31, 2026, and using a base period that is twelve-months ending December 31, 2024, including actual data for the period from January 1, 2024, through December 31, 2024 ("Base Period"). The forecasted data is from the period from April 1, 2025, through March 31, 2026 ("Test Period"). Pursuant to KRS 278.192(2), within 45 days after the end of base period, the actual results for the estimated months will be filed.

8. Pursuant to 807 KAR 5:001, Section 16(1)(b)1, the proposed rate adjustment is necessary in order to allow Atmos Energy the opportunity to recover its reasonable operating costs and to earn a reasonable return on its investment. In addition, the proposed rate increase is needed to provide sufficient revenue for Atmos Energy to maintain its facilities and provide the level of service mandated by the Commission and Atmos Energy's customers. This additional revenue is also necessary for the attraction of additional capital. The existing rates are inadequate for these purposes and thus fail to meet the fair, just and reasonable standard. The factors that are the driving reasons for the proposed rate increase are declining return on equity and inadequate revenue to continue to provide the adequate, efficient, and reasonable service required by the Commission and demanded by customers. Atmos Energy has been faced with rising inflation in nearly every aspect of its business. Atmos Energy has continued to invest capital in its system to continue to support safety, reliability and growth in its service territory. However, due to the rising construction costs, operations and maintenance costs, cost of materials, and other rising costs Atmos Energy's current rate structure is simply not able to support the continued investment. A more detailed explanation of the need for the rate adjustment is provided in the testimony filed as FR 16(7)(a), Volumes 1 and 2.

9. Pursuant to 807 KAR 5:001, Section 16(b)(2) Atmos Energy does not operate under an assumed name in Kentucky.

10. Pursuant to 807 KAR 5:001, Section 16(1)(b)3, proposed tariff sheets in a manner compliant with 807 KAR 5:011 are contained in FR 16(1)(b)3, Volume 2. Atmos Energy proposes its new rates be effective on November 1, 2024.

11. Pursuant to 807 KAR 5:001, Section 16(1)(b)4, proposed tariff changes shown by providing present and proposed tariffs in comparative form are attached as FR 16(1)(b)4, Volume 2.

12. Pursuant to 807 KAR 5:001, Section 16(1)(b)5, a statement that notice was given in compliance with 807 KAR 5:001, Section 17 is contained in FR 16(1)(b)5 in Volume 2. A copy of the actual notice is contained in FR 17(4)(a)-(j) in Volume 3.

13. Pursuant to 807 KAR 5:001 Section 16(2) Atmos Energy filed its Notice of Intent to file this rate application with the Commission on August 23, 2024. A copy of Atmos Energy's Notice of Intent was delivered via electronic mail to the Attorney General's Office of Rate Intervention ("AG") on August 23, 2024. A copy of the Notice of Intent that was filed with the Commission is contained in FR 16(2)(c) in Volume 2 along with a copy of the email that was sent to the AG.

14. Pursuant to 807 KAR 5:001, Section 16(6) and (7), Atmos Energy provides an index/table of contents of the filing requirements attached to this application, which are required for a filing for a general adjustment of rates based on a forecasted test period. For ease of reference, Atmos Energy is uploading the index/table of contents as a separate document contemporaneously with the filing of this Application.

15. Pursuant to 807 KAR Section 17, Atmos Energy has given notice of this application and a copy of this notice is attached as FR 17(4)(a)-(j) in Volume 3. Atmos Energy is providing notice of this filing to its customers and interested parties by publication in newspapers of general circulation and posting in each of Atmos Energy local offices for public inspection as well as posting on its website.

16. Pursuant to 807 KAR 5:006, Sections 4(1) and (2), Atmos Energy's Annual Reports including the 2023 report are on file with the Commission as required by 807 KAR 5:006.

17. In this Application, Atmos Energy proposes rates that will result in an overall approximate increase in the amount of $33,001,164 or 17.9% with increases of approximately

$18,397,622 or 17.9% for G-1 residential customers, $7,226,668 or 11.5% for G-1 non-residential customers, $78,371 or 7.3% for G-2 interruptible sales customers, $2,860,131 or 35.0% for T-3 interruptible transportation customers, and $4,276,976 or 46.1% for T-4 firm transportation customers. Charges from other gas revenue will increase $161,396 or 37.9%. The average monthly bill for G-1 residential customers will increase approximately $9.59 or 19.7%. The average monthly bill for G-1 non-residential customers will increase approximately $31.11 or 13.4%. The average monthly bill for G-2 interruptible sales customers will increase approximately $853.60 or 10.2%. The average monthly bill for T-3 interruptible transportation customers will increase approximately $3,601.69 or 35.2%. The average monthly bill for T-4 firm transportation customers will increase approximately $3,134.82 or 46.6%.

18. Pursuant to 807 KAR 5:001 Section 17(4)(a), (b) and (c), the actual increases by amount and percentage for each customer class are listed in the schedule contained in FR 17(4)(a)-(j) in Volume 3.

19. Pursuant to KRS 278.2205, the most recent Cost Allocation Manual ("CAM") was provided to the Commission on April 3, 2024, and is incorporated by reference into this Application. It is also attached to the Direct Testimony of Emily Wiebe at Exhibit EBW-1.

III. DESCRIPTION OF ADDITIONAL RELIEF SOUGHT

20. In addition to the adjustment of distribution rates, Atmos Energy is requesting approval to remove existing caps on capital investment.[1] The Company is requesting full relief from the caps on

[1] Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications*, May 3, 2018 Order (Ky. PSC May 3, 2018); Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates*, May 7, 2018 Order (Ky. PSC May 7, 2018); and, Case No. 2023-00231, *Electronic Application of Atmos Energy Corporation for PRP Rider Rates Beginning October 1, 2023*, October 29, 2023 Order (Ky. PSC Oct. 29, 2023).

capital investment currently in place for both its PRP mechanism and its non-PRP capital.

21. Atmos Energy is also requesting approval of its proposed Pipeline Modernization Rider ("PM Rider") tariff to enable the Company to implement and respond to governmental directives/mandates impacting Atmos Energy, including changes in regulations promulgated by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA"); specifically the new "Mega Rule" that requires Atmos Energy to replace certain transmission infrastructure to comply with the rule. The proposed PM Rider is contained in FR 16(1)(b)3 and is discussed in more detail in the Direct Testimony of T. Ryan Austin, the Direct Testimony of Joe T. Christian, and the Direct Testimony of Gregory K. Waller.

22. Atmos Energy will file a separate application to implement any adjustments to the PM Rider in response to a governmental mandate. This will allow the Commission to determine if the improvements were necessary based upon specific PHMSA regulations approved by the Commission for inclusion in the filing. Once approved, the Company will file annual adjustments to the PM Rider for Commission approval, similar to the Company's existing PRP mechanism. The Company will maintain the burden of demonstrating that its costs imposed are not currently reflected in base rates and should be recoverable. The Company will use the rate of return approved in its most recent natural gas base rate case, or in subsequent filings for the PM Rider, for purposes of calculating the return on rate base associated with these capital pipeline replacement projects necessitated by PHMSA or other governmental agencies and regulations.

23. The Company is requesting approval of the Tax Rider ("Tax Rider") to be used to capture the effects of Public Law 117-169, 136 STAT. 1818 of August 16, 2022 ("Tax Act 2022") and certain other tax-related costs that will change from the amounts included in the base revenue requirement in Case No. 2024-00276. These effects include the return on the Corporate

Alternative Minimum Tax ("CAMT") deferred tax asset ("DTA") resulting from the Tax Act 2022, and income tax credits resulting from the Tax Act 2022 included in rate base and in the base revenue requirement in Case No. 2024-00276. The proposed Tax Rider is contained in FR 16(1)(b)3 and a more detailed description of the proposed Tax Rider can be found in the Direct Testimony of Joel Multer.

24. The Company is also requesting approval of tariff revisions for the Company's PRP mechanism to allow for the replacement of Aldyl-A pipeline, an industry-identified material, following the conclusion of the Company's replacement of bare steel pipeline in its Kentucky system. A more detailed explanation of the reason for this requested revision to the PRP mechanism is found in the Direct Testimony of T. Ryan Austin.

25. Atmos Energy is also requesting an adjustment of rates to reflect the conclusion of the three-year amortization for the Excess Deferred Income Taxes ("EDIT") Regulatory Liability that was established in Case No. 2021-00214.[2]

26. In addition to the adjustment of distribution rates, Atmos Energy is proposing certain tariff proposals are as follows:

- The revision of the Rate Book Index on Sheet No. 1 to reflect the changes described below.
- Modification of the Company's PRP tariff to permit inclusion of Aldyl-A pipe on Sheet No. 38. This tariff modification would amend the PRP applicable under the Company's Rate Schedules G-1, G-2, T-3, and T-4.
- Proposal of the Pipeline Modernization Rider ("PM Rider") on Sheet Nos. 42, 42A, and 42B that will enable the Company to recover costs associated with compliance

[2] Case No. 2021-00213, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates*, May 19, 2022 Order at 27 (Ky. PSC May 19, 2022).

with certain regulations promulgated by the U.S. Department of Transportation Pipeline and Hazardous Materials Administration, as approved by the Kentucky Public Service Commission. The PM Rider tariff will be set at zero until the effective date of approval by the Commission of a PM Rider rate. This tariff modification would be applicable under the Company's Rate Schedules G-1, G-2, T-3 and T-4. Any future adjustments to the PM Rider rate would require Kentucky Public Service Commission approval.

- Proposal of the Tax Rider ("Tax Rider") on Sheet Nos. 43, 43A, 43B, 43C and 43D to be utilized to capture the effects of Public Law 117-169, 136 STAT. 1818 of August 16, 2022 ("Tax Act 2022") and certain other tax-related costs that will change from the amounts included in the base revenue requirement in Case No. 2024-00276. These effects include the return on the Corporate Alternative Minimum Tax ("CAMT") deferred tax asset ("DTA") resulting from the Tax Act 2022, and income tax credits resulting from the Tax Act 2022 included in rate base and in the base revenue requirement in Case No. 2024-00276. The Tax Rider tariff will be set at zero until the effective date of approval by the Commission of a Tax Rider rate. This tariff modification would be applicable under the Company's Rate Schedules G-1, G-2, T-3 and T-4. Any future adjustments to the Tax Rider rate would require Kentucky Public Service Commission approval.

27. Atmos Energy requests that the Commission allow the proposed rate changes to take effect without delay.

28. Atmos Energy also requests a deviation pursuant to 807 KAR 5:006(28) from any rule, regulation or other requirement that might otherwise delay or impede the review and

approval of this Application.

29. All filing requirements ("FR") of 807 KAR 5:001 are listed in the table attached to this Application which is being uploaded as a separate document for the ease of reference.

30. Atmos Energy requests the approval of the depreciation studies supported by Ned Allis, Vice President at Gannett Fleming and included herein. Atmos Energy requests the new depreciation rates associated with assets included in the studies become effective the same time new rates become effective.

31. Atmos Energy requests recovery of its rate case expense to be amortized over a period of three years.

IV. OVERVIEW OF TESTIMONY

32. Pursuant to 807 KAR 5:001 Section 16(7)(a), Atmos Energy is providing written testimony of several witnesses. The witnesses and the topics of their Direct Testimony are as follows:

- J. Kevin Dobbs, President of the Kentucky/Mid-States Division, is describing the Company's operations in Kentucky and an overview of the Company's efforts to achieve improvements to its efficiency and productivity.
- Brannon C. Taylor, Vice President of Rates and Regulatory Affairs for Atmos Energy's Kentucky/Mid-States Division, is describing the Company's recent history of its rate proceedings before this Commission. Mr. Taylor also provides an overview of the Company's customer base and market trends since its last filed rate case, as well as describing the principal factors leading the Company to file this rate application. His testimony also introduces the other witnesses who will be providing support for the requested rate increase along with presenting the rates

and various tariff changes proposed by the Company.

- Gregory K. Waller, Director of Rates and Regulatory Affairs for Atmos Energy Corporation, is presenting testimony concerning the Operating and Maintenance ("O&M") expense budgeting process used by the Company; the control and the monitoring of O&M variances by the Company; the forecasted test year budget for O&M, the Company's capital investments, depreciation expense, and taxes other than income taxes incurred directly by the Company's Kentucky operations as well as allocated to Kentucky from the Kentucky / Mid-States General Office and Shared Services Unit. Mr. Waller is also responsible for the calculation of Company's revenue deficiency and rate base.
- Joe T. Christian, Director of Rates and Regulatory Affairs for Atmos Energy Corporation, is presenting testimony concerning the Company's capital structure and cost of debt, the policy reasons for the requests for changes to the rate recovery framework for Atmos Energy included in this case, and the Company's Cash Working Capital.
- Emily Wiebe, Director of Accounting Service and Financial Reporting for Atmos Energy Corporation, is filing testimony regarding the historic books and records of the Company and the integrity of the financial information in this case. She also provides testimony concerning the Company's Cost Allocation Manual ("CAM"), which describes the methodology for shared services cost allocations. She also provides testimony regarding the Company's use and accounting of cloud computing technology.
- Thomas Troup, Sr. Rate Analyst of Atmos Energy Corporation, is filing testimony

regarding the methods used to forecast the Company's revenues and volumes as they relate to the base period and test period in this case as well as present the test period forecast of revenues and volumes.

- T. Ryan Austin, Vice President of Technical Services for the Kentucky/Mid-States Division of Atmos Energy Corporation, is filing testimony regarding the Company's capital investments in Kentucky related to system integrity, specifically safety, as well as economic development. Mr. Austin also provides support for the Company's formal request to the Commission to lift the existing caps on capital currently in place for both the Company's PRP and non-PRP capital investment. He also provides testimony in support of the proposed PM Rider and upcoming federally required infrastructure investment, in particular that required to comply with the PHMSA Mega Rule. Lastly, Mr. Austin provides support for the Company's formal request to transition the Company's existing PRP mechanism to target Aldyl-A replacement following the Company's completion of bare steel replacement.
- Dylan D'Ascendis testifies regarding the Company's cost of capital and recommends a rate of return on equity that is appropriate to be used in setting rates for Atmos Energy in this proceeding.
- Paul Raab, of Paul H. Raab Economic Consulting, presents the Company's class cost of service study.
- Joel Multer, Vice President of Tax for Atmos Energy Corporation, is filing testimony regarding the Company's Accumulated Deferred Income Tax ("ADIT") calculations. He also supports the Company's proposed Tax Rider to capture the

effects of the Tax Act 2022 and certain other tax-related costs.

- Ned Allis, Vice President at Gannett Fleming, is filing testimony supporting new depreciation rates for the Company's Kentucky/Mid-States General Office and the Shared Services Unit.

V. CONCLUSION

Based on the information provided and in compliance with all filing requirements of KRS Chapter 278 and 807 KAR 5:001, Atmos Energy requests that the Commission issue an order: (1) approving the proposed rates; (2) approving the tariff provisions described herein including the proposed PM Rider, proposed Tax Rider, and revised PRP mechanism; (3) approving the removal of the caps on PRP and non-PRP capital investment; and (4) granting all other appropriate relief to which Atmos Energy may be entitled.

Submitted by:



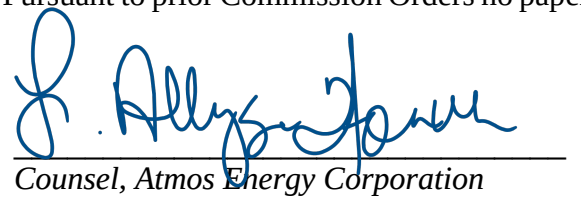
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CERTIFICATE OF SERVICE

This is to certify that the electronic filing has been transmitted to the Commission on September 27, 2024 and that there are currently no parties in this proceeding that the Commission has excused from participation by electronic means. Pursuant to prior Commission Orders no paper copies of this filing will be made.



Counsel, Atmos Energy Corporation

Law/Regulation	Filing Requirement	Witness	Volume No.
Section 16(7)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;	Allis, Austin, Dobbs, Christian, D'Ascendis, Multer, Raab, Taylor, Troup, Waller, Wiebe	1
Section 14(2)	If a corporation, identify the state that applicant is incorporated, attest that it is currently in good standing in the state it is organized and if not a Kentucky corporation attest that it is authorized to do business in Kentucky.	Taylor	2
Section 16(1)(b)1	A statement of the reason the adjustment is required.	Taylor	2
Section 16(1)(b)2	A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that such a certificate is not necessary.	Taylor	2
Section 16(1)(b)3	The proposed tariff in form complying with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.	Taylor	2
Section 16(1)(b)4	Proposed tariff changes shown either by providing present and proposed tariffs in comparative form or indicating additions by italicized inserts or underscoring and striking over deletions in a copy of the current tariff.	Taylor	2
Section 16(1)(b)5	A statement that customer notice has been given in compliance with Section 17 with a copy of the notice.	Taylor	2
Section 16(2)(a)-(c)	Notice of intent. A utility with gross annual revenues greater than $5,000,000 shall notify the commission in writing of intent to file a rate application at least thirty (30) days, but not more than sixty (60) days, prior to filing its application. (a) The notice of intent shall state if the rate application will be supported by a historical test period or a fully forecasted test period. (b) Upon filing the notice of intent, an application may be made to the commission for permission to use an abbreviated form of newspaper notice of proposed rate increases provided the notice includes a coupon that may be used to obtain a copy from the applicant of the full schedule of increases or rate changes. (c) The applicant shall also transmit by electronic mail a copy of the notice in a portable document format to the Attorney General's Office of Rate Intervention at rateintervention@ag.ky.gov.	Taylor	2
Section 16(6)(a)	Financial data for forecasted period presented as pro forma adjustments to base period.	Troup, Waller	2
Section 16(6)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	Troup, Waller	2
Section 16(6)(c)	Capitalization and net investment rate base shall be based on a 13 month average for the forecasted period.	Christian, Waller	2
Section 16(6)(d)	After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within	Taylor	2

Law/Regulation	Filing Requirement	Witness	Volume No.
	thirty (30) days of a scheduled hearing on the rate application.		
Section 16(6)(e)	The commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.	Taylor	2
Section 16(6)(f)	The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.	Waller	2
Section 16(7)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;	Allis, Austin, Dobbs, Christian, D'Ascendis, Multer, Raab, Taylor, Troup, Waller, Wiebe	1
Section 16(7)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures	Austin	2
Section 16(7)(c)	Complete description, which may be in pre-filed testimony form, of all factors used to prepare forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported;	Austin, Christian, Troup, Waller	2
Section 16(7)(d)	Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period;	Waller	2
Section 16(7)(e)	Attestation signed by utility's chief officer in charge of Kentucky operations providing: 1. That forecast is reasonable, reliable, made in good faith and that all basic assumptions used have been identified and justified; and 2. That forecast contains same assumptions and methodologies used in forecast prepared for use by management, or an identification and explanation for any differences; and 3. That productivity and efficiency gains are included in the forecast;	Dobbs	2
Section 16(7)(f)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed: 1. Date project began or estimated starting date; 2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During Construction ("AFUDC") or Interest During Construction Credit; and 4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit;	Austin	2
Section 16(7)(g)	For all construction projects constituting less than 5% of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection;	Austin	2
Section 16(7)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying		

Law/Regulation	Filing Requirement	Witness	Volume No.
	assumptions made in projecting results of operations and including the following information:		
	1. Operating income statement (exclusive of dividends per share or earnings per share);	Troup, Waller	2
	2. Balance sheet;	Waller	2
	3. Statement of cash flows;	Waller	2
	4. Revenue requirements necessary to support the forecasted rate of return;	Waller	2
	5. Load forecast including energy and demand (electric);	Not Applicable	2
	6. Access line forecast (telephone);	Not Applicable	2
	7. Mix of generation (electric);	Not Applicable	2
	8. Mix of gas supply (gas);	Troup	2
	9. Employee level;	Waller	2
	10. Labor cost changes;	Waller	2
	11. Capital structure requirements;	Christian	2
	12. Rate base;	Waller	2
	13. Gallons of water projected to be sold (water);	Not Applicable	2
	14. Customer forecast (gas, water);	Troup	2
	15. MCF sales forecasts (gas);	Troup	2
	16. Toll and access forecast of number of calls and number of minutes (telephone); and	Not Applicable	2
	17. A detailed explanation of other information provided, if applicable;	Not Applicable	2
Section 16(7)(i)	Most recent FERC or FCC audit reports;	Wiebe	2
Section 16(7)(j)	Prospectuses of most recent stock or bond offerings;	Wiebe	2
Section 16(7)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or the Automated Reporting Management Information System Report (telephone) and PSC Form T (telephone);	Wiebe	3
Section 16(7)(l)	The annual report to shareholders or members and the statistical supplements covering the most recent two (2) years from the application filing date;	Wiebe	3
Section 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts chart;	Wiebe	3
Section 16(7)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast;	Waller, Wiebe	3
Section 16(7)(o)	Complete monthly budget variance reports, with narrative explanations, for the 12 months prior to base period, each month of base period, and subsequent months, as available;	Wiebe	3
Section 16(7)(p)	SEC's annual report for most recent 2 years, Form 10-Ks and any Form 8-Ks issued during prior 2 years and any Form 10-Qs issued during past 6 quarters;	Wiebe	3
Section 16(7)(q)	Independent auditor's annual opinion report, with any written communication which indicates the existence of a material weakness in internal controls;	Wiebe	3
Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters;	Wiebe	3
Section 16(7)(s)	Summary of latest depreciation study with schedules itemized by major plant accounts, except that telecommunications utilities adopting PSC's average depreciation rates shall identify current and base period	Allis	3

Law/Regulation	Filing Requirement	Witness	Volume No.
	depreciation rates used by major plant accounts. If information has been filed in another PSC case, refer to that case's number and style;		
Section 16(7)(t)	List all commercial or in-house computer software, programs, and models used to develop schedules and work papers associated with application. Include each software, program, or model; its use; identify the supplier of each; briefly describe software, program, or model; specifications for computer hardware and operating system required to run program	Waller	3
Section 16(7)(u)	If the utility had any amounts charged or allocated to it by an affiliate or general or home office or paid any monies to an affiliate or general or home office during the base period or during the previous three (3) calendar years, the utility shall file: 1. Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment; 2. Method and amounts allocated during base period and method and estimated amounts to be allocated during forecasted test period; 3. Explain how allocator for both base and forecasted test period was determined; and 4. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable.	Waller, Wiebe	3
Section 16(7)(v)	If gas, electric or water utility with annual gross revenues greater than $5,000,000, cost of service study based on methodology generally accepted in industry and based on current and reliable data from single time period;	Raab	3
Section 16(7)(w)	Incumbent local exchange carriers with fewer than 50,000 access lines shall not be required to file cost of service studies, except as specifically directed by the commission. Local exchange carriers with more than 50,000 access lines shall file: 1. A jurisdictional separations study consistent with 47 C.F.R. Part 36; and 2. Service specific cost studies to support the pricing of all services that generate annual revenue greater than $1,000,000 except local exchange access: a. Based on current and reliable data from a single time period; and b. Using generally recognized fully allocated, embedded, or incremental cost principles.	Not Applicable	3
Section 16(8)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase;	Waller	3
Section 16(8)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of the rate base;	Multer, Waller	3

Law/Regulation	Filing Requirement	Witness	Volume No.
Section 16(8)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and by individual account;	Troup, Waller	3
Section 16(8)(d)	Summary of jurisdictional adjustments to operating income by major account with supporting schedules for individual adjustments and jurisdictional factors;	Troup, Waller	3
Section 16(8)(e)	Jurisdictional federal and state income tax summary for both base and forecasted periods with all supporting schedules of the various components of jurisdictional income taxes;	Multer, Waller	3
Section 16(8)(f)	Summary schedules for both base and forecasted periods (utility may also provide summary segregating items it proposes to recover in rates) of organization membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases;	Waller	3
Section 16(8)(g)	Analyses of payroll costs including schedules for wages and salaries, employees benefits, payroll taxes straight time and overtime hours, and executive compensation by title;	Waller	3
Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period;	Waller	3
Section 16(8)(i)	Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for 5 calendar years prior to application filing date, base period, forecasted period, and 2 calendar years beyond forecast period;	Troup, Waller, Wiebe	3
Section 16(8)(j)	Cost of capital summary for both base and forecasted periods with supporting schedules providing details on each component of the capital structure	Christian	3
Section 16(8)(k)	Comparative financial data and earnings measures for the 10 most recent calendar years, base period, and forecast period;	Troup, Waller, Wiebe	3
Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes;	Taylor	3
Section 16(8)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes; and	Troup	3
Section 16(8)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Taylor	3
Section 16(10)	A request for waiver of provisions of these filing requirements shall establish the specific reasons for the request. The commission shall grant the request for waiver upon good cause shown by the utility. In determining if good cause has been shown, the commission shall consider: (a) If other information that the utility would provide if the waiver is granted is sufficient to allow the commission to effectively and efficiently review the rate application; (b) If the information that is the subject of the waiver request is normally maintained by the utility or	Taylor	3

Law/Regulation	Filing Requirement	Witness	Volume No.
	reasonably available to it from the information that it maintains; and (c) The expense to the utility in providing the information that is the subject of the waiver request.		
Section 17(1)(a)-(c)	Notice of General Rate Adjustment. Upon filing an application for a general rate adjustment, a utility shall provide notice as established in this section. (1) Public postings. (a) A utility shall post a sample copy of the required notification at its place of business no later than the date on which the application is filed. (b) A utility that maintains a public web site shall, within five (5) business days of filing an application, post a copy of the public notice as well as a hyperlink to its filed application on the commission's Web site. (c) The information required in paragraphs (a) and (b) of this subsection shall not be removed until the commission issues a final decision on the application.	Taylor	3
Section 17(2)(b)(3)	Publish notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made by the date the application is filed.	Taylor	3
Section 17(3)(b)	If the notice is published, an affidavit from the publisher verifying the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the commission no later than forty-five (45) days of the filed date of the application.	Taylor	3
Section 17(4)(a)-(j)	Notice Requirements. Each notice shall contain the following information: (a) The proposed effective date and the date the proposed rates are expected to be filed with the Commission; (b) The present rates and proposed rates for each customer class to which the proposed rates will apply; (c) The amount of the change requested in both dollar amounts and percentage change for customer classification to which the proposed rate change will apply; (d) The amount of the average usage and the effect upon the average bill for each customer class to which the proposed rate change will apply, except for local exchange companies, which shall include the effect upon the average bill for each customer class for the proposed rate change in basic local service; (e) A statement that a person may examine this application at the office of (utility name) located at (utility address); (f) A statement that a person may examine this application at the commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov; (g) A statement that comments regarding this application may be submitted to the Public Service Commission through its Web site or my mail to Public Service	Taylor	3

Law/Regulation	Filing Requirement	Witness	Volume No.
	Commission, Post Office Box 615, Frankfort, Kentucky 40602; (h) A statement that the rates contained in this notice are the rates proposed by (name of utility) but that the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (i) A statement that a person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party; and (j) A statement that if the commission does not receive a written request for intervention within thirty (30) days of the initial publication or mailing of the notice, the commission may take final action on the application.		

State of Tennessee

County of Williamson

VERIFICATION

I, Brannon Taylor, after being duly sworn, state that I am Vice President of Rates & Regulatory Affairs of Kentucky/Mid-States, a division of Atmos Energy Corporation and that I am authorized to submit this application on behalf of the Company and that the information and statements contained in the Application are true of my own knowledge except as to those matters stated on information and belief, and as to those matters I believe them to be true.

Brannon Taylor

SUBSCRIBED, ACKNOWLEDGED AND SWORN to before me by Brannon Taylor, Vice President Rates & Regulatory Affairs on this the 20th day of September, 2024.

Pamela Pleasant
Notary Public

My Commission expires: January 24, 2028

PAMELA PLEASANT
STATE OF TENNESSEE
NOTARY PUBLIC
DAVIDSON COUNTY, TENN.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

TESTIMONY OF J. KEVIN DOBBS

INDEX TO THE DIRECT TESTIMONY
OF J. KEVIN DOBBS, WITNESS FOR
ATMOS ENERGY CORPORATION

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is J. Kevin Dobbs. I am President of the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos Energy" or the "Company"). My business address is 810 Crescent Centre Dr. Ste 600, Franklin, Tennessee, 37067.

Q. PLEASE BRIEFLY DESCRIBE YOUR CURRENT RESPONSIBILITIES, AND PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I was named President of Atmos Energy Kentucky/Mid-States Division in April 2017. In this role I am responsible for all activities in Kentucky Mid/States, which includes the operations in Kentucky, Tennessee, and Virginia. Previously, I served for ten years as vice president of operations for the Northern Region of the Kentucky/Mid-States Division. I began my career with Atmos Energy in 1985 first as an apprentice then later as supervisor and operations manager for the Company's operations in Kentucky. I have a bachelor's degree in Biology and Biophysics from Western Kentucky University.

Q. HAVE YOU SUBMITTED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. No, I have not submitted testimony before the Commission.

Q. ARE YOU SPONSORING ANY OF THE FILING REQUIREMENTS IN THIS CASE, AND, IF SO, WHICH REQUIREMENTS?

A. Yes. I am sponsoring the following filing requirements:

FR 16(7)(a) Testimony of Officer in Charge of Kentucky Operations

FR 16(7)(e) Statement of Attestation

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. No.

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND MAKE THEM PART OF YOUR TESTIMONY?

A. Yes. I adopt the filing requirements and make them a part of my testimony.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My direct testimony will briefly describe the Company's operations in Kentucky and will address the Company's efforts to achieve improvements to its efficiency and productivity.

III. ATMOS ENERGY'S OPERATIONS IN KENTUCKY

Q. CAN YOU PROVIDE THE COMMISSION WITH A GENERAL DESCRIPTION AND BACKGROUND OF THE COMPANY'S OPERATIONS IN KENTUCKY?

A. Yes. Any description of our operations begins with our vision to be the safest provider of natural gas services. Our journey in Kentucky continues to be guided

by Atmos Energy's culture – "AtmoSpirit" – and its five principles: Inspire Trust, Be at Your Best, Bring Out the Best in Others, Make a Difference, and Focus on the Future. They are the foundation for our enduring success as we safely and reliably provide natural gas service to more than 180,000 residential, commercial, industrial, and transportation consumers in Kentucky. We have a Kentucky-based work force of approximately 213 employees, and our utility plant in Kentucky includes over 4,400 miles of transmission and distribution lines.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF ATMOS ENERGY'S CORPORATE STRUCTURE AND HOW IT ENABLES THE COMPANY TO BE AN EFFICIENT, LOW COST PROVIDER OF NATURAL GAS.

A. Atmos Energy is the largest pure natural gas distribution company in the United States, delivering natural gas to over 3.3 million residential, commercial, industrial and public-authority customers in eight states. Atmos Energy has six gas utility operating divisions. They are located in Denver, Colorado (Colorado-Kansas Division); Baton Rouge, Louisiana (Louisiana Division); Flowood, Mississippi (Mississippi Division); Lubbock, Texas (West Texas Division); Dallas, Texas (Mid-Tex Division); and Owensboro, Kentucky and Franklin, Tennessee (Kentucky/Mid-States Division). In addition, Atmos Energy has an operating division consisting of a regulated intrastate pipeline that functions only within the state of Texas.

Atmos Energy's corporate offices are located in Dallas, Texas, and provide services such as accounting, legal, human resources, rate administration, procurement, information technology and customer service organizations. The Company also has two customer contact centers located in Amarillo and Waco, Texas. These centralized services are shared with the other Atmos Energy operating divisions in order to avoid having to staff and maintain these functions at each division level. These centralized services are the technical and administrative services that would be required by each division if it were a stand-alone company. Atmos Energy believes that this structure provides it with an efficiency advantage and enables it to be a low-cost, high-quality provider of natural gas.

IV. IMPROVEMENTS IN EFFICIENCY AND PRODUCTIVITY

Q. PLEASE EXPLAIN HOW THE COMPANY WORKS TO ACHIEVE IMPROVEMENTS IN ITS EFFICIENCY AND PRODUCTIVITY.

A. As described above, Atmos Energy's vision and culture are the driving forces behind the manner in which we serve our customers, which involves continuous improvements that impact efficiency and productivity. Our approach to modernizing our infrastructure leads not only to investing in the long-term safety and reliability of our system but also to more efficient operations with state-of-the art pipeline that can lead to less maintenance and repair. For example, in Kentucky Atmos Energy has eliminated low pressure systems, which has the impact of both

eliminating the safety risks inherent in those systems and also in the operation of new intermediate pressure systems that require less maintenance activities and enhanced reliability for our customers. We also achieve efficiencies through targeted cross-training of our employees to perform multiple tasks and to diversify their skill sets, which can reduce the number of employees that would otherwise be needed in certain service areas.

In addition, since our most recent rate filing in 2021, Atmos Energy has continued to make substantial investments in technology and process improvements to provide excellent customer service. Examples of these types of improvements include:

- **SAP upgrade to S4HANA**: SAP is the market leader in Enterprise Resource Software ("ERP") and is Atmos Energy's system of record for the Customer Service Organization. It houses our customer data and is the primary interface for customer contact, including billing. Atmos Energy enhanced the SAP platform to move from ECC to S/4HANA, which modernized our customer service systems to enable automation, analytics, and long-term process innovation. Through this process, the location where we store the data and the underlying technology changed, making the system processes run much faster and more efficiently. For example, every day, Atmos Energy bills about 200,000 customers across the enterprise. The billing batch processing is now

more efficient and able to be completed in a fraction of the time, which in turn allows the Revenue Management team to have more timely access to updated data to complete their necessary tasks using that data. It also allows for more timely, effective, and efficient communications with our customers through the Customer Contact Centers and the creation of service orders in the system through Dispatch. The data analytics functions also increase the efficiency and real-time accuracy of the financial and regulatory reporting overseen by our Gas Accounting group.

- **Salesforce Field Service**: To improve our service order management, Atmos Energy Corporation is migrating from SAP's Click software to Salesforce Field Service for our dispatching operations. This upgrade lays the necessary groundwork for transitioning our field operations to a mobile-based platform using Salesforce Field Service Mobile, which is expected to be launched in Kentucky in the spring of 2025. This platform will allow our technicians to capture and input information into the service record seamlessly from both their mobile device and their laptop computers and has an improved interface that allows them ease of access to information that will assist in the performance of the tasks at hand. It also facilitates the timely and accurate submission of any necessary work orders resulting from service calls.

- **Advanced Payment Methods and Non-residential Credit Card Payments**: Atmos Energy looks for ways to provide our customers with more optionalities to receive, review, interpret, and pay their natural gas bills. Our existing e-bill options and online payment options have been further enhanced by the introduction of additional advanced payment methods for residential customers. Since the Company's last rate case, we have incorporated Google Pay, Apple Pay, Amazon Pay, PayPal Credit and PayPal to provide our customers with even more options to conveniently pay their bills. More recently, we have expanded our online and phone payment options to accept non-residential credit card payments, which was not previously available. All advanced payment methods are now available for non-residential customers except Amazon Pay, providing our commercial customers with more flexibility in how to manage their natural gas utility expenses.
- **Outgoing outage/relight text messages**: In 2021, Atmos Energy first rolled out outgoing outage notifications to inform our customers in the occasional event their service is interrupted for any reason. In 2023, we incorporated additional improvements to this system to further streamline the process and enhance the functionality.

Q. HOW HAVE IMPROVEMENTS TO EFFICIENCY AND PRODUCTIVITY IMPACTED RESIDENTIAL CUSTOMER BILLS?

A. On average, residential bills have remained steady since 2007. The Company estimates that the average monthly residential bill for 2027 to be $65. While the cost of gas is a large percentage of a residential bill, the Company has been extremely efficient in order to minimize the bill impact to customers. When compared to other utility bills, the value proposition for natural gas is excellent.

Q. HAS THE COMPANY PROVIDED ANY ADDITIONAL INFORMATION ABOUT THE VALUE OF NATURAL GAS IN THIS CASE?

A. Yes. As Mr. Brannon Taylor notes in his direct testimony Atmos Energy works hard to be as efficient as possible and of the five major LDCs and the Company currently has the lowest residential rates in total in Kentucky.[1]

V. CONCLUSION

Q. DO YOU BELIEVE ATMOS ENERGY HAS MADE IMPROVEMENTS IN EFFICENCY AND PRODUCTIVITY?

A. Yes. Atmos Energy is dedicated to continuous improvements in order to achieve efficiencies and to boost its productivity.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[1] Exhibit BCT-3 contains a comparison using September 2024 amounts showing the Company's average residential bill in comparison to other Kentucky local distribution companies.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, J. Kevin Dobbs, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

J. Kevin Dobbs

STATE OF TENNESSEE

COUNTY OF WILLIAMSON

SUBSCRIBED AND SWORN to before me by J. Kevin Dobbs on this the 24th day of September, 2024.

Pamela Pleasant

Notary Public

My Commission Expires: JANUARY 24, 2028

PAMELA PLEASANT STATE OF TENNESSEE NOTARY PUBLIC DAVIDSON COUNTY, TENN.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

TESTIMONY OF BRANNON C. TAYLOR

INDEX TO THE DIRECT TESTIMONY
OF BRANNON C. TAYLOR, WITNESS FOR
ATMOS ENERGY CORPORATION

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EXHIBITS

Exhibit BCT-1 – Summary of Revenue at Proposed Rates

Exhibit BCT-2 – Proposed Monthly Revenues

Exhibit BCT-3 - Current Residential Rate Comparison to Other Utilities

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Brannon C. Taylor. I am Vice President - Rates and Regulatory Affairs for the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos Energy" or the "Company"). My business address is 810 Crescent Centre Dr. Ste 600, Franklin, Tennessee, 37067.

Q. PLEASE BRIEFLY DESCRIBE YOUR CURRENT RESPONSIBILITIES, AND PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am responsible for all rate and regulatory matters in Kentucky, Tennessee and Virginia. I graduated from Vanderbilt University in 2009 with a degree in Political Science. I also graduated from Emory University in 2012 with a law degree and am a licensed attorney. I have been with Atmos Energy Corporation since September 2012. I have served in a variety of positions of increasing responsibility in both the Corporate Rates and Regulatory Affairs group as well as the Kentucky/Mid-States Division prior to assuming my current responsibilities in 2020.

Q. HAVE YOU SUBMITTED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes, I submitted testimony in our previous case before the Commission, Case No.

2021-00214[1].

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY ON MATTERS BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes, I have filed testimony before the Tennessee Public Utility Commission and the Virginia State Corporation Commission.

Q. ARE YOU SPONSORING ANY OF THE FILING REQUIREMENTS IN THIS CASE, AND, IF SO, WHICH REQUIREMENTS?

A. Yes. I am sponsoring the following filing requirements:

FR 16(1)(a)(2)	Application Supported by a Fully Forecasted Test Period
FR 14(2)	Certified Copy of Articles of Incorporation
FR 16(1)(b)(1)	Statement of Reasons
FR 16(1)(b)(2)	Compliance with KRS 365.015
FR 16(1)(b)(3)	Proposed Tariffs
FR 16(1)(b)(4)	Proposed Tariff Changes
FR 16(1)(b)(5)	Statement on Customer Notice
FR 16(2)(a)-(c)	Notice of Intent
FR 16(6)(d)	Forecasted Test Period Revisions Requirement
FR 16(6)(e)	Alternative Forecast

[1] *In the Matter of: Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications,* Application, Case No. 2021-00214 (Ky. P.S.C., June 30, 2021).

FR 16(8)(l)	Narrative of Proposed Tariff Changes
FR 16(8)(n)	Bill Comparison
FR 16(10)	Request for Waiver of Certain Filing Requirements
FR 17(1)(a)-(c)	Notice of General Rate Adjustment
FR 17(2)(b)3	Manner of Notification
FR 17(3)(b)	Publisher Affidavits
FR 17(4)(a)-(j)	Notice Requirements

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the following Exhibits BCT-1, BCT-2, and BCT-3 which are attached to my testimony. Exhibit BCT-1 is a summary of revenue at proposed rates. Exhibit BCT-2 provides the proposed monthly revenues. Exhibit BCT-3 is a current residential rate comparison of Atmos Energy to other Kentucky gas distribution utilities.

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND MAKE THEM PART OF YOUR TESTIMONY?

A. Yes. I adopt the filing requirements and make them a part of my testimony.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My direct testimony will address several areas. First, I will briefly describe the recent history of its rate proceedings before this Commission. Second, I will provide an overview of the Company's customer base and market trends since our previous rate case. Third, I will describe the principal factors leading the Company to file this rate application. Fourth, I will introduce the other witnesses who will be providing support for the requested rate increase. Finally, I will present the rates and various tariff changes proposed by the Company.

III. OVERVIEW OF SERVICE AREA AND CUSTOMER BASE

Q. WHAT ARE THE COMPANY'S PRIMARY OBJECTIVES IN ITS KENTUCKY OPERATIONS?

A. Our vision is to be the safest provider of natural gas services, and we are proud of our operations in the Commonwealth of Kentucky. The demand for our services is growing throughout our service territory primarily through the addition of large customers. We are modernizing our distribution system to enhance the safety, reliability, versatility, and supply diversification necessary to meet the current and growing demands of our customers. We are enhancing safety practices, such as accelerating the timeframe in which we eliminate leaks, and continuously working on plans to improve our operations to meet our obligation to provide safe and

reliable service. The Company is also very proud of its tradition as a low-cost efficient provider of natural gas service. Our distribution charges, particularly for residential customers, are the lowest among the major utilities in Kentucky and our pass-through gas costs are also among the lowest in the state.

Our objectives are to continue investing in safety, modernizing infrastructure, and supporting economic growth across our service territory, all while maintaining affordable rates for the safe delivery of this reliable energy source. To achieve these objectives, we need a regulatory framework that is supportive of investment decisions necessary to focus on the future of a safe, reliable system that has the capacity to meet the growing needs of Kentucky.

Q. PLEASE DESCRIBE THE MAKEUP OF ATMOS ENERGY'S CURRENT CUSTOMER BASE IN KENTUCKY.

A. Atmos Energy currently serves approximately 180,694 customers throughout its service area extending from western to central Kentucky. Residential class customers account for the vast majority of meters, at approximately 160,460. Atmos Energy's natural gas deliveries totaled approximately 49.9 Bcf during the 12-month period ending June 2024, with about 67% of that throughput attributable to Atmos Energy's industrial customers. These industrial customers are also the driving force behind the economic development and prosperity of our service territory, providing not only employment and tax revenues to the communities we

serve but also providing natural gas revenues that offset fixed costs that would otherwise be borne by other customer classes.

IV. PRINCIPAL FACTORS FOR THIS RATE APPLICATION

Q. WHEN DID THE COMPANY'S CURRENT RATES BECOME EFFECTIVE?

A. The Company's current base distribution rates were established by the Commission in Case No. 2021-00214 and became effective on May 20, 2022.[2]

Q. WHAT HAS CHANGED SINCE THE LAST GENERAL RATE CASE?

A. While our vision and principles remain the same, the operational landscape of natural gas utilities in general and that of Atmos Energy's Kentucky operations continues to change. As more information on potential industry operational risks and challenges becomes available, both federal and state regulators and the operators they regulate have expanded and refined the minimum safety requirements to proactively address industry risks and maintain a safe system for the present and future. At the same time, the needs of our customers continue to grow, and we must rise to meet our obligations to serve those needs. Importantly for Kentucky, we have also seen continuing interest in economic development across our service territory since our last rate case, with a number of large customer

[2] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022) Order.

additions and exciting prospects for the future. While all of this has been happening, like other industries we are also seeing the underlying costs necessary to operate our business continue to rise, particularly construction costs.

Q. WHY DID THE COMPANY FILE THIS CASE?

A. Broadly, the Company is filing this case to request a regulatory framework that supports the above-mentioned changes, particularly the continued investments that Atmos Energy will need to undertake to modernize its system. This includes not only the infrastructure modernization to enhance system safety but also the infrastructure modernization to enhance reliability, versatility, and supply diversification of the system to address additional capacity needs for a growing demand for natural gas service and evolving customer needs.

As the Commission is aware, the actual costs of the natural gas consumed by our customers are collected through a gas cost adjustment mechanism. The purpose of this case is to establish new distribution rates which exclude those pass-through gas costs and which allow the Company to recover its cost of service, including a fair and reasonable return on investment. For the past fourteen years the Company has filed annual Pipeline Replacement Program ("PRP") filings to recover investments in infrastructure replacement and this has allowed the Company to extend the period between base rate cases. The Company now seeks

to recover its capital investment since its previous rate case. In total, the Company is seeking the following in this Case:

- Recover its capital investment since its last rate case;
- Request formal approval to remove existing caps on capital investment.[3] The Company is requesting full relief from the caps on capital investment currently in place for both its Pipeline Replacement Program ("PRP") mechanism and its non-PRP capital; and
- Request formal approval of the Company's Pipeline Modernization Rider ("PM Rider") for regulations promulgated by PHMSA for investments as part of federal requirements, in particular the "Mega Rule" requirements;
- Request for formal approval of the Tax Rider ("Tax Rider") to be utilized to capture the effects of Public Law 117-169, 136 STAT. 1818 of August 16, 2022 ("Tax Act 2022") and certain other tax-related costs that will change from the amounts included in the base revenue requirement in Case No. 2024-00276; and
- Request approval of tariff revisions for the Company's PRP mechanism to allow for the replacement of Aldyl-A pipeline, an industry-identified material,

[3] Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications*, May 3, 2018 Order (Ky. PSC May 3, 2018); Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates*, May 7, 2018 Order (Ky. PSC May 7, 2018); and, Case No. 2023-00231, *Electronic Application of Atmos Energy Corporation for PRP Rider Rates Beginning October 1, 2023*, October 29, 2023 Order (Ky. PSC Oct. 29, 2023).

following the conclusion of the Company's replacement of bare steel pipeline in its Kentucky system.

Q. ARE THE DISTRIBUTION RATES CURRENTLY IN EFFECT PROVIDING SUFFICIENT REVENUES?

A. No. Although Atmos Energy continues to operate very efficiently and is proud to have the lowest distribution charges for residential customers of the major natural gas providers in Kentucky, our current rates are not sufficient to provide the opportunity to earn either the return on investment previously approved by the Commission or the return calculated as fair and reasonable based on most recent data as presented in this filing.

At current rates, the Company's calculated rate of return on rate base for the test year is only 4.12%. The decline in return is primarily due to capital investment that is not recovered through the Company's current rates and to the increased costs of doing business. Examples of capital investment that are not covered through the Company's current rates are capital investment related to system integrity, system improvements, structures, public improvements, information technology, growth, and equipment. An example of a system integrity investment would be a capital investment made to replace aging infrastructure. Examples of system improvements would be capital investment related to reinforcing our existing system either through updated odorizers and regulators to any type of capacity

enhancement needed to support reliability and growth in demand. Examples of public improvements would be capital investment related to the relocation of our existing system to accommodate a public project.

Q. WHAT RATE OF RETURN ON RATE BASE IS ATMOS ENERGY REQUESTING IN THIS RATE APPLICATION?

A. Atmos Energy is asking the Commission to approve new rate schedules that would increase revenues to provide an overall rate of return on rate base of 8.30% on the test year average rate base of $628,233,491.

Q. WHAT IS THE AMOUNT OF THE RATE INCREASE THAT ATMOS ENERGY IS SEEKING IN THIS RATE APPLICATION?

A. Atmos Energy is seeking approval to increase its rates to recover approximately $33,001,164 in additional revenues. The difference between this amount and the amount cited in Mr. Waller's testimony and on Schedule A.1 of FR 16(8)(a) is due to the rounding differences inherent in striking rates. For an average residential customer, the total bill increase would be $9.59 per month.

Q. PLEASE EXPLAIN WHETHER THE COMPANY INCORPORATED THE COMMISSION'S ORDERS IN CASE NOS. 2017-00349, 2018-00281, AND 2021-00214 IN ITS RATEMAKING ADJUSTMENTS REFLECTED IN THIS FILING.

A. Yes, the Company did consider the Commission's decisions in Case Nos. 2017-00349, 2018-00281, and 2021-00214 in the preparation of this Case. Company witnesses Mr. Gregory Waller, Mr. Joe Christian, and Mr. Joel Multer discuss the various adjustments made to align this filing with the Commission's findings and Orders in Case Nos. 2017-00349, 2018-00281, and 2021-00214 in their testimonies along with adjustments or discussion where we vary from 2021-00214. While reserving the right to propose alternative approaches in future proceedings, the Company has made those changes to simplify the regulatory review process in this Case.

V. INTRODUCTION OF WITNESSES

Q. PLEASE IDENTIFY THE OTHER WITNESSES SPONSORING TESTIMONY IN THIS PROCEEDING?

A. In addition to my testimony, Atmos Energy will present the direct testimony and exhibits of nine other witnesses:

- J. Kevin Dobbs, President of Kentucky/Mid-States Division, is describing the Company's operations in Kentucky and an overview of the Company's efforts to achieve improvements to its efficiency and productivity.
- Gregory K. Waller, Director of Rates and Regulatory Affairs for Atmos Energy Corporation is presenting testimony concerning the Operating and Maintenance ("O&M") expense budgeting process used by the Company; the control and the

monitoring of O&M variances by the Company; the forecasted test year budget for O&M, the Company's capital investments, depreciation expense, and taxes other than income taxes incurred directly by the Company's Kentucky operations as well as allocated to Kentucky from the Kentucky / Mid-States General Office and Shared Services Unit. Mr. Waller is also responsible for the calculation of Company's revenue deficiency and rate base.

- Joe T. Christian, Director of Rates and Regulatory Affairs for Atmos Energy Corporation, is presenting testimony concerning the Company's capital structure and cost of debt, the policy reasons for the requests for changes to the rate recovery framework for Atmos Energy included in this case, and the Company's Cash Working Capital.
- Emily Wiebe, Director of Accounting Services and Financial Reporting for Atmos Energy Corporation, is filing testimony regarding the historic books and records of the Company and the integrity of the financial information in this case. She also provides testimony concerning the Company's Cost Allocation Manual ("CAM"), which describes the methodology for shared services cost allocations. She also provides testimony regarding the Company's proposal for an accounting change for cloud computing technology.
- Thomas Troup, Sr. Rate Analyst of Atmos Energy Corporation, is filing testimony regarding the methods used to forecast the Company's revenues and

volumes as they relate to the base period and test period in this case as well as present the test period forecast of revenues and volumes.

- T. Ryan Austin, Vice President of Technical Services for the Kentucky/Mid-States Division of Atmos Energy Corporation, is filing testimony regarding the Company's capital investments in Kentucky related to system integrity, specifically safety, as well as economic development. Mr. Austin also provides support for the Company's formal request to the Commission to lift the existing caps on capital currently in place for both the Company's PRP and non-PRP capital investment. He also provides testimony in support of the proposed PM Rider and upcoming federally required programs on the Company's horizon, in particular the PHMSA Mega Rule. Lastly, Mr. Austin provides support for the Company's formal request to transition the Company's existing PRP mechanism to target Aldyl-A replacement following the Company's completion of bare steel replacement.
- Dylan D'Ascendis testifies regarding the Company's cost of capital and recommends a rate of return on equity that is appropriate to be used in setting rates for Atmos Energy in this proceeding.
- Paul Raab, of Paul H. Raab Economic Consulting, presents the Company's class cost of service study.

- Joel Multer, Vice President of Tax for Atmos Energy Corporation, is filing testimony regarding the Company's Accumulated Deferred Income Tax ("ADIT") calculations. He also supports the Company's proposed Tax Rider to capture the effects of the Tax Act 2022 and certain other tax-related costs.
- Ned Allis, Vice President at Gannett Fleming, is filing testimony supporting new depreciation rates for the Company's Kentucky/Mid-States General Office and the Shared Services Unit.

VI. PROPOSED RATES, RATE STRUCTURES AND TARIFF CHANGES

Q. WHAT ARE THE PRIMARY RATE DESIGN OBJECTIVES AND TARIFF PROPOSALS OF ATMOS ENERGY IN THIS CASE?

A. Atmos Energy's tariff and rate design proposals are as follows:

1. Maintain the general balance of fixed and variable elements in our distribution rates to reflect the underlying cost characteristics of our service.
2. The revision of the Rate Book Index on Sheet No. 1 to reflect the changes described below. There is no revenue impact associated with this change.
3. Modification of the Company's Pipeline Replacement Program ("PRP") tariff to permit inclusion of Aldyl-A pipe on Sheet No. 38. This tariff modification would amend the PRP applicable under the Company's Rate Schedules G-1, G-2, T-3, and T-4.
4. Proposal of the Pipeline Modernization Rider ("PM Rider") on Sheet Nos. 42, 42A, and 42B that will enable the Company to recover costs associated with

compliance with regulations promulgated by the U.S. Department of Transportation Pipeline and Hazardous Materials Administration, as approved by the Kentucky Public Service Commission.

5. Proposal of the Tax Rider ("Tax Rider") on Sheet Nos. 43, 43A, 43B, 43C and 43D to be utilized to capture the effects of Public Law 117-169, 136 STAT. 1818 of August 16, 2022 ("Tax Act 2022") and certain other tax-related costs that will change from the amounts included in the base revenue requirement in Case No. 2024-00276.

Q. HOW DID YOU DETERMINE THE MANNER IN WHICH THE REVENUE DEFICIENCY WOULD BE SPREAD TO CUSTOMER CLASSES AND TO FIXED AND VARIABLE BILLING COMPONENTS?

A. Company witness Raab sponsors a Class Cost of Service study which is required pursuant to the Minimum Filing Requirements in this Case. While Mr. Raab's analysis is utilized as one point of reference, the Company believes that it is just and reasonable for each class (commercial, public authority, industrial sales and transportation), in addition to the residential class, to bear some portion of the requested increase.

With respect to the balance of the increase to be borne between the fixed or variable components, the Company has chosen to propose an increase in the fixed

monthly charges and an increase in the variable components when compared to the currents rates.

Q. WHAT IS THE RESULTING EFFECT OF ATMOS ENERGY'S PROPOSED RATES COMPARED TO CURRENT RATES FOR THE AVERAGE RESIDENTIAL, COMMERCIAL AND TRANSPORTATION CUSTOMERS RESPECTIVELY?

A. Using the test year volumes and gas costs as the basis for comparison, the annual impact of Atmos Energy's proposed rates is as follows. The average monthly charges for a residential customer under G-1 service increases $9.59, a 19.7% increase over current rates. G-1 non-residential class customers' average monthly charges increase $31.11, a 13.4% increase over current rates. T-3 interruptible transportation average monthly charges increase $3,601.69, a 35.2% increase, while T-4 firm transportation average monthly charges increase $3,134.82, a 46.6% increase. The test year revenues at proposed rates are summarized earlier in the testimony of Company witness Thomas Troup. Please refer to Exhibit BCT-1 (in a format comparable to Exhibit TLT-2) as well as Exhibit BCT-2 which provides the proposed monthly revenues (in a format comparable to Exhibit TLT-5).

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED PIPELINE MODERNIZATION RIDER.

A. The PM Rider is proposed to enable the Company to recover costs associated with compliance with regulations promulgated by PHMSA. This proposal is primarily associated with recently enacted PHMSA rules known as the "Mega Rule." Company witness T. Ryan Austin will discuss in detail in his direct testimony the Mega Rule requirements for the Company's Kentucky operations. The proposed PM Rider is designed to operate similarly to the Company's existing Pipeline Replacement Program mechanism.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED TAX RIDER TARIFF.

A. The Tax Rider is designed to be utilized to capture the effects of Public Law 117-169, 136 STAT. 1818 of August 16, 2022 ("Tax Act 2022") and certain other tax-related costs that will change from the amounts included in the base revenue requirement in Case No. 2024-00276. These effects include the return on the Corporate Alternative Minimum Tax ("CAMT") deferred tax asset ("DTA") resulting from the Tax Act 2022, and income tax credits resulting from the Tax Act 2022 included in rate base and in the base revenue requirement in Case No. 2024-00276. The Tax Rider tariff will be set at zero until the effective date of approval by the Commission of a Tax Rider rate. This tariff modification would be applicable under the Company's Rate Schedules G-1, G-2, T-3 and T-4. Any future adjustments to the Tax Rider rate would require Kentucky Public Service

Commission approval. Company witness Joel Multer discusses the Tax Rider in detail in his testimony.

VII. CAPITAL INVESTMENT

Q. IN ADDITION TO APPROVAL OF THE CAPITAL INVESTMENT INCURRED SINCE THE LAST CASE, IS THE COMPANY MAKING ANY OTHER REQUESTS RELATED TO CAPITAL INVESTMENT IN THIS CASE?

A. Yes. The Company is requesting a regulatory framework that includes the flexibility to present to the Commission the level of capital investment needed to accomplish the objectives I describe above without the limitations or uncertainties regarding capital investment levels created by past Commission orders.

Q. PLEASE DESCRIBE THE LIMITATIONS AND UNCERTAINTIES IMPOSED BY PAST COMMISSION ORDERS.

A. In the Company's 2017 general rate case ("2017 Case"), the Commission limited Atmos Energy's annual PRP investment to $28 million and extended by two years to 2027 the timeframe by which bare steel replacement was expected to be completed.[4] In the 2018 general rate case ("2018 Case"), the Commission found that safety concerns did not warrant the accelerated replacement of all Aldyl-A pipe, and that projected capital spending on non-PRP projects should be limited to $29.26

[4] Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications* (Ky. PSC May 3, 2018), Order at 41.

million based on the 2014-2018 historical average and then follow a rolling 5-year average.[5] The Commission also stated that prioritizing individual non-PRP projects within that limit on capital spending is a task to be performed by Atmos Energy. In the 2018 Case the Commission also held that non-PRP capital spending must be consistent with the Company's Distribution Integrity Management Plan ("DIMP"), and further held that if non-PRP capital spending exceeds the 5-year rolling average that Atmos Energy should be prepared to provide supporting documentation showing how each project is consistent with its DIMP.[6] This 5-year historic rolling average methodology in essence limited the Company's non-PRP capital spend to approximately the same amount going forward as the Company had caps put in place which limited the amount of any future spend. In addition, as discussed in more detail in Company witness Ryan Austin's testimony, the DIMP limitation on non-PRP spending limits potentially necessary work that could not be justified by DIMP such as growth and economic development, system improvements, or industrial customers.

Q. HAVE THESE FINDINGS IN PAST ORDERS BEEN REVISITED IN ANY OF THE COMPANY'S MORE RECENT GENERAL RATE CASE OR PRP FILINGS?

A. The Commission did not address these limitations on capital in either the Company's previous general case, Case No. 2021-00214, or the Company's 2022

[5] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), Order at 24.
[6] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), Order at 24.

PRP filing, Case No. 2022-00222. The Company discussed these topics in detail in Case No. 2021-00214 and requested approval of its capital budget, but the final Order did not ultimately address the cap on PRP investment or the limitations from the 2018 Case regarding non-PRP investment.[7] In the Company's 2023 PRP filing, Case No. 2023-00231, the Commission stated in its order that "for the reasons discussed in previous orders, the Commission finds that Atmos's PRP investment should continue to be subject to a cap, but that it should be raised to $30 million."[8] The Commission also noted that "the cap should not prevent Atmos from making necessary safety improvements and recovering such costs through base rates, but rather, limits the accelerated recovery of certain investments through the PRP rider, in which an accelerated review process makes discovery regarding individual projects difficult."[9] Because this language does not address the limitations regarding non-PRP capital contained in the Commission's Order in the 2018 case, there is regulatory uncertainty regarding Atmos Energy's ability to present for recovery a capital budget beyond the 5-year average cited in the 2018 Case.

Q. TO YOUR KNOWLEDGE, IS THIS TYPE OF LIMITATION ON CAPITAL INVESTMENT RECOVERED THROUGH A GENERAL RATE CASE COMMON IN KENTUCKY?

A. No. To my knowledge, Atmos Energy is the only utility who has received an order

[7] *See, e.g.*, Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC Nov. 18, 2021) Rebuttal Testimony of Joe T. Christian at 35-38.
[8] Case No. 2023-00231, *Electronic Application of Atmos Energy Corporation to Establish PRP Rider Rates for the Twelve Month Period Beginning October 1, 2023* (Ky. PSC September 29, 2023), Order at 16.
[9] Case No. 2023-00231, *Electronic Application of Atmos Energy Corporation to Establish PRP Rider Rates for the Twelve Month Period Beginning October 1, 2023* (Ky. PSC September 29, 2023), Order at 16.

with limitations of this type on capital investment recovered through general rate cases. Please also see the testimony of Company witness Joe Christian regarding an overview of rate recovery of infrastructure investments in other states in which Atmos Energy operates as well as the policy reasons for the requests for changes to the rate recovery framework included in this case.

Q. DOES THE COMMISSION'S DIRECTIVE IN THE 2018 ORDER ALLOW SUFFICIENT FLEXIBILITY FOR ATMOS ENERGY'S CAPITAL BUDGET TO INCLUDE ALL NECESSARY PROJECTS FOR RELIABILITY AND ECONOMIC GROWTH?

A. No. The language in Case No. 2018-00281 limits all categories of investment outside of the bare steel projects recovered through PRP. The language in the 2018 Case, discussed further by Company witness T. Ryan Austin, creates uncertainty about non-PRP investment in general and specifically about the Company's ability to recover necessary capital investments in the system that are not related to addressing threats identified through integrity management, such projects to address growth and economic development, system reliability, or facilities necessary to serve industrial customers.

Q. PLEASE DISCUSS THE COMPANY'S SERVICE AREA AND SOME OF THE ECONOMIC DEVELOPMENT PROJECTS AND PROSPECTS.

A. The Company provides gas service to a majority of western Kentucky, as well as areas in central Kentucky including Shelbyville, Lawrenceburg, Harrodsburg, and

Lebanon. These areas have seen customer growth and continued interest in attracting critical industries for the Commonwealth, most notably electric vehicle battery manufacturing and the bourbon industry. Company witness T. Ryan Austin describes these services areas in more detail including the economic development prospects as well as the capacity constraints that the Company is experiencing in the area.

Q. DO YOU HAVE A FEW EXAMPLES OF RECENT ECONOMIC DEVELOPMENT PROJECTS THAT WILL POTENTIALLY NEED EXTENSIONS OR INCREASED GAS CAPACITY?

A. Yes. A few examples include, but are not limited to, the Envision battery plant in Bowling Green, the Ascend Battery plant in Hopkinsville, the Wild Turkey Distillery expansion in Lawrenceburg, and the Willett Distillery expansion in Springfield. These projects are all high priority for economic development and provide several benefits to Kentucky.[10] The Commission's limitations on capital investment in the 2018 Order leave uncertainties regarding whether the regulatory framework in Kentucky is supportive of this investment in needed extensions.

[10] Please see the links to the press releases for these projects by the Kentucky Cabinet for Economic Development:
https://ced.ky.gov/Newsroom/NewsPage/20221020_AscendGB#:~:text=Andy%20Beshear%20joined%20local%20officials,to%20include%20up%20to%20a;
https://ced.ky.gov/Newsroom/NewsPage/20220830_EnvisionAESCGroundbreaking;
https://ced.ky.gov/Newsroom/NewsPage/20230330_Campari;
https://ced.ky.gov/Newsroom/NewsPage/20221208_Willett

Costs are increasing each year while the five-year average of Atmos Energy's capital investment in base rates has remained the same, which means there is less room within those limitations to undertake economic development projects and address any potential capacity constraints. Company witness Austin provides more detail on these areas within his testimony.

Q. WILL THE PROPOSALS IN THIS CASE, INCLUDING REMOVAL OF THE LIMITATIONS IMPOSED ON ATMOS ENERGY REGARDING NON-PRP CAPITAL INVESTMENT IN 2018, ALLOW THE COMPANY THE FLEXIBILITY TO UNDERTAKE INVESTMENTS TO SUPPORT ECONOMIC GROWTH?

A. Yes.

Q. SHOULD THESE LIMITATIONS BE REMOVED, WILL THE COMMISSION STILL HAVE THE OPPORTUNITY TO REVIEW ALL OF THE COMPANY'S CAPITAL INVESTMENT?

A. Absolutely. The Company's capital investment will still be subject to review and approval by the Commission, as it always has been. The removal of the caps grants the Company flexibility in investing in its system from year-to-year for projects in the ordinary course of business and to be appropriately proactive. Ultimately, the Commission still has complete oversight over the prudency of the Company's capital investment. As also discussed in Company witness Austin's testimony, the

Company has submitted its detailed budget for projects through the forecasted test period to provide the Commission additional guidance on its planned investments including individual project descriptions, business needs, and corresponding regulatory requirements.

Q. WOULD THE COMPANY BE OPEN TO ANY ADDITIONAL REQUIREMENTS THE COMMISSION MAY BELIEVE IS NECESSARY?

A. Yes. The Company always welcomes and seeks the opportunity to discuss any planned capital projects with the Commission outside the context of rate applications. Should the Commission desire the Company to submit its capital projects before each fiscal year, or to meet quarterly or annually to discuss projects with Commission staff the Company is available to address any concerns or questions the Commission may have concerning future proposed capital projects.

Q. HAS THE COMPANY INCLUDED ALDYL-A PROJECTS IN THIS FILING AS PART OF ITS PROPOSED NON-PRP INVESTMENT?

A. No. Company witness T. Ryan Austin discusses the system makeup of Aldyl-A for Kentucky in his testimony. The Company views the PRP mechanism as a tool to facilitate the long-term strategic replacement of Aldyl-A as the Company completes its bare steel replacement and is seeking formal approval from the Commission in this Case for its PRP mechanism to strategically incorporate long-term Aldyl-A replacement.

Q. IS THE COMPANY ALSO REQUESTING REMOVAL OF THE CAP FOR ITS PRP RIDER?

A. Yes. The Commission's order in Case No. 2017-00349 limited the Company's bare steel investment to $28 million per year in the PRP and extended the timeline by two years.[11] The Company has endeavored to target the 2027 timeframe targeted by the Commission for bare steel removal based on the capital limits set by the Commission. Despite the recent order in Case No. 2023-00231 raising the PRP cap to $30 million, keeping in mind the rising capital costs since 2017, the Company will require additional years to complete bare steel replacement, even if the caps are removed going forward. The removal of the cap will provide the Company with the needed flexibility to continue the replacement of bare steel pipe on an appropriate timeline, while still allowing the Commission complete review and approval of all proposed projects. Company witness T. Ryan Austin discusses in more detail the needs for the removal of the PRP caps and updated PRP guidance.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL OF THE PIPELINE MODERNIZATION ("PM") RIDER.

A. The Company has included a proposed PM Rider tariff in its application. The proposed PM Rider would enable the Company to recover costs associated with compliance with regulations promulgated by the U.S. Department of Transportation

[11] Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications* (Ky. PSC May 3, 2018), Order at 41.

Pipeline and Hazardous Materials Administration, more particularly the "Mega Rule," which is described in detail in the Direct Testimony of Company witness T. Ryan Austin. All proposed investments would be subject to review and approval by the Kentucky Public Service Commission.

Q. WOULD PROJECTS AND COSTS ASSOCIATED WITH THE PM RIDER BE SUBJECT TO REVIEW AND APPROVAL BY THE COMMISSION?

A. Yes. The Commission would have the ability to review projects and costs associated with the PM Rider filings. Similar to PRP filings, the Company would provide project-level details and would work with the Commission throughout to provide all the information that is requested for a review to the Commission's satisfaction to ensure compliance with all applicable PHMSA regulations, including the Mega Rule.

Q. HAS THE COMMISSION PROVIDED GUIDANCE ON WHETHER A RIDER IS APPROPRIATE FOR DIRECTIVES ISSUED BY PHMSA SUCH AS THE MEGA RULE COMPLIANCE ACTIVITIES?

A. Yes. In the Company's most recent general rate case, Case No. 2021-00214, the Commission noted that the purpose of a rider tied to capital investment in the natural gas industry is to address specific problems such as bare steel or a section of pipe prone to issues and may be tied to specific directives issued by PHMSA.[12]

[12] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022), final Order at 60 ("[T]he purpose of a rider tied to capital investment in the natural

In addition, the Commission approved a similar Pipeline Modernization Rider recently for Duke Energy Kentucky tied to its AM7 line and required Mega Rule compliance.[13] The Company's request in this Case for a PM Rider is tied to specific PHMSA directives on specific sections of pipe as identified and discussed in further detail by Company witness T. Ryan Austin.

Q. WILL YOU PROVIDE A COMPARISON OF ATMOS ENERGY'S RESIDENTIAL RATES IN COMPARISON TO OTHER KENTUCKY LOCAL DISTRIBUTION COMPANIES ("LDCs")?

A. Yes. Exhibit BCT-3 is a comparison using September 2024 amounts showing the Company's average residential bill in comparison to other Kentucky local distribution companies. Atmos Energy works hard to operate its business safely, reliably, and efficiently, and of the five major LDCs and the Company currently has the lowest residential rates in total in Kentucky. Despite having the lowest rates of the five major LDCs the Company is the only LDC that is currently subject to a cap on capital to the Company's knowledge.

Q. IS THE COMPANY PROPOSING AN ANNUAL FORMULA RATE MECHANISM AS IT DID IN CASE NO. 2017-00349?

gas industry is address specific problems such as bare steel or a section of pipe prone to issues and may be tied to specific directives issues by PHMSA").

[13] Case No. 2021-00190, *Electronic Application of Duke Energy Kentucky, Inc. for: 10 An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs, and 3) All Other Required Approvals, Waivers, and Relief,* final Order at 22 (Ky. PSC Dec. 28, 2021)

A. No. However, the Company would like for the Commission to continue to consider the potential benefits of an annual rate review mechanism similar to the one approved by the Tennessee Public Utility Commission, which has successfully produced just and reasonable rates in an efficient manner that minimizes rate case costs to customers since its inception almost ten years ago.

Q. DO YOU BELIEVE A FORMULA RATE MECHANISM WOULD BE APPROPRIATE FOR THE COMPANY'S KENTUCKY OPERATIONS?

A. Yes. A process similar to the one utilized in Tennessee would provide for a regularly scheduled rate review that will cost less and adjust the rates each year in a more timely manner to actually achieve the result contemplated by the Commission's rate orders. The Company envisions an annual mechanism saving all parties time, money, and resources, while simultaneously promoting increased transparency and interaction between the Commission, the Company, and relevant stakeholders.

Q. ARE YOU FAMILIAR WITH THE PROVISIONS IN THE COMMISSION'S ORDER IN CASE NO. 2018-00281 RELATED TO LOBBYING EXPENSES?

A. Yes, I am. I am aware that the Commission "has historically disallowed lobbying expenses from being included in base rates, including the exclusion of certain portions of employee's salaries that were determined to be lobbying-related, as well

as the corresponding portion of the employee taxes and benefits."[14]

Q. DID ATMOS ENERGY TAKE ANY ACTION IN RESPONSE TO THIS GUIDANCE FROM THE COMMISSION?

A. Yes. Atmos Energy reviewed the definition of lobbying as defined in Ky. Rev. Stat. § 6.611(27), which states as follows:

> (a) "Lobby" means to promote, advocate, or oppose the passage, modification, defeat, or executive approval or veto of any legislation by direct communication with any member of the General Assembly, the Governor, the secretary of any cabinet listed in KRS 12.250, or any member of the staff of any of the officials listed in this paragraph.
>
> (b) "Lobbying" does not include:
>
> 1. Appearances before public meetings of the committees, subcommittees, task forces, and interim committees of the General Assembly;
>
> 2. News, editorial, and advertising statements published in newspapers, journals, or magazines, or broadcast over radio or television;
>
> 3. The gathering and furnishing of information and news by bona fide reporters, correspondents, or news bureaus to news media described in paragraph (b)2. of this subsection;
>
> 4. Publications primarily designed for, and distributed to, members of bona fide associations or charitable or fraternal nonprofit corporations;
>
> 5. Professional services in drafting bills or resolutions, preparing arguments on these bills or resolutions, or in advising clients and rendering opinions as to the construction and the effect of proposed or pending legislation, if the services are not otherwise connected with lobbying; or
>
> 6. The action of any person not engaged by an employer who has a direct interest in legislation, if the person, acting under Section 1 of the Kentucky Constitution, assembles together

[14] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), final Order at 53-54.

> with other persons for their common good, petitions any official listed in this subsection for the redress of grievances, or other proper purposes.

Atmos Energy also considered the Commission's prohibition on the inclusion of "political advertising" in rates, which is defined in KAR 5:016 as advertising intended to influence "public opinion with respect to legislative, administrative, or electoral matters, or with respect to any controversial issue of public importance." After reviewing these definitions and the Commission's Orders related to this issue, Atmos Energy determined that any such services performed on behalf of Atmos Energy are performed by external contractors and are not performed by employees of Atmos Energy's Kentucky/Mid-States division. As indicated in the direct testimony of Company witness Gregory Waller, 100% of all external lobbying activities are coded to account 4264 and excluded from recovery. Atmos Energy has included Schedule F-7 for a summary of these expenses, none of which are included for recovery in this rate case.

Q. WHAT WAS YOUR DETERMINATION AS TO WHETHER YOU OR OTHER ATMOS ENERGY EMPLOYEES IN THE KENTUCKY DIVISION ENGAGE IN LOBBYING ACTIVITIES?

A. We determined that neither I nor any other employees in the Kentucky/Mid-States division engage in lobbying activities. However, we identified three positions in the Kentucky/Mid-States division that interact as necessary on a very limited basis

with our external lobbyists to provide them with information they need to perform their duties and that occasionally attend meetings that are related to the work performed by our external contractor lobbyists or the subject matters addressed by those external lobbyists. These three positions are Vice President of Rates and Regulatory Affairs, Vice President of Public Affairs, and Manager of Public Affairs. For example, as part of my duties, I occasionally discuss various regulatory or legislative matters with other Atmos Energy employees, Atmos Energy external contractors, other utility officials, or members of the public. These discussions are infrequent and generally incidental to the specific topics being discussed. Because they are generally not scheduled or formal discussions of legislative matters and are part of other topics, time for the discussion is not tracked and would be difficult to track given their informal, spur of the moment nature and intermingling with other topics and duties. Since formal time-tracking is impossible, instead I have examined my duties and determined that such activities never exceed an average of two hours per week (or 5%) of my time. To be clear, these activities I perform do not meet the definition of "lobbying." However, because the topics discussed could be considered to be related to lobbying activities in the broadest sense, I have designated 5% of my salary each month potentially related to lobbying activities to comply with the strictest application of the term, and that amount is excluded from

recovery through rates. This assures that no part of my salary that could possibly be considered as lobbying expenses included in rates.

Q. DID THE VICE PRESIDENT OF PUBLIC AFFAIRS AND MANAGER OF PUBLIC AFFAIRS PERFORM A SIMILAR ANALYSIS OF THEIR TIME?

A. Yes. After the 2018 rate case, a similar analysis was conducted of the duties of the Vice President of Public Affairs and Manager of Public Affairs. It was concluded that neither engage in lobbying, and that any duties they may have that are even remotely related to lobbying activities amount to less than 5% of their weekly time on average. Therefore, 5% of their salary is designated each month to be potentially related to lobbying activities to comply with the strictest application of the term, and that amount is excluded from recovery through rates. This ensures that no part of their salaries that could possibly be considered as lobbying expenses included in rates.

VIII. CONCLUSION

Q. DO YOU BELIEVE THAT THE FORECASTED TEST PERIOD COST OF SERVICE COMPONENTS YOU HAVE PRESENTED REPRESENT THE MOST REASONABLE ESTIMATE OF COSTS FOR THE TEST PERIOD USED IN THIS PROCEEDING?

A. Yes. The cost of service forecast presented by the Company witnesses is the best projection of the Company's future cost of service and will allow the Company to provide service to customers in a safe and reliable manner. The Commission

granting the Company permission to remove the limitations on capital (other than the requirement that such investments be prudent) will allow it to continue the acceleration of the pace of replacement of its highest relative risk infrastructure and enable it to partner in economic development while remaining the most economic option for energy delivery to the home.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Brannon C. Taylor, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Brannon C. Taylor

STATE OF TENNESSEE

COUNTY OF WILLIAMSON

SUBSCRIBED AND SWORN to before me by Brannon C. Taylor on this the 20th day of September, 2024.

Pamela Pleasant

Notary Public

My Commission Expires: JANUARY 24, 2028

PAMELA PLEASANT
STATE OF TENNESSEE
NOTARY PUBLIC
DAVIDSON COUNTY, TENN.

ATMOS ENERGY CORPORATION – KENTUCKY
SUMMARY OF REVENUE AT PROPOSED RATES
TEST YEAR ENDING MARCH 31 2026

Line No.	Description	Block (Mcf)	Reference Period - Twelve Months Ending 06/30/2024 Number of Bills, Units	Volumes As Metered	Contract Adj. Bills and Volumes	Weather Adj. Volumes NOAA 2004–2024	Total Volumes	Forward-looking Adjustments To Test Year Customer Growth Forecast	Conservation & Efficiency Adjustments	Total Test Year Volumes	Proposed Margin	Proposed Revenue
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(i)	(j)	(k)
1	Sales											
2	Firm Sales (G-1)	Customer Chrg	1,925,523					0			$25.00	$48,138,075
3		Customer Chrg	240,271		2			1,052			75.00	18,099,375
4		0 - 300		13,848,723	506	1,982,025	15,831,254	24,087	0	15,855,342	2.2951	36,389,595
5		301 - 15,000		1,158,518	(1,109)	64,221	1,221,630	3,822	0	1,225,452	1.5953	1,954,963
6		Over 15,000		0	0	0	0		0	0	1.3175	0
7	Interruptible Sales (G-2)	Customer Chrg	105		0						685.00	71,925
8		0 - 15,000		28,778	0		28,778			28,778	1.2956	37,284
9		Over 15,000		183,933	0		183,933			183,933	1.0624	195,411
10												
11	Transportation											
12	Customer Charges (T-4)	Customer Chrg	1,434		(19)						685.00	969,380
13	Customer Charges (T-3)	Customer Chrg	844		8						685.00	583,620
14	Customer Charges (SpK)	Customer Chrg	164		(10)						520.00	80,160
15	Transp. Adm. Fee	Customer Chrg	2,423		(21)						50.00	120,100
16	Parked Volumes [1]			0	0						0.00	0
17	EFM Charges										Various	139,875
18	Firm Transportation (T-4)	0 - 300		403,618	2,867		406,485			406,485	2.2951	932,925
19		301 - 15,000		5,765,684	21,096		5,786,780			5,786,780	1.5953	9,231,650
20		Over 15,000		1,721,058	(4,252)		1,716,805			1,716,805	1.3175	2,261,891
21	Economic Dev Rider (EDR)	301 - 15,000		0	0		0			0	1.1965	0
22		Over 15,000		0	0		0			0	0.9881	0
23	Interruptible Transportation (T-3)	0 - 15,000		5,188,458	18,957		5,207,415			5,207,415	1.2956	6,746,727
24		Over 15,000		3,407,069	0		3,407,069			3,407,069	1.0624	3,619,670
25	Total Special Contracts [2]			15,175,074	330,108		15,505,182			15,505,182	Various	3,022,030
26												
27	Total Tariff		2,168,341	46,880,912	368,173	2,046,246	49,295,331	28,962	0	49,323,241		132,594,656
28												
29	Other Revenues											58,912
30	Late Payment Fees											528,858
31	Total Gross Profit											133,182,426
32												
33	Gas Costs											87,640,898
34												
35	Total Revenue											$ 220,823,324
36												
37	[1] Parked Volumes not included in Total Deliveries.											
38	[2] Based on confidential information.											

EXHIBIT BCT-2

ATMOS ENERGY CORPORATION – KENTUCKY
BILL FREQUENCY WITH KNOWN & MEASURABLE ADJUSTMENTS
TEST YEAR ENDING MARCH 31 2026
PROPOSED RATES

Line No.	Class of Customers	Rate	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Total Billing Units
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	RESIDENTIAL (Rate G-1)		$6,081,538	$5,035,683	$4,434,632	$4,324,786	$4,318,905	$4,297,833	$4,655,018	$6,076,926	$7,530,852	$8,292,518	$8,653,071	$7,246,378	$70,948,139
2	FIRM BILLS	$25.00	162,288	161,528	160,443	158,859	158,643	157,525	158,693	160,008	161,112	162,059	162,229	162,136	1,925,523
3	Sales: 1-300	2.2951	882,026	434,614	184,549	153,941	153,732	156,728	299,635	904,852	1,526,318	1,847,869	2,003,113	1,391,215	9,938,593
4	Sales: 301-15000	1.5953	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Sales: Over 15000	1.3175	0	0	0	0	0	0	0	0	0	0	0	0	0
6	CLASS TOTAL (Mcf/month)		882,026	434,614	184,549	153,941	153,732	156,728	299,635	904,852	1,526,318	1,847,869	2,003,113	1,391,215	9,938,593
7	Gas Charge per Mcf		$4.58	$4.93	$4.93	$4.93	$5.30	$5.30	$5.30	$5.33	$5.33	$5.33	$4.89	$4.89	
8	Gas Costs		$4,040,819	$2,144,025	$910,409	$759,418	$814,618	$830,496	$1,587,751	$4,822,698	$8,134,995	$9,848,803	$9,800,500	$6,806,706	$50,501,238
9															
10	FIRM COMMERCIAL (Rate G-1)		$2,523,402	$2,027,425	$1,734,863	$1,674,757	$1,672,899	$1,650,085	$1,795,550	$2,478,596	$3,147,650	$3,491,368	$3,656,810	$3,051,274	$28,904,678
11	FIRM BILLS	75.00	18,884	18,586	18,217	17,906	17,852	17,731	17,935	18,360	18,636	18,899	18,881	18,894	220,781
12	Sales: 1-300	2.2951	450,438	256,777	147,123	130,646	134,814	113,316	149,215	437,071	697,238	802,225	879,857	660,856	4,859,577
13	Sales: 301-15000	1.5953	45,948	27,672	19,386	20,034	15,412	37,728	67,675	61,727	93,850	145,901	138,767	73,650	747,751
14	Sales: Over 15000	1.3175	0	0	0	0	0	0	0	0	0	0	0	0	0
15	CLASS TOTAL (Mcf/month)		496,386	284,449	166,509	150,680	150,226	151,044	216,890	498,799	791,088	948,126	1,018,624	734,506	5,607,328
16	Gas Charge per Mcf		$4.58	$4.93	$4.93	$4.93	$5.30	$5.30	$5.30	$5.33	$5.33	$5.33	$4.89	$4.89	
17	Gas Costs		$2,274,090	$1,403,237	$821,416	$743,332	$796,040	$800,376	$1,149,288	$2,658,506	$4,216,356	$5,053,340	$4,983,754	$3,593,667	$28,493,403
18															
19	FIRM INDUSTRIAL (Rate G-1)		$112,145	$113,143	$51,351	$46,471	$56,663	$53,629	$60,777	$101,623	$155,078	$241,098	$226,892	$148,720	$1,367,589
20	FIRM BILLS	$75.00	213	212	210	203	215	208	210	213	208	205	212	215	2,524
21	Sales: 1-300	2.2951	27,358	16,430	9,573	8,454	8,648	9,243	10,823	23,510	34,113	43,948	45,008	34,440	271,549
22	Sales: 301-15000	1.5953	20,925	37,319	8,543	7,424	12,968	10,541	12,654	19,864	38,354	78,266	67,506	33,568	347,933
23	Sales: Over 15000	1.3175	0	0	0	0	0	0	0	0	0	0	0	0	0
24	CLASS TOTAL (Mcf/month)		48,282	53,749	18,117	15,878	21,617	19,784	23,477	43,374	72,466	122,214	112,515	68,009	619,482
25	Gas Charge per Mcf		$4.58	$4.93	$4.93	$4.93	$5.30	$5.30	$5.30	$5.33	$5.33	$5.33	$4.89	$4.89	
26	Gas Costs		$221,196	$265,152	$89,373	$78,327	$114,547	$104,833	$124,403	$231,178	$386,232	$651,380	$550,494	$332,741	$3,149,856
27															
28	FIRM PUBLIC AUTHORITY (Rate G-1)		$291,236	$214,470	$168,787	$165,157	$165,524	$167,872	$192,025	$295,875	$401,677	$449,470	$471,742	$377,616	$3,361,453
29	FIRM BILLS	$75.00	1,504	1,513	1,483	1,490	1,493	1,496	1,504	1,502	1,507	1,516	1,503	1,507	18,018
30	Sales: 1-300	2.2951	72,573	39,287	22,476	21,359	21,453	23,643	31,614	73,414	114,686	124,978	134,401	105,739	785,623
31	Sales: 301-15000	1.5953	7,443	6,787	3,748	2,749	2,703	883	4,180	9,235	15,945	30,673	31,689	13,734	129,768
32	Sales: Over 15000	1.3175	0	0	0	0	0	0	0	0	0	0	0	0	0
33	CLASS TOTAL (Mcf/month)		80,016	46,074	26,223	24,109	24,156	24,526	35,794	82,649	130,630	155,651	166,090	119,473	915,391
34	Gas Charge per Mcf		$4.58	$4.93	$4.93	$4.93	$5.30	$5.30	$5.30	$5.33	$5.33	$5.33	$4.89	$4.89	
35	Gas Costs		$366,577	$227,292	$129,363	$118,931	$128,002	$129,963	$189,670	$440,503	$696,237	$829,592	$812,617	$584,536	$4,653,284
36															
37	INTERRUPTIBLE COMMERCIAL (G-2)		$2,759	$3,255	$1,447	$1,395	$1,407	$1,529	$1,427	$2,275	$3,312	$3,983	$4,475	$3,479	$30,744
38	INT BILLS	685.00	3	4	2	2	2	2	2	3	3	3	3	3	32
39	Sales: 1-15000	1.2956	543	398	59	19	29	122	44	170	970	1,488	1,868	1,099	6,812
40	Sales: Over 15000	1.0624	0	0	0	0	0	0	0	0	0	0	0	0	1
41	CLASS TOTAL (Mcf/month)		543	398	59	19	29	122	44	170	970	1,488	1,868	1,099	6,813
42	Gas Charge per Mcf		$3.48	$3.83	$3.83	$3.83	$4.20	$4.20	$4.20	$4.23	$4.23	$4.23	$3.79	$3.79	
43	Gas Costs		$1,891	$1,524	$227	$73	$120	$514	$186	$719	$4,105	$6,295	$7,086	$4,169	$26,911
44															

EXHIBIT BCT-2

ATMOS ENERGY CORPORATION – KENTUCKY
BILL FREQUENCY WITH KNOWN & MEASURABLE ADJUSTMENTS
TEST YEAR ENDING MARCH 31 2026
PROPOSED RATES

Line No.	Class of Customers	Rate	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Total Billing Units
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
45	INTERRUPTIBLE INDUSTRIAL (G-2)		$28,290	$24,412	$23,608	$13,276	$14,628	$18,182	$16,775	$21,414	$27,571	$29,257	$26,534	$29,930	$273,877
46	INT BILLS	685.00	6	6	6	5	5	6	6	6	5	8	8	6	73
47	Sales: 1-15000	1.2956	2,078	2,200	1,286	1,621	2,041	2,038	1,557	1,833	1,436	1,910	1,861	2,105	21,969
48	Sales: Over 15000	1.0624	20,225	16,426	16,784	7,296	8,056	10,760	10,023	14,052	20,977	20,051	17,548	21,736	183,934
49	CLASS TOTAL (Mcf/month)		22,304	18,627	18,070	8,916	10,097	12,798	11,580	15,885	22,413	21,961	19,409	23,841	205,903
50	Gas Charge per Mcf		$3.48	$3.83	$3.83	$3.83	$4.20	$4.20	$4.20	$4.23	$4.23	$4.23	$3.79	$3.79	
51	Gas Costs		$77,646	$71,399	$69,266	$34,178	$42,397	$53,737	$48,623	$67,191	$94,802	$92,892	$73,630	$90,445	$816,206
52															
53	TRANSPORTATION (T-4)		$972,218	$957,239	$980,857	$954,813	$1,114,175	$1,214,521	$1,260,925	$1,538,076	$1,281,252	$1,208,353	$1,064,573	$1,003,070	$13,550,070
54	TRANSPORTATION BILLS	685.00	118	118	118	117	117	117	117	117	118	118	118	118	1,415
55	Trans Admin Fee		5,900	5,900	5,900	5,850	5,850	5,850	5,850	5,850	5,900	5,900	5,900	5,950	$70,600
56	EFM Fee		7,050	7,050	7,125	6,750	6,900	6,750	6,900	6,900	6,975	7,050	7,200	6,975	$83,625
57	Parking Fee		0	0	0	0	0	0	0	0	0	0	0	0	$0
58	Firm Transport: 1-300	2.2951	31,741	31,401	31,573	31,784	34,535	36,152	36,243	35,897	35,222	35,441	34,241	32,256	406,485
59	Firm Transport: 301-15000	1.5953	412,964	406,841	413,845	404,807	471,920	525,332	567,791	676,762	551,047	503,579	440,323	411,568	5,786,780
60	Firm Transport: Over 1500	1.3175	111,234	107,871	116,961	108,610	143,399	152,185	135,722	214,738	172,590	174,297	143,735	135,463	1,716,805
61	CLASS TOTAL (Mcf/month)		555,939	546,113	562,378	545,201	649,854	713,669	739,756	927,398	758,859	713,316	618,299	579,287	7,910,070
62															
63	ECONOMIC DEV RIDER (EDR)		-	-	-	-	-	-	-	-	-	-	-	-	-
64	Firm Transport: 1-300	1.7213	0	0	0	0	0	0	0	0	0	0	0	0	0
65	Firm Transport: 301-15000	1.1965	0	0	0	0	0	0	0	0	0	0	0	0	0
66	Firm Transport: Over 15000	0.9881	0	0	0	0	0	0	0	0	0	0	0	0	0
67	CLASS TOTAL (Mcf/month)		0	0	0	0	0	0	0	0	0	0	0	0	0
68															
69	TRANSPORTATION (T-3)		$885,939	$837,473	$744,530	$836,997	$964,344	$989,195	$993,460	$1,064,842	$963,084	$961,608	$903,437	$894,808	$11,039,716
70	TRANSPORTATION BILLS	685.00	71	71	71	71	71	71	71	71	71	71	71	71	852
71	Trans Admin Fee		3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	$42,000
72	EFM Fee		3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	$47,700
73	Parking Fee		0	0	0	0	0	0	0	0	0	0	0	0	$0
74	Interrupt Transport: 1-15000	1.2956	417,295	401,974	388,998	399,640	444,352	465,475	465,884	488,045	447,165	436,683	426,391	425,512	5,207,416
75	Interrupt Transport: Over 15000	1.0624	272,196	245,261	173,601	247,659	313,001	310,633	314,148	354,311	308,384	319,776	277,574	270,524	3,407,070
76	CLASS TOTAL (Mcf/month)		689,492	647,235	562,599	647,299	757,353	776,107	780,032	842,356	755,549	756,460	703,965	696,036	8,614,486
77															
78	SPECIAL CONTRACTS		$294,857	$274,116	$255,651	$224,506	$270,434	$240,831	$215,894	$256,669	$240,852	$258,976	$304,934	$280,519	$3,118,240
79	TRANSPORTATION BILLS	520.00	13	13	13	12	12	12	12	12	12	13	13	13	154
80	Trans Admin Fee		650	650	650	600	600	600	600	600	600	650	650	650	$7,500
81	EFM Fee		750	750	750	675	675	675	675	675	675	750	750	750	$8,550
82	Parking Fee		0	0	0	0	0	0	0	0	0	0	0	0	$0
83	Transported Volumes	Various	1,174,025	1,325,397	1,227,574	1,095,712	1,171,326	1,223,327	1,296,950	1,535,324	1,391,760	1,467,401	1,320,464	1,275,923	15,505,182
84	Charges for Transport Volumes		286,517	265,776	247,311	216,811	262,739	233,136	208,199	248,974	233,157	250,636	296,594	272,179	$3,022,030
85	CLASS TOTAL (Mcf/month)		1,174,025	1,325,397	1,227,574	1,095,712	1,171,326	1,223,327	1,296,950	1,535,324	1,391,760	1,467,401	1,320,464	1,275,923	15,505,182
86															
87	OTHER REVENUE														
88	Service Charges		$3,438	$3,844	$3,004	$3,387	$3,698	$4,212	$9,928	$8,550	$4,906	$5,587	$4,026	$4,332	$58,912
89	Late Payment Fees		$55,084	$41,251	$30,537	$24,484	$23,615	$23,934	$24,930	$32,775	$51,818	$68,896	$77,833	$73,702	$528,858
90															
91	TOTAL GROSS PROFIT		$11,250,905	$9,532,312	$8,429,267	$8,270,028	$8,606,293	$8,661,821	$9,226,709	$11,877,620	$13,808,053	$15,011,114	$15,394,326	$13,113,827	$133,182,275
92	Gas Costs		$6,982,219	$4,112,630	$2,020,054	$1,734,260	$1,895,724	$1,919,919	$3,099,922	$8,220,795	$13,532,728	$16,482,302	$16,228,082	$11,412,264	$87,640,898
93	TOTAL REVENUE		$18,233,124	$13,644,941	$10,449,321	$10,004,288	$10,502,017	$10,581,741	$12,326,631	$20,098,414	$27,340,780	$31,493,416	$31,622,408	$24,526,092	$220,823,173

Current Residential Rates

	Distribution Charge Per Mcf	GCA Per Mcf	Total Per Mcf	Average Annual Mcf	Annual Variable Charges	Monthly Customer Charge	Annual Customer Charge	Monthly PRP Charge	Distribution PRP Charge	Annual PRP Charge	Average Annual Bill	
Atmos Energy	$ 1.5483	$ 4.0815	$ 5.63	64	$ 360.31	$ 19.30	$ 231.60		$ 0.2494	$ 15.96	$ 607.87	1
Columbia	$ 5.2528	$ 4.1328	$ 9.39	64	$ 600.68	$ 20.05	$ 240.60		$ 0.5301	$ 33.93	$ 875.20	3
Delta	$ 5.2539	$ 5.6858	$ 10.94	64	$ 700.14	$ 24.30	$ 291.60		$ 0.3280	$ 20.99	$ 1,012.73	5
Duke	$ 5.2474	$ 5.1830	$ 10.43	64	$ 667.55	$ 17.80	$ 213.60		$ 1.4000	$ 89.60	$ 970.75	4
LG&E	$ 5.1809	$ 3.0887	$ 8.27	64	$ 529.25	$ 20.07	$ 240.85	$ 2.60		$ 31.20	$ 801.30	2

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

TESTIMONY OF T. RYAN AUSTIN

INDEX TO THE DIRECT TESTIMONY
OF T. RYAN AUSTIN, WITNESS FOR
ATMOS ENERGY CORPORATION

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EXHIBITS

Exhibit TRA-1	Pipeline and Hazardous Materials Safety Administration, 84 Fed. Reg. 52180-52257 (Oct. 1, 2019) ("Mega Rule Part 1")
Exhibit TRA-2	ADB-2021-01 – PHMSA Advisory Bulletin, Statutory Mandate To Update Inspection and Maintenance Plans To Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas From Pipeline Facilities
Exhibit TRA-3	Pipeline and Hazardous Materials Safety Administration, 87 Fed. Reg. 52224-52279 (Aug. 24, 2022) ("Mega Rule Part 2")
Exhibit TRA-4	Pipeline and Hazardous Materials Safety Administration, 86 Fed. Reg. 63266-63299 (Nov. 15, 2021) ("Mega Rule Part 3")
Exhibit TRA-5	Atmos Energy Kentucky 192.624 Schedule
Exhibit TRA-6	Atmos Energy Fiscal Year 2025 Capital Projects
Exhibit TRA-7	Atmos Energy Fiscal Year 2026 Capital Projects
Exhibit TRA-8	ADB-2007-01 – PHMSA Advisory Bulletin, Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is T. Ryan Austin. My business address is 3275 Highland Pointe Drive, Owensboro, KY 42303.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Vice President of Technical Services for Atmos Energy Corporation's Kentucky/Mid-States Division.

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. My current responsibilities for the Company include oversight of engineering, geographic information systems, measurement, compliance, safety, related information technology, and procurement. My department is responsible for execution of Projects within our Pipeline Integrity Plan, Annual DOT filings, Contracting, and Project Management for planned system growth, improvement, and replacement projects. I previously served as the Program Manager for the Kentucky Pipeline Replacement Program from 2015 through 2017.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in Civil Engineering from The University of Evansville in 2000. I am a Registered Professional Engineer in the Commonwealth of Kentucky. I have been employed by Atmos Energy for 15 years. During my time at Atmos Energy I have held engineering positions of increasing responsibility (Engineer 1 – Senior 2009-2015) in Owensboro, Manager of Engineering Services with responsibilities of the Kentucky Bare Steel Pipe Replacement Program (2015-

2017) and VP of Operations for Kentucky (2017-2019) - before moving to my current role as Vice President of Technical Services in June of 2019.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes, I am a member of the American Gas Association and serve on its Transmission Integrity Management Committee. I also serve as a member on the Operations and Engineering Committee of the Kentucky Gas Association.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION OR OTHER REGULATORY ENTITIES?

A. Yes. I testified before the Commission in Case Nos. 2021-00214, 2022-00222, and 2023-00231.[1]

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits, which are attached to my testimony:

Exhibit TRA-1	Pipeline and Hazardous Materials Safety Administration, 84 Fed. Reg. 52180-52257 (Oct. 1, 2019) ("Mega Rule Part 1")
Exhibit TRA-2	ADB-2021-01 – PHMSA Advisory Bulletin, Statutory Mandate To Update Inspection and Maintenance Plans To Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas From Pipeline Facilities
Exhibit TRA-3	Pipeline and Hazardous Materials Safety Administration, 87 Fed. Reg. 52224-52279 (Aug. 24, 2022) ("Mega Rule Part 2")

[1] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (filed June 30, 2021); Case No. 2022-00222, *Electronic Application of Atmos Energy Corporation to Establish PRP Rider Rates for Twelve Month Period Beginning October 1, 2022* (filed July 29, 2022); Case No 2023-00231, *Electronic Application of Atmos Energy Corporation for PRP Rider Rates Beginning October 1, 2023* (filed July 24, 2023).

Exhibit TRA-4	Pipeline and Hazardous Materials Safety Administration, 86 Fed. Reg. 63266-63299 (Nov. 15, 2021) ("Mega Rule Part 3")
Exhibit TRA-5	Atmos Energy Kentucky 192.624 Schedule
Exhibit TRA-6	Atmos Energy Fiscal Year 2025 Capital Projects
Exhibit TRA-7	Atmos Energy Fiscal Year 2026 Capital Projects
Exhibit TRA-8	ADB-2007-01 – PHMSA Advisory Bulletin, Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

II. SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe ongoing operations activities on the Kentucky system and to support the reasonableness and necessity of the current and proposed capital investment in the Kentucky system. In particular, I support the prudence of Atmos Energy Corporation's ("Atmos Energy" or "Company") proposed capital investments through the test year. I also support the Company's proposal to establish a Pipeline Modernization Rider ("PM Rider") in Kentucky to enable the Company to recover costs associated with compliance with recently enacted regulations promulgated by the U.S. Department of Transportation Pipeline and Hazardous Materials Administration ("PHMSA"). This proposal is primarily associated with a set of recently enacted PHMSA rules known as the "Mega Rule," which was implemented in three parts addressing transmission integrity management, corrosion control, repair criteria, inspection, and maximum operating pressure near High Consequence Areas ("HCAs"), which will require replacement

of various segments of Atmos Energy's transmission system in Kentucky above and beyond what is being replaced through the Company's existing Pipeline Replacement Program ("PRP"). My testimony further supports the Company's formal request for the removal of caps on capital investment currently in place by the Kentucky Public Service Commission ("Commission") for the Company's PRP and non-PRP capital programs such that all prudently incurred capital needs are recoverable through Atmos Energy's rates. Finally, my testimony supports the Company's ongoing PRP mechanism and bare steel replacement, as well as an overview of federal and Department of Transportation ("DOT") rules.

Q. PLEASE PROVIDE AN OVERVIEW OF ATMOS ENERGY'S FACILITIES IN KENTUCKY.

A. In Kentucky, Atmos Energy operates approximately 4,200 miles of distribution main and 193.4 miles of transmission to safely and reliably serve its 180,781 residential, commercial, industrial, and transportation customers.

Q. PLEASE EXPLAIN WHY ATMOS ENERGY IS PROPOSING THE PM RIDER IN THIS PROCEEDING.

A. Atmos Energy's vision is to be the safest provider of natural gas services, which in today's pipeline safety regulatory framework leads to a need for supportive regulatory constructs designed to provide access to the capital necessary to continue to provide safe and reliable service. Atmos Energy has identified necessary capital projects to replace segments of our transmission system that are appropriately reviewed by the Commission through an annual mechanism that allows for

recovery of prudently incurred capital expenditures required for compliance with the Mega Rule similar to the recovery authorized through the PRP Rider.

Q. PLEASE DESCRIBE THE DRIVING FACTORS FOR THE PROPOSALS REGARDING RECOVERY OF SAFETY AND RELIABILITY INVESTMENT, INCLUDING THE PM RIDER PROPOSAL.

A. The goal of pipeline safety regulation in the natural gas industry is to set operational standards that advance the safe transportation and delivery of natural gas to each utility's customers. PHMSA has carefully developed a rigorous set of *minimum* standards, which are codified in Title 49 CFR Parts 191-199. The Kentucky Public Service Commission is the agency authorized to enforce these standards in Kentucky. Through this regulatory framework, Atmos Energy receives guidance and is accountable to safely operate and maintain its system. Atmos Energy diligently works to meet and surpass the requirements of these regulations through its own proactive efforts as well as cooperation with the Commission in maintaining compliance. In this way, we can build upon the standards set forth by our regulatory bodies to remain steadfast in our commitment to the safety of our customers, and the oversight of our regulators continuously confirms that we are meeting these standards for a safe natural gas transmission and distribution system. To meet this level of commitment, Atmos Energy must be able to present its requests for capital spending to the Commission in a manner that continues to provide full transparency for the Commission's determination of prudence as well as timely updates to rates to meet the capital needs of the system.

This need for continual investment applies not only to safety-compliance driven investments recovered through the PRP Rider and proposed to be recovered through the PM Rider, but also to improvements and additions to Atmos Energy's distribution and transmission systems overall to meet the growing demand for reliable energy. In addition, the Company needs to ensure that it is adequately prepared and can support economic development across the Commonwealth.

Demand for natural gas service in Kentucky continues to grow, especially with the Commonwealth's success in attracting new industry to Atmos Energy's service territory. Recent initiatives by the Governor's office and the Cabinet for Economic Development have resulted in Kentucky being a location of choice for prospective business and businesses looking at expansion. Across Atmos Energy's service territory businesses such as electric vehicle battery manufacturing and large bourbon distilleries require sizeable volumes of natural gas, and the Company desires to be able to extend and provide safe and reliable gas service to these developments. To position Atmos Energy to respond to the reliability and economic growth needs in Kentucky, the Company must be allowed to propose the level of capital investment reasonable and necessary for those purposes. The current limitations on Atmos Energy's opportunity to recover for needed capital investments (which began in 2018) work in contravention to Atmos Energy's commitment to support the needs of its Kentucky customers and the Kentucky economy as a whole.

Q. PLEASE DESCRIBE ATMOS ENERGY'S SYSTEM AS IT RELATES TO BARE STEEL PIPELINE AND ALDYL-A PIPELINE.

A. Today, Atmos Energy's Kentucky system has approximately 88 miles remaining of bare steel pipe in its system, most of which has been in place since before the 1960s. In addition, of the early generation plastic pipe in Atmos Energy's Kentucky system, there are approximately 199 miles of Aldyl-A pipe. The natural gas industry has determined that these materials are no longer appropriate for use in the construction of natural gas distribution systems. Bare steel and early generation plastic pipes deteriorate with age and are prone to leaks, which impacts both the safety and reliability of the pipeline system. Atmos Energy employs measures identified in our Distribution Integrity Management Plan ("DIMP") to address such risks on its system, and Distribution Facilities Replacement is one of those measures, particularly to address the threats posed by these material types. The mitigation of these threats is paramount to continued system safety and reliability.

III. PIPELINE SAFETY REGULATIONS

Q. IN YOUR POSITION, ARE YOU FAMILIAR WITH FEDERAL AND STATE REGULATIONS REGARDING PIPELINE SAFETY AND INTEGRITY?

A. Yes.

Q. IS ATMOS ENERGY SUBJECT TO THE PHMSA'S RULES AND REGULATIONS REGARDING GAS DISTRIBUTION PIPELINE SAFETY?

A. Yes. Atmos Energy is subject to the PHMSA rules and regulations as those are promulgated by the U.S. Department of Transportation and adopted by the Commission for Kentucky natural gas local distribution companies.

Q. DO PIPELINE SAFETY REGULATIONS SPECIFY THE FULL EXTENT OF ACTIONS A PRUDENT OPERATOR IS EXPECTED TO UNDERTAKE WHEN OPERATING THEIR SYSTEM?

A. No. A major challenge of developing uniform ways to address safety of natural gas pipelines is that the majority of this critical infrastructure is underground, making threats not easily observable or known. As a result, it is impossible for regulations in this area to be completely prescriptive. The pipeline safety regulations, or code (including the federal code and complementary codes adopted by the states), must therefore provide the minimum that should be done to construct, operate, and maintain a natural gas system, which serves as a framework in which operators must use their discretion to implement those standards in a manner that enhances safety on its system given the constraints inherent in the process.

Q. PLEASE PROVIDE EXAMPLES OF HOW PHMSA REGULATIONS DIRECT OPERATORS TO TAKE ACTION TO ADDRESS SAFETY.

A. As I mentioned above, federal and state regulations that govern the natural gas industry are the minimum standards allowed by law as stated in 49 CFR Part 192.1(a). Atmos Energy continues to use 49 CFR Part 191 and 192 as the starting point for establishing safe practices and procedures for constructing, operating, and maintaining our natural gas systems. Some of these regulations are prescriptive in nature with clearly defined required activities and timeline. A clear example of this

is Subpart M – Maintenance, which has prescriptive operations procedure requirements and timelines for activities that address risk on the system such as patrolling, leak surveys, leak repair, inspection, and testing of regulating stations, etc.

Other regulations are less prescriptive and put the burden on the Operator to establish the activities needed to comply with said regulation. A clear example of this is Subpart P – Gas Distribution Pipeline Integrity Management ("IM" or "DIM"). In the opening paragraph of the Background section of PHMSA's published Final Rule that established Subpart P, PHMSA states, "The IM approach was designed to promote continuous improvement in the pipeline safety by requiring operators to identify and invest in risk control measures *beyond core regulatory requirements*" (emphasis added). Thus, exceeding that "minimum guidance" is an additional regulatory requirement of PHMSA and the state pipeline safety regulators that are designated by PHMSA to enforce Parts 191 and 192. For example, Part 192.1007(c) requires the operator to evaluate and rank risk: "An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure." In this way, the regulation leaves to the operator the decisions of the factors and methodology that should be used to identify and address risk and the measures used to address such identified risks.

Q. IS THERE ADDITIONAL INFORMATION REGARDING ATMOS ENERGY'S DIM PLAN THAT HELPS EXPLAIN THIS CONCEPT OF ADDRESSING RISK ON THE SYSTEM THROUGH DISTRIBUTION FACILITIES REPLACEMENT?

A. Yes. It is helpful to consider the Introduction to Atmos Energy's adopted and approved DIM Plan:

> Atmos Energy considers this IM Plan as its written procedures for the development and the implementation of the required Distribution Integrity Management elements as referenced in 49 CFR Part 192, Subpart P, §192.1007. The purpose of Atmos Energy's IM Plan is to identify threats, assess and mitigate risks, and measure performance of mitigating actions.
>
> In developing this written plan, Atmos Energy relied, either wholly or in part, upon the requirements contained in 49 CFR Part 192, Subpart P, Gas Distribution Pipeline Integrity Management (IM) and was specifically modeled after the seven required written IMP elements contained in §192.1007.

There are several things to note about this quotation. First, the DIM Plan is considered "written procedures" pursuant to Part 192, and Atmos Energy ***must comply*** with all such written procedures or be subject to violations of pipeline safety regulations and potential federal and state penalties.[2] Second, the elements of Atmos Energy's DIM Plan are taken directly from Part 192.1007. The seven key elements of a DIMP plan are:

1. Knowledge of distribution system
2. Identify threats
3. Evaluate relative risk

[2] *See* 49 C.F.R. 192.13(c) ("Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.").

4. Identify and implement measures to reduce risk

5. Measure performance, monitor results, and evaluate effectiveness

6. Periodic evaluation and improvement

7. Report results

Through the DIMP process, the relative risks of all Kentucky assets are assessed, and appropriate measures from the list of 19 programs/policies listed in the DIM Plan are identified and implemented to address the identified risks as required. One of the defined programs is the "Distribution Facility Replacement Program." The description of that program is as follows:

> Atmos Energy Operating Divisions plan and prioritize replacements of unprotected steel, wrought iron, historic plastic (e.g., PVC, ABS, Aldyl-A) and other pipe materials that are known to leak consistent with the requirements of Section 114 of the PIPES Act of 2020.[3] These programs take into consideration factors including, but not limited to, pipe material and operation and maintenance history, including the frequency of leak or failure events. Details of the respective plans are available in each operating division.
>
> Threats / Risks Mitigated
>
> As a result of the prioritized replacement of facilities on Atmos Energy's distribution systems, the following threats or risks are mitigated:
>
> • Corrosion
> • Excavation Damage
> • Natural Force Damage
> • Other Outside Force Damage
> • Materials
> • Joints/Welds
> • Equipment Failure

[3] *See, e.g.*, PHMSA Information Webinar for Section 114 of the PIPES Act of 2020, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-03/Section_114_Webinar.pdf, at Slide 9 ("By Dec 27, 2021, operators must update their inspection and maintenance plans to address: • Eliminating hazardous leaks of natural gas; • Minimizing releases of natural gas; • Replacement or remediation of all pipelines that are known to leak").

Atmos Energy's process for determining the priority of facilities replacement in Kentucky begins with this requirement in the DIM Plan. Through the DIMP process, assets on the Kentucky system have been identified as relatively high risk and sequenced for replacement, including bare steel and Aldyl-A assets.

Q. WHEN THE PHMSA PIPELINE SAFETY RULEMAKING PROCESS WAS INITIATED, DID IT PROVIDE ANY INSIGHT INTO THE STATES' ROLES IN DISTRIBUTION PIPELINE SAFETY MEASURES?

A. Yes. PHMSA emphasized the importance of oversight performed directly by the States. PHMSA stated specifically:

> *States must implement the minimum standards established by PHMSA but have a variety of ways in which they can oversee distribution pipeline safety. They can simply mirror the Federal pipeline safety program; they can impose additional requirements, beyond the Federal minimum; they can engage in special oversight programs with individual operators or groups of operators; or finally, they can provide incentives for safety improvements, often through their rate-setting authority. (emphasis added)*

> *It is appropriate that the principal actions for regulating distribution pipeline safety rest with the States. States need to balance safety and affordability. They need to ensure that the particular needs of their citizenry are fulfilled....*[4]

Q. HAVE THE FEDERAL AND STATE PIPELINE SAFETY CHANGES DISCUSSED PREVIOUSLY IMPACTED THE WAY THAT NATURAL GAS COMPANIES MONITOR AND MANAGE THE SAFETY OF THEIR DISTRIBUTION SYSTEMS?

[4] Notice of Proposed Rulemaking, 73 Fed. Reg. 36015 at 36017.

A. Absolutely. The federal changes and the Call to Action[5] have resulted in an increasingly proactive approach to pipeline safety.

Q. PLEASE DISCUSS RECENT CHANGES TO PIPELINE SAFETY LAWS AND REGULATIONS THAT SUPPORT ATMOS ENERGY'S COMMITMENT TO AND PLANS FOR TRANSMISSION AND DISTRIBUTION REPLACEMENT.

A. In 2016 PHMSA published a Notice of Proposed Rulemaking ("NPRM") in response to the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and related federal mandates and recommendations. The proposed rules in this NPRM have been collectively termed the "Mega Rule." On October 19, 2019, the first of these three separate rulemakings ("Mega Rule Part 1") was finalized with an effective date of July 1, 2020.[6] Mega Rule Part 1 requires operators of gas transmission pipelines constructed before 1970 to determine the material strength of lines with certain properties installed in specific operating areas by reconfirming the Maximum Allowable Operating Pressure ("MAOP").[7] The requirements of Mega Rule Part 1 are attached to my direct testimony as Exhibit TRA-1. In addition, On December 27, 2020, Congress signed into effect the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 ("PIPES Act of 2020"), which outlines provisions intended to continue to enhance safety, increase transparency, and refine the existing rulemaking process. One provision was a directive for natural gas operators to, within one year, evaluate their existing plans

[5] PHMSA Call to Action Letter to National Association of Regulatory Utility Commissioners, Dec. 19, 2011, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/PHMSA%20111011-002%20NARUC.pdf.
[6] Pipeline and Hazardous Materials Safety Administration, 84 Fed. Reg. 52180-52257 (Oct. 1, 2019).
[7] *See* 49 C.F.R. §§ 192.624, 192.632.

and take into consideration measures which would contribute to public safety and protect the environment. In advisory bulletin ADB-2021-01 dated June 4, 2021, PHMSA outlined its intention to begin performing inspections in 2022 on the adequacy of operators' updated plans to meet the intent of Section 114 of the PIPES Act of 2020, including the requirement that "[o]perators must also revise their plans to address the replacement or remediation of pipeline facilities that are known to leak based on their material, design, or past operating and maintenance history."[8] Advisory Bulletin ADB-2021-01 is attached to my direct testimony as Exhibit TRA-2. The second part of the Mega Rule ("Mega Rule Part 2"), and the last of the three parts of the Mega Rule to be published, was published on August 24, 2022 and the majority took effect on May 24, 2023.[9] Mega Rule Part 2 includes provisions to enhance the repair criteria for pipeline anomalies.[10] It also expands the repair criteria to include areas outside of High Consequence Areas ("HCAs"),[11] which will also likely increase the quantity of pipe replaced each year.[12] The requirements of Mega Rule Part 2 are attached to my direct testimony as Exhibit TRA-3. Part 3 of the Mega Rule ("Mega Rule Part 3") was promulgated Nov. 15, 2021, with an effective date of May 16, 2022, and extends federal safety requirements to onshore gas gathering pipelines with large diameters and high

[8] Pipeline and Hazardous Materials Safety Administration, ADB-2021-01, *available at* https://public-inspection.federalregister.gov/2021-12155.pdf.
[9] Pipeline and Hazardous Materials Safety Administration, 87 Fed. Reg. 52224-52279 (Aug. 24, 2022).
[10] *See, e.g.*, 49 C.F.R. §§ 192.714, 192.935.
[11] "Pipeline safety regulations use the concept of 'High Consequence Areas' (HCAs), to identify specific locales and areas where a release could have the most significant adverse consequences. Once identified, operators are required to devote additional focus, efforts, and analysis in HCAs to ensure the integrity of pipelines." Fact Sheet: High Consequence Areas, Pipeline & Hazardous Materials Safety Administration, *available at* https://primis.phmsa.dot.gov/comm/factsheets/fshca.htm.
[12] *See, e.g.*, 49 C.F.R. § 192.714.

operating pressures.[13] The requirements of Mega Rule Part 3 are attached to my direct testimony as Exhibit TRA-4. As of now, the Mega Rule is applicable only to assets classified as transmission.

Q. WHY WAS THE MEGA RULE ISSUED?

A. The Mega Rule was issued to strengthen the safety and environmental protection of onshore gas transmission pipelines throughout the United States. The Mega Rule incorporates lessons learned through the investigation of the September 9, 2010, gas transmission pipeline incident in San Bruno, California, which resulted in the death of eight people and injuries to more than 60 others.[14] In doing so, the Mega Rule revises the pipeline safety regulations that PHMSA issued under Title 49 of the Code of Federal Regulations, Part 192.

Q. IS COMPLIANCE WITH THE MEGA RULE REQUIRED?

A. Yes. For the Company's Kentucky transmission pipelines, the new requirements of Mega Rule Part 1 regarding MAOP reconfirmation are a primary driver of the Company's planned future activity.

Q. HOW MANY MILES OF TRANSMISSION PIPELINE ARE CURRENTLY IN ATMOS ENERGY'S KENTUCKY SYSTEM?

A. The Company currently has approximately 193.4 miles of classified transmission pipeline in Kentucky.

Q. PLEASE DISCUSS SOME OF THE PRIMARY REQUIREMENTS OF MEGA RULE PART 1.

[13] Pipeline and Hazardous Materials Safety Administration, 86 Fed. Reg. 63266-63299 (Nov. 15, 2021).
[14] *See generally* Pipeline Accident Report, NTSB/PAR-11/01 PB 2011-916501.

A. Part 1 of the Mega Rule, as mentioned above, requires MAOP Reconfirmation and material verification assessments outside High Consequence Areas ("HCAs"). In particular, Part 1 focuses on the actions an operator must take to reconfirm the MAOP of previously untested natural gas transmission pipelines, the periodic assessment of pipelines in areas not designated as HCAs, the reporting of exceedances of MAOP, the consideration of seismicity as a risk factor in integrity management, safety features on in-line inspection launchers and receivers, a 6-month grace period for 7-calendar-year integrity management reassessment intervals, and related recordkeeping provisions.[15] In particular this requires:

- Complete MAOP Reconfirmation of 50% of affected pipeline mileage by July 2028 (§192.624);
- Complete MAOP Reconfirmation of 100% of affected pipeline mileage by July 2035 (§192.624);
- Complete integrity assessment of non-HCA Class 3 and 4 Locations, and Piggable Moderate Consequence Areas ("MCAs") by July 2034 (§192.710); and
- Material verification as required to support all activities (§192.607).

Q. IS THE MEGA RULE CURRENTLY IN EFFECT?

A. Yes.

Q. PLEASE DISCUSS THE IMPACT OF THE MAOP RECONFIRMATION REQUIREMENT OF THE MEGA RULE FOR ATMOS ENERGY'S KENTUCKY TRANSMISSION LINES?

A. The reconfirmation of MAOP requirements per §192.624 on the Company's Kentucky transmission assets is expected to have a sizable impact. PHMSA has

[15] https://www.federalregister.gov/documents/2019/10/01/2019-20306/pipeline-safety-safety-of-gas-transmission-pipelines-maop-reconfirmation-expansion-of-assessment

identified six methods whereby an operator may reconfirm the MAOP of affected pipelines.[16] These methods are as follows:

1. Perform a pressure test;
2. Reduce the pressure;
3. Perform an Engineering Critical Assessment ("ECA") in accordance with §192.632;
4. Replace the pipe;
5. Reduce the pressure for those pipelines with a potential impact radius of 150 feet or less (smaller diameter, lower MAOP pipelines); or
6. Use an alternative technology that provides a documented engineering analysis for establishing MAOP.

Q. HOW MANY TRANSMISSION MILES WILL REQUIRE RECONFIRMATION?

A. Approximately 20.4 miles of the Company's Kentucky transmission lines require MAOP reconfirmation per §192.624. To date, the Company has reconfirmed 2.3 miles via pressure test, so 18.1 miles remain.

Q. PLEASE DISCUSS THE IMPACT OF THE NON-HCA REQUIREMENT OF THE MEGA RULE FOR ATMOS ENERGY'S KENTUCKY TRANSMISSION LINES?

A. Part 192.710 requires transmission pipelines in Class 3 or 4 locations to be assessed in the same manner as HCAs are assessed. Atmos Energy is required to complete the baseline assessments by July 2034, as noted above.

Q. HOW MANY NON-HCA TRANSMISSION MILES REQUIRE ONGOING ASSESSMENTS?

[16] 49 C.F.R. § 192.624(c).

A. Approximately 20.1 miles of non-HCA transmission miles have been added to the Company's assessment plan, as per §192.710. Of these 20.1 miles, 8.0 miles fall under both §§192.624 and 192.710.

Q. PLEASE DISCUSS THE COMPANY'S STRATEGY TO ADDRESS THE NEW MEGA RULE REQUIREMENTS?

A. Where the Company can perform pressure tests or reduce pressure without jeopardizing safety and reliability it is currently in the process of doing so in order to achieve compliance. As noted above, the Company has reconfirmed 2.3 miles of transmission pipe via pressure test. At this time, an additional 3.1 miles are planned for a pressure reduction, while another 1.0 mile is a candidate for a pressure test. However, for approximately 14.0 miles of the Company's affected transmission pipeline, the Company believes that pipe replacement would be the most cost-efficient way to re-establish the MAOP of the affected pipeline segments as pressure testing or reducing the pressure in these segments is not possible. Replacement will allow the Company to keep our customers in service as well as modernize vintage pipeline and remove them from transmission lines to distribution lines (*i.e.* less than 20% of specified minimum yield strength) so the lines will operate with a higher factor of safety. An ancillary benefit of the replacement work is that the Company will be able to install larger diameter pipe to enhance system reliability and support the continued development of the areas where the

replacement work will occur as these areas have grown significantly since the original pipe was installed.

Q. CAN YOU PROVIDE AN EXHIBIT SHOWING THE MAKEUP OF THE COMPANY'S AFFECTED KENTUCKY TRANSMISSION ASSETS AND THE PLANNED MAOP RECONFIRMATION ACTIVITIES?

A. Yes. Exhibit TRA-5 attached to my testimony shows the currently affected transmission assets that require MAOP reconfirmation, as well as the Company's long-term plan to meet the Mega Rule requirements. As I mentioned earlier, the 14.0 miles of transmission pipelines proposed for replacement are all pre-November 12, 1970 lines, which is when 49 CFR Part 192 went into effect. Of those 14.0 miles, 4.7 miles of these transmission lines were installed between 1956-1959, and 5.9 miles were installed in 1955 or prior to that time.

Q. WHY IS PERFORMING A PRESSURE TEST ON THESE LINES NOT AN EFFECTIVE OPTION FOR THE COMPANY FOR MOST OF THESE TRANSMISSION LINES?

A. Where pressure tests can be safely performed the Company has done so or will plan to do so. To date, the Company has already reconfirmed 2.3 miles of transmission assets via pressure test, and also plans to pressure test an additional 1.0 miles in Hawesville, KY in 2027 as shown on Exhibit TRA-5. There are several reasons why pressure test is not a practical option for a large portion of the Company's Kentucky transmission assets. Primarily, the affected pipelines are not piggable due to factors including diameter changes, stopple fittings, tees for regulator stations and farm tap services, and insufficient radius bends. These factors also

make the pipelines impractical to test with water as it would be nearly impossible to remove all the water from the lines because they are not piggable. In pipeline safety, "piggable" refers to the ability of a pipeline to allow a pig to enter and exit without damaging the pipe or the pig. Pigs are devices that are inserted into pipelines to clean or inspect them. In addition, the 14.0 miles proposed for replacement were installed prior to the adoption of the record-keeping requirements in Part 192, and records on wall thickness and grade necessary to perform pressure-testing do not exist for these assets. To confirm the MAOP via a pressure test with water poses risks, as the Company would need to pressure the line to at least 1.5 times its MAOP. To safely perform these tests, the wall thickness and grade must be known. Otherwise, manufacturing-related or construction-related defects may fail due to overstressing the pipe beyond 100% of its yield strength. This would potentially result, beyond the safety risks alone, in replacing significant amounts of pipe because of testing. In addition, the pressure testing would heavily increase O&M spending not just for the cost of pressure testing, but also to account for long-term outages while the tests and any replacements are performed that would require sustained use of liquified natural gas ("LNG") or compressed natural gas ("CNG") supply to be trucked in continuously to supply those customers with natural gas in the interim period.

Q. WHY IS THE COMPANY UNABLE TO REDUCE THE PRESSURE ON ITS TRANSMISSION LINES?

A. For those transmission lines where the pressure can be safely reduced and provide long-term reliability the Company is planning to do so as shown in Exhibit TRA-

5. For the lines where the Company is proposing replacement reducing the pressure on the affected transmission lines would likely lead to significant and prolonged customer outages and the Company would be unable to serve customers with the mandated pressures. Many customers would permanently lose their natural gas service. For similar reasons, this is also why the Company is unable to reduce the pressure for those pipelines with a potential impact radius of 150 feet or less.

Q. WHY IS PERFORMING AN ENGINEERING CRITICAL ANALYSIS ALSO NOT AN OPTION FOR THE COMPANY?

A. The information required to complete an Engineering Critical Analysis ("ECA") would be prohibitive or impossible for the Company to obtain. The full requirements of performing a successful ECA are outlined in 49 CFR §192.632. The material properties required to perform an ECA include wall thickness and grade which the Company does not have and would require in-line inspection, using an instrumental tool known as a "smart pig." As noted previously, the proposed replacement pipelines are not piggable. The ECA also requires pressure tests to perform the analysis which are also difficult and costly to obtain as also mentioned.

Q. IS THE COMPANY ABLE TO USE AN ALTERNATIVE TECHNOLOLGY THAT PROVIDES A DOCUMENTED ENGINEERING ANALYSIS FOR ESTABLISHING MAOP?

A. No. Any alternative technology must include records that do not exist, for instance the pipe grade, wall thickness, and data from previous in-line inspections. Most of this data would be collected from using a smart pig, and the Company's transmission assets are not piggable. Any alternative technology would run into

similar challenges to pressure testing and would be cost prohibitive, risk not achieving compliance due to unknown factors with the pipe, and cause long-term disruption to our customers.

Q. WHY IS REPLACEMENT THE MOST EFFECTIVE, AND SAFEST, OPTION FOR THE MAOP RECONFIRMATION OF THESE TRANSMISSION LINES?

A. The replacement of these pipelines will allow the Company to install new pipe using modern construction practices, and enhanced safety design factors that will allow us to reclassify them from transmission to high pressure distribution where they will operate with a higher level of safety. The pipelines proposed for replacement in Exhibit TRA-5 are all aged where replacement is the best option to enhance safety. In addition, the replacement of these pipelines will prevent long-term or permanent customer loss of gas services, as well as prevent long-term O&M costs associated with MAOP reconfirmation methods other than replacement as I described above. For the lines where the Company has proposed replacement any other reconfirmation method potentially risks failure to achieve compliance with the Mega Rule.

Q. HOW MANY MILES OF TRANSMISSION LINE HAVE THE COMPANY IDENTIFIED THAT REQUIRE RECONFIRMATION?

A. Currently, the Company has identified 20.4 miles that require reconfirmation. This number is not static and as class locations potentially change and additional mileage may require reconfirmation in the future.

Q. WHAT ARE THE ADDITIONAL SAFETY BENEFITS OF LONG-TERM REPLACEMENT OF THESE TRANSMISSION PIPELINES?

A. Replacing aged transmission lines allows the Company to continue to provide safe and reliable natural gas service by operating pipelines constructed of modern, up-to-date materials, at lower stress levels on the pipe and maintain compliance with promulgated PHMSA regulations. The resulting increase in margins of safety is a definite benefit to the citizens that rely on natural gas for heating, hot water, cooking, and for business and industry to develop and maintain the high standard of living that Kentuckians enjoy.

Q. IF THESE TRANSMISSION ASSETS ARE NOT REPLACED, WOULD THERE BE ONGOING INCREMENTAL O&M ASSOCIATED WITH MEGA RULE COMPLIANCE?

A. Yes. To summarize, options other than replacement would result in multiple incremental costs and would reduce long-term reliability of service. In addition to enhanced leak surveys, these lines would be monitored continually and subject to outages at various points as reconfirmation activities other than pipeline replacement were performed and sections of pipeline removed from service. These outages would require long-term and sustained use of LNG and CNG supply to be trucked in, which would be costly to Atmos Energy's customers as well as operationally challenging to sustain for a prolonged period. As noted above, currently 8.0 miles of transmission pipeline are now required to be assessed every seven years for as long as these transmission assets remain in service which is a continual O&M expense requiring specialized consultants and extensive in-the-

ditch examinations. The examinations are both costly and a safety risk for the Company's employees and contractors.

Q. DO YOU EXPECT CLASS LOCATIONS TO CHANGE IN THE FUTURE THAT MAY ADD ADDITIONAL MILEAGE?

A. Yes. As the Company's service area continues to experience customer growth, it is highly likely that more locations will be reclassified as Class 3, and some transmission lines would fall under the purview of the Mega Rule.

Q. WILL INVESTMENT RELATED TO MEGA RULE COMPLIANCE BE ONGOING FOR THE COMPANY?

A. Yes. The Company has outlined its long-term plan for Mega Rule compliance in Exhibit TRA-5 and believes the approval of the proposed PM Rider is the appropriate approach to support compliance with these specific PHMSA regulations. The Company has included the estimated costs of compliance projects through fiscal year 2026 based on latest estimates. These costs are included within Exhibit TRA-5. Atmos Energy has provided these estimated costs in an effort to provide the Commission with the most accurate information available for an initial estimated impact of the Company's compliance obligations. Since class locations changes could potentially impact the Company's cost of compliance with the Mega Rule, if the PM Rider is approved by the Commission, Atmos Energy would make annual filings with the Commission regarding the costs of compliance projects to be included in the PM Rider. This would allow Atmos Energy to continue to present the Commission with the most accurate information regarding the costs of the

compliance projects required for the Commission's review, consideration, and approval.

Q. WILL THE COMPANY'S PROPOSED PIPELINE MODERNIZATION RIDER HELP CAPTURE COSTS ASSOCIATED WITH THE MEGA RULE AND ALLOW FOR TIMELY REVIEW BY THE COMMISSION?

A. Yes. The PM Rider will allow for an annual review, discovery, and engagement with the Commission on the Company's progress towards Mega Rule compliance. The PM Rider would allow for these capital costs to be tracked separately, similar to the Company's current PRP mechanism.

Q. WILL THE COMPANY'S REPLACEMENT PROJECTS RECOVERED THROUGH THE PM RIDER HAVE AN IMPACT ON ITS ONGOING O&M EXPENSES?

A. Yes. While it is difficult to track O&M expenses that would have been incurred, O&M expenses currently incurred to maintain compliance on these assets will be reduced once they are classified as distribution assets. For example, there are reduced patrolling and leakage survey requirements for distribution mains. The main difference in O&M expenses is a result of the fact that they will no longer fall under the transmission integrity management program, with costly re-assessments required every seven years for 8.0 miles of these pipelines as long as they remain in service.

Q. IS THE PROPOSED PM RIDER SUPPOSED TO BE A CATCH-ALL FOR FUTURE PIPELINE REPLACEMENT PROJECTS?

A. No. The Company is proposing the PM Rider to initially limit its applicability to

the cost of compliance to recover costs associated with compliance with specific regulations promulgated by PHMSA, in particular the Mega Rule. This structure would be similar to Duke Energy's approved Pipeline Modernization Mechanism which was driven by the PHMSA Mega Rule and has initially been limited to Duke's AM07 pipeline which is a multi-year project initially estimated to be approximately $191.2 million.[17] These costs would be reviewed by the Commission annually subject to the Commission's full review similar to the Company's existing PRP mechanism.

Q. HAS THE COMMISSION NOTED THAT A RIDER IS APPROPRIATE TO ADDRESS SPECIFIC DIRECTIVES FROM PHMSA?

A. Yes. In Case No. 2021-00214 the Commission reminded Atmos Energy "that the purpose of a rider tied to capital investment in the natural gas industry is address specific problems such as bare steel or a section of pipe prone to issues and may be tied to specific directives issues by PHMSA."[18] The Company's proposed PM Rider is designed to specifically address capital investment for transmission pipe tied to the Mega Rule directive issued by PHMSA.

IV. CAPS ON CAPITAL INVESTMENT

Q. IS THE COMPANY FORMALLY REQUESTING PERMISSION FROM THE COMMISSION TO LIFT THE CAPS ON CAPITAL INVESTMENT FOR BOTH NON-PRP AND PRP CAPITAL?

[17] Case No. 2021-00190, *Electronic Application of Duke Energy Kentucky, Inc. for: 10 An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs, and 3) All Other Required Approvals, Waivers, and Relief,* final Order at 22 (Ky. PSC Dec. 28, 2021)

[18] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022), final Order at 60.

A. Yes. As discussed in the Direct Testimony of Company witness Mr. Taylor, Atmos Energy has been conducting its operations in Kentucky over the past six years making decisions about needed capital investments within the caps placed on the expenditures for which the Company can recover through its PRP Rider and its general rate cases.

Q. DOES THE COMMISSION'S DIRECTIVE IN THE 2018 ORDER ALLOW SUFFICIENT FLEXIBILITY FOR ATMOS ENERGY'S CAPITAL BUDGET TO INCLUDE ALL NECESSARY PROJECTS FOR SAFETY, RELIABILITY, AND ECONOMIC GROWTH?

A. No. The cap language in Case No. 2018-00281 limits all categories of investment outside of the bare steel projects recovered through PRP. In Case No. 2018-00281, the Commission directed that for non-PRP "[c]apital project spending should be consistent with the DIMP and TIMP as well as limited to the 5-year historical average of capital spending on non-PRP projects."[19] Further, in the 2018 Order the Commission stated that:

> *while the Commission is not imposing a specific limit on Atmos' non-PRP capital spending in years after the forecasted test period, the Commission may prohibit a return of and on investments that it finds unreasonable and unlawful. Atmos should ensure that the projects it selects to construct are consistent with its DIMP or TIMP. Moreover, if its total non-PRP capital spending exceeds the 5-year rolling average, Atmos should scrutinize the justification for its projects closely and be prepared to provide supporting documentation showing how each project is consistent with its DIMP or TIMP. Significant increases in capital spending would raise questions about the necessity of the spending and may require additional scrutiny by the Commission.*[20]

[19] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), Order at 24.
[20] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), Order at 25.

This language creates uncertainty about non-PRP investment in general and specifically about the Company's ability to recover necessary capital investments in the system that are not related to addressing threats identified through integrity management, such projects to address growth and economic development, system reliability, or facilities necessary to serve industrial customers. For example, with growth comes the need to replace, loop, or increase pipe sizes to continue to provide reliable service to existing customers. These projects are not identified through the integrity management process to address safety threats but rather are identified through the system planning process to maintain reliable service. This fact does not make them less necessary for the provision of safe, reliable natural gas service to existing and new customers requesting service.

Q. IS THERE A NEED TO CONSTRUCT PROJECTS TO SUPPORT ECONOMIC GROWTH?

A. Yes. Kentucky is growing and is seeking to continually attract and expand industries to the Commonwealth. With this industrial growth comes the need for system expansion for natural gas usage to support these businesses and the resulting growth in the communities. Atmos Energy has, and believes it will continue to see, industrial growth that will require increased amounts of system expansion, system improvement, and public improvement to safely and reliably meet these needs. The Commission's current limitations on non-PRP capital investment mean the Company is unable to commit to many of these projects. Many of these capital projects and associated functionals are often unknown and require flexibility by the

Company to be able to serve. The Commission's current language regarding the caps does not contemplate any of these scenarios.

Q. PLEASE DISCUSS SOME CURRENT AND POTENTIAL ECONOMIC DEVELOPMENT PROJECTS THAT ARE POTENTIALLY INFEASIBLE DUE TO THE CAPS ON CAPITAL.

A. Currently, the Company is working with several electric vehicle battery manufacturers in the Hopkinsville and Bowling Green areas to determine their potential gas needs. Examples of two of these manufacturers are Ascend Elements Inc. in Hopkinsville and Envision AESC in Bowling Green. Ascend Elements' project scope is currently expected to include a $1 billion investment creating as many as 400 full-time jobs.[21] Envision AESC's investment in Kentucky is expected to be approximately $2 billion and create 2,000 full-time jobs.[22] Bowling Green also continues to grow and have more industrial prospects interested in locating at TransPark and the Company has seen continued expansion of bourbon distillers in its Shelbyville/Lawrenceburg/Springfield corridor.[23] The Company needs to be in a position to serve these important economic partners to Kentucky. With the current non-PRP caps on capital investment in place, the Company is unable to commit to being able to serve these projects and commit to long-term gas availability and service. Beyond these large projects, the Company needs to be able to continue to serve small businesses and residential growth in its service area that is both organic

[21] https://ced.ky.gov/Newsroom/NewsPage/20221020_AscendGB#:~:text=Andy%20Beshear%20joined%20local%20officials,to%20include%20up%20to%20a

[22] https://ced.ky.gov/Newsroom/NewsPage/20220830_EnvisionAESCGroundbreaking

[23] *See, e.g.*, https://ced.ky.gov/Newsroom/NewsPage/20221208_Willett

and also results when new industries locate to town. With a combination of the approval of the PM Rider to allow recovery of the projects described above for recovery through that mechanism, removal of the cap on the PRP Rider so that all risk-based pipe replacement can be proposed for recover through that mechanism, and removal of a cap on investment recovered through rate cases, Atmos Energy will be able to undertake the necessary investments and demonstrate to the Commission that those costs are prudently incurred.

Q. PLEASE DESCRIBE OTHER LIMITATIONS ON ATMOS ENERGY'S ABILITY TO SUPPORT GROWTH IN KENTUCKY.

A. I can think of several thriving areas in our service territory that are outgrowing the capacity of our system: Bowling Green, Hopkinsville, and the Shelbyville/Lawrenceburg/Springfield area. In all of these areas, there are several existing and potential industrial projects that would bring investment and jobs to the region. However, if Atmos Energy needed to make capital investment in the region to support that growth, our budget would be limited by the cap on non-PRP spending and not justifiable by DIMP as ordered by the Commission, and necessary system maintenance and safety projects that would have to take precedence. Similarly, the Commission's current PRP cap and limitation that PRP be limited in effect to bare steel necessitates the Company trying to capture everything non-bare steel related into the non-PRP caps. As the caps do not increase, but the costs of material, labor, etc. have risen, the Company is able to do less work and is required to prioritize its safety investments over investments driven solely by economic development. This has the potential to deter large industrial customers from

locating in Atmos Energy's service territory. Due to the existing caps, the Company is currently forced to tell many existing and prospective industries, as well as the Kentucky Cabinet of Economic Development, that the Company is limited on the options that it may provide to them.

Q. HOW DOES THIS NON-PRP CAP AFFECT YOUR BUDGETING PROCESS?

A. When the Company is preparing its budget each year the Company prepares with the consideration of the caps as put in place by the Commission. Planned projects necessary to continue to provide safe, reliable service to existing customers are the first priority. In addition, the Company must continue to operate its day-to-day activities within its functional project budgets that are all part of non-PRP investment. Functional projects are essentially categories of budget dollars reserved for programmatic spending that the Company must incur for its day-to-day operations. These include capital items such as our meter and growth functionals. Based on the long-term system needs of Kentucky, allowing for these two categories of capital expenditures leaves very little flexibility within the space of the caps to serve, if it all, economic development, system improvement, or public improvement projects.

Q. HAS THE COMPANY SEEN CAPITAL COSTS INCREASE SINCE THE INITIAL CAP LANGUAGE IN 2017 AND 2018?

A. Yes. The Company has seen substantial increases in capital costs in the last several years due a variety of factors including but not limited to the COVID-19 pandemic, rising inflation, geopolitical issues, and continued supply chain constraints that

have increased the labor and material costs for the Company on capital projects. These rising costs have meant the Company is able to perform less work each year based on the caps, which have remained static to the levels established in 2017 and 2018.

Q. IF THE CAPS ARE REMOVED, ARE THE COMPANY'S CAPITAL INVESTMENT PROJECTS STILL SUBJECT TO COMMISSION REVIEW?

A. Absolutely. The Commission would still have oversight on the Company's capital investment projects during the course of rate proceedings. The removal of the caps would allow the Company additional flexibility to respond as needed to the requirements of its system in order to provide safe and reliable service as well as continued economic development in Kentucky. The Commission will still have the opportunity to determine whether this spending is reasonable and necessary.

Q. GIVEN THE INCREASE IN CAPITAL COSTS, CAN YOU DISCUSS THE COMPANY'S TIMELINE ON BARE STEEL REMOVAL IN THE PRP?

A. Yes. The Commission's Order in Case No. 2017-00349 limited the Company's bare steel investment to $28 million per year in the PRP and extended the timeline by two years to 2027 to targeted bare steel replacement.[24] The Company has endeavored to complete bare steel removal within the capital limits set by the Commission by 2027. The recent order in Case No. 2023-00231 raising the PRP cap to $30 million will not, in the Company's opinion, allow the Company the opportunity to meet the Commission's proposed 2027 timeline. As of now, given

[24] Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications* (Ky. PSC May 3, 2018), Order at 41.

the constraints of the caps and the rising capital costs, the Company will require additional years to reasonably complete bare steel replacement, even if the caps are removed going forward. I discuss later in my testimony the reasons why the Company's PRP remains in the public interest and the request for the caps to be lifted to allow the Company to complete bare steel replacement in a timely manner and ultimately transition its PRP mechanism to include the replacement of Aldyl-A material identified by PHMSA.

Q. DO YOU HAVE A RECOMMENDATION AND LIST OF PROJECTS ON THE COMPANY'S FUTURE CAPITAL INVESTMENT PLANS TO PROVIDE THE COMMISSION?

A. Yes. The Company's proposed FY25 and FY26 budgets as submitted in this Case are the Company's anticipated capital projects should the Commission lift the capital restraints currently in place for non-PRP investment. I have also included these projects individually as Exhibits TRA-6 and TRA-7 in my testimony. The proposed total capital is only incrementally above the current caps, and the Company believes these projects are each individually prudent and necessary for the continued safety and reliability of the Company's system and to properly support anticipated economic development in Kentucky. Exhibits TRA-6 and TRA-7 provide in detail the individual project description, the business purpose, and the associated regulatory requirements. The Company also supplied, in response to FR_16(7)(b) our Kentucky direct capital budget for fiscal years 2025, 2026, 2027, 2028. Given that no issues have been found in the Company's past cases regarding prudency of investment, I believe removing the caps to meet current

investment plans is not unreasonable for the Company's ability to continue to provide safe and reliable service in Kentucky.

Q. ARE THE COMPANY'S PROPOSED NON-PRP FISCAL YEAR 2025 AND FISCAL 2026 PROJECTS INDIVIDUALLY INCLUDED IN THIS CASE?

A. Yes. Exhibits TRA-6 and TRA-7 provide in detail the individual project descriptions, the business purpose, and the associated regulatory requirements of each project. The Company's projects submitted for inclusion and approval in this case for FY25 and FY26 non-PRP capital investment are prudent and in the public interest for the reasons detailed within their respective exhibits.

V. ATMOS ENERGY'S REPLACEMENT PROGRAM, INCLUDING THE CHANGES PROPOSED HEREIN, IS IN THE PUBLIC INTEREST

Q. IS ATMOS ENERGY'S APPROACH TO PIPELINE REPLACEMENT THROUGH THE EXISTING PRP AND PROPOSED PM RIDER APPROPRIATE TO ADDRESS PIPELINE SAFETY AND SERVE THE PUBLIC INTEREST?

A. Yes. Inherent in the federal regulations, the integrity rules, and the associated directives, is the requirement that pipeline operators do what is reasonably necessary for the public good. The assessment, rehabilitation, and proactive modernization of infrastructure are essential to enhancing the safety and integrity of the system. As I described above, Atmos Energy is required by the PIPES Act

of 2020 to have a distribution facilities replacement program to address leak-prone pipe, including bare steel and vintage plastics such as Aldyl-A.

It is in the public interest to promote safety and investment in the integrity of our system in a systematic manner that enables diligent regulatory oversight in the areas of both safety regulation and rate regulation. In addition, implementing and funding a safety and reliability program in a manner consistent with the federal requirements and directives will afford our customers and the public the continued security and benefits associated with a safe and reliable natural gas distribution system.

Q. DOES PHMSA BELIEVE THAT UTILITY RATE REGULATORS SHOULD SUPPORT PIPE REPLACEMENT PROGRAMS THROUGH THEIR RATE-SETTING AUTHORITY?

A. Yes. In fact, when PHMSA initiated the DIM rulemaking in 2008, it emphasized the importance of oversight performed directly by state regulatory bodies. PHMSA stated specifically:

> States must implement the minimum standards established by PHMSA but have a variety of ways in which they can oversee distribution pipeline safety. They can simply mirror the Federal pipeline safety program; they can impose additional requirements, beyond the Federal minimum; they can engage in special oversight programs with individual operators or groups of operators; or finally, they can provide incentives for safety improvements, often through their rate-setting authority. (emphasis added)

> It is appropriate that the principal actions for regulating distribution pipeline safety rest with the States. States need to balance safety

and affordability. They need to ensure that the particular needs of their citizenry are fulfilled....[25]

Q. HAS THE COMMISSION RECOGNIZED THE NEED FOR ACCELERATED PIPELINE REPLACEMENT IN KENTUCKY?

A. Yes. The Commission understands the importance of having a regulatory structure in place for utilities to mitigate pipeline safety risks. As mentioned previously, the Commission in Atmos Energy's 2018 rate case stated regarding pipe replacement programs:

> *The Commission has consistently found that the public interest is served by replacing potentially unsafe, aged gas pipelines through the adoption of pipeline replacement programs that have been approved as being fair, just and reasonable. To the extent that the pipeline eligible for replacement poses a safety risk to the utility's customers, service areas, and employees, the Commission reiterates that it is in favor accelerated replacement. The Commission believes that pipeline replacement programs improve public safety and reliability of service for customers…*
>
> *Through the PRP process, the Commission is able to separately review and scrutinize each project and expenditure annually, with the opportunity for the Attorney General, and potentially others, to intervene in the PRP proceedings. The Commission finds that the already established separately review for the accelerated replacement of bare steel pipelines in Atmos' system to be a more streamlined and efficient process than Atmos's proposal to include the PRP projects in an annual base rate case. During a base rate case, a multitude of issues are examined in detail by the parties and the Commission. If PRP projects are also included in the base rate case then the Commission and the intervenors may not have adequate time to review and analyze the proposed projects.*[26]

In its final Order in Case No. 2018-00086, the Commission commented specifically on Aldyl-A replacement:

[25] Notice of Proposed Rulemaking, 73 Fed. Reg. 36015 at 36017.
[26] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), Order at 14-15.

> *The Commission is aware of the risk associated with Aldyl-A pipe. As Delta states in its application, Aldyl-A is subject to slow crack growth that leads to eventual rupture of the pipe. Furthermore, Aldyl-A has been the subject of several PHMSA bulletins, the most recent of which is attached hereto as Appendix B. Due to the significant amount of pre-1983 Aldyl-A pipe that exists in the Delta system, the Commission finds that the Aldyl-A pipe should be replaced in a 15-year time frame. As of the date of this Order, the newest of the Aldyl-A pipe on Delta's system is at least 35 years old. At the conclusion of Delta's proposed PRP, the newest of the Aldyl-A pipe will be at least 50 years old. Given that Aldyl-A pipe was installed on Delta's system as early as 1965, and some has already been in service nearly 55 years, the Commission finds that now is an appropriate time to plan for the replacement of Aldyl-A pipe. The Commission expects Delta to continue to prioritize its PRP to replace pipe based on risk, and pipe in high-consequence areas, whether it be bare steel or Aldyl-A pipe.*[27]

Q. WHAT PARAMETERS OF THE PRP IS ATMOS ENERGY PROPOSING IN THIS CASE?

A. Based on the Commission's Case No. 2023-00231 PRP Order, the Company's PRP program as of now is initially targeting bare steel replacement over Aldyl-A for PRP purposes due to the risk ranking of these materials. For the reasons described below, Atmos Energy requests to transition to the a focus on the replacement of Aldyl-A and recover through the PRP once the bare steel replacement is substantially complete so that an appropriate replacement cycle for this high relative risk material can also be established.

Atmos Energy is also requesting that the Commission remove the cap on capital investment currently placed upon the PRP program. In future PRP filings, the projects identified are expected to include all bare steel and Aldyl-A over a

[27] Case No. 2018-00086 *Electronic Adjustment of the Pipe Replacement Program Rider of Delta Natural Gas Company, Inc.*, (Ky. PSC August 21, 2018) Order at pp. 3-4.

period determined to be prudent through the implementation of Atmos Energy's approved DIMP. The removal of the cap, if approved, will facilitate the complete retirement or replacement of bare steel and Aldyl-A, two material types that have been identified by PHMSA for replacement. The assessment of the likelihood of failure includes information regarding materials that are prone to failure over time from the threat of corrosion (for bare steel) and brittle cracking (for Aldyl-A).

Q. IS THERE A NEED FOR ATMOS ENERGY TO CONTINUE REPLACING PIPE IN KENTUCKY?

A. Absolutely. As this Commission recognized and acted upon by establishing the PRP for Atmos Energy and other operators, regulatory rules and directives now mean operators must more proactively identify and address threats to the integrity of the transmission and distribution systems. Atmos Energy's proposed PM Rider is an example of such a proactive measure. The data, research, and experience of the industry have provided us with invaluable information that we can use to take a systematic approach to address and mitigate relative risk ***before*** those risks mount to the level of pipeline failure. Atmos Energy's PRP mechanism and its proposed PM Rider is a prudent approach to use that industry expertise and information for the benefit of our Kentucky customers and communities.

Q. PLEASE DESCRIBE THE VARIOUS PIPE MATERIALS THAT ARE UTILIZED IN ATMOS ENERGY'S KENTUCKY GAS DISTRIBUTION SYSTEM.

A. The U.S. Department of Transportation ("DOT") uses the following categories to classify main and service line materials: steel, ductile iron, copper/wrought iron,

plastic PVC, plastic polyethylene ("PE"), plastic ABS[28], plastic other and other. Steel pipe has been used in the natural gas industry since the 1800s and the use of plastic pipes began in the 1960s. As improved materials are developed, older materials are discontinued or phased out by the industry. As a result, the Company has many miles of pipe in our distribution system in Kentucky that are made of materials that are no longer used by Atmos Energy in new natural gas pipeline construction.

Steel pipe is categorized as bare steel or coated steel. In addition, each of those categories can be further broken down as cathodically protected or unprotected. Bare steel pipe is the oldest pipe in Atmos Energy's Kentucky system. Currently there are approximately 88 miles of bare steel mains in Atmos Energy's Kentucky system.

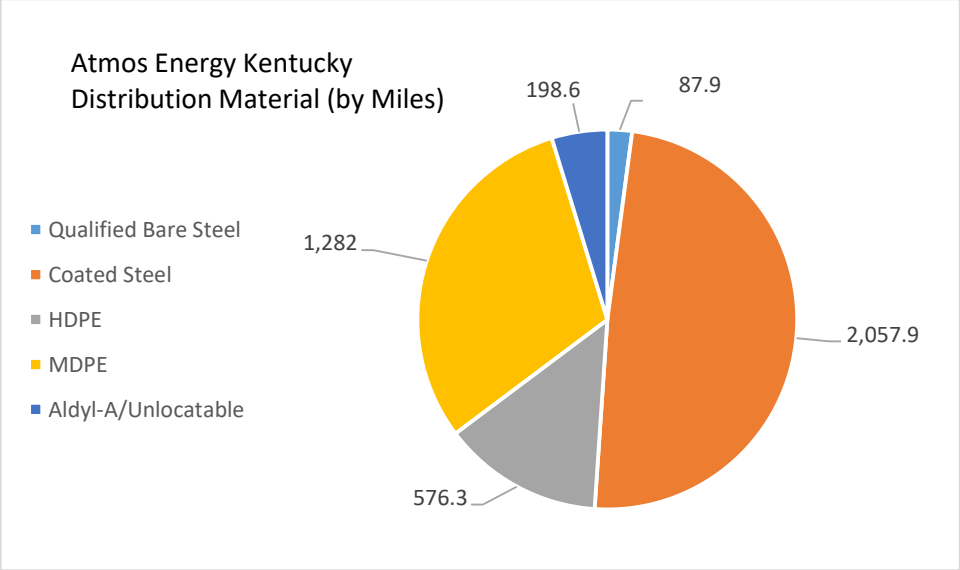
Similar to steel pipe, plastic pipe has undergone significant technological advancements over the past several decades. In Atmos Energy's Kentucky system, the early generation plastic categories consist of Aldyl-A pipe.

Aldyl-A is an early generation PE pipe installed by the natural gas industry from the 1960s through the 1980s. Technological advancements led the natural gas industry to discontinue the use of Aldyl-A and adopt medium density PE (MDPE) pipe. Currently, there are approximately 199 miles of Aldyl-A main in service in Atmos Energy's Kentucky gas distribution system.

Atmos Energy's Kentucky pipeline mains by material are shown on Table TRA-1 below:

[28] Acrylonitrile butadiene styrene.

Table TRA-1 – Atmos Energy Kentucky Distribution Pipeline by Material



Q. WHICH OF THE CATEGORIES IN TABLE TRA-1 ABOVE ARE THE PRIMARY CATEGORIES IDENTIFIED AS HIGHER RELATIVE RISK?

A. Qualified Bare Steel and Aldyl-A/Unlocatable are the two broad categories that have a higher relative risk, primarily because they have been identified as leak-prone pipe.

Q. WHAT ARE THE MAIN CAUSES OF LEAKS ON BARE STEEL PIPE?

A. The most frequent cause of leaks on bare steel pipe is corrosion. Excluding excavation damage, approximately 84% of all below ground leaks repaired on Atmos Energy's bare steel system in Kentucky over the past four years were caused by corrosion.

Q. CAN CORROSION ON BARE STEEL PIPE BE EXPECTED TO CONTINUE IN THE FUTURE?

A. Yes. Once the corrosion process has started on bare steel pipe, it will continue until the pipe fails or is replaced.

Q. DOES CATHODIC PROTECTION ELIMINATE THE DETERIORATION OF BARE STEEL PIPE?

A. No. Cathodic protection is a technique used to control the corrosion rate of a metal surface. Properly applied cathodic protection reduces the rate of corrosion but does not eliminate corrosion from occurring.

Q. WHY IS THAT A CONCERN?

A. The majority of the remaining 88 miles of Atmos Energy's bare steel pipe has been in the ground since before the 1960s. As the bare steel pipe continues to age, it deteriorates and develops leaks. Allowing bare steel pipe to remain in the ground increases the risk to public safety and the reliability of our system.

Q. WHAT TYPES OF MATERIALS IS ATMOS ENERGY USING TO REPLACE THE BARE STEEL PIPE?

A. Depending on the system maximum allowable operating pressure, Atmos Energy is replacing bare steel pipe with either High Density polyethylene ("HDPE") or coated steel pipe.

Q. IS THE BARE STEEL REPLACEMENT CONTEMPLATED IN CASE NO. 2009-00354 COMPLETE?

A. No, the Company's replacement of bare steel pipe is not complete. However, it has progressed pursuant to the schedule set by the Commission's Order in Case No. 2017-00349. As the Commission stated, "the original 15-year PRP time period should be extended and that annual ratepayer-funded PRP investment should be limited to $28 million, barring the identification of a PRP eligible pipeline-related hazard that could not have been reasonably foreseen. $28 million in annual

investment should cause the remaining PRP for bare steel replacement to be complete in 6 - 7 years with estimated completion in 2027, adding two years to the originally approved 15-year timeframe."[29] In the Company's Case No. 2023-00231 PRP filing, the Commission stated that "for the reasons discussed in previous orders, the Commission finds that Atmos's PRP investment should continue to be subject to a cap, but that it should be raised to $30 million."[30] As discussed previously, the Company noted that the order in that case raising the PRP cap to $30 million will not, in the Company's opinion, allow the Company the opportunity to meet the Commission's proposed 2027 timeline. Because of the constraints placed on the PRP Rider to date coupled with rising costs of construction, the original 2027 timeline estimate is no longer feasible, and the Company believes bare steel replacement will require additional years even if the request to lift the caps is granted. However, lifting the caps now will remove future constraints so that Atmos Energy can work towards a feasible target date for completion of this work.

Q. HOW MUCH PROGRESS HAS BEEN MADE ON THE REPLACEMENT OF BARE STEEL PURSUANT TO THE PRP?

A. By the end of CY2024, the Company will have approximately 88 miles of the original 345 miles of bare steel remaining in Kentucky.

[29] Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications* (Ky. PSC May 3, 2018), Order at 40

[30] Case No. 2023-00231, *Electronic Application of Atmos Energy Corporation to Establish PRP Rider Rates for the Twelve Month Period Beginning October 1, 2023* (Ky. PSC September 29, 2023), Order at 16.

Q. ARE DISTRIBUTION FACILITIES REPLACEMENT PROGRAMS THROUGHOUT ATMOS ENERGY CORPORATION'S EIGHT STATES LIMITED BY MATERIAL TYPE?

A. No. The Direct Testimony of Joe Christian provides an overview of the rate recovery for infrastructure replacement in the other seven states served by Atmos Energy. It is my understanding that in each of those states the Company is not strictly limited by material type and has an avenue to recover costs associated with all replacement projects to address relative risk on the system.

Q. IS THE PRP ONLY MEANT TO ADDRESS THE REPLACEMENT OF BARE STEEL?

A. It is my understanding that the statute authorizing recovery of costs of investment in natural gas pipeline replacement programs does not limit the material type eligible to be replaced.[31] The Commission did initially approve Atmos Energy's PRP Rider only for recovery of bare steel replacement projects. However, in the Commission's decision in Case No. 2021-00214 the Commission stated the inclusion of future Aldyl-A pipelines will be determined on a case-by-case basis and any PRP applications should at minimum include safety justifications for such projects.[32] The Commission also approved in that general case incremental spend of $2.794 million for Aldyl-A replacement projects in Cadiz, Kentucky.[33] In the

[31] KRS § 278.509 ("Notwithstanding any other provision of law to the contrary, upon application by a regulated utility, the commission may allow recovery of costs for investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility. No recovery shall be allowed unless the costs shall have been deemed by the commission to be fair, just, and reasonable.")
[32] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022), final Order at 60.
[33] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022), final Order at 60.

Company's 2022-00222 PRP Case, the Company proposed for inclusion two additional Aldyl-A projects in Cadiz, Kentucky, and one Aldyl-A project in St. Charles, Kentucky.[34] The Commission found those Aldyl-A projects reasonable and approved their conclusion in the Company's PRP.[35]

In the Company's most recent PRP filing, Case No. 2023-00231, the Company proposed additional Aldyl-A projects in the Cadiz, Kentucky area as well one project each in Paducah, Kentucky, and Horse Cave, Kentucky.[36] The Commission denied these Aldyl-A projects and stated that the Company did not indicate that the proposed Aldyl-A projects ranked highest on its DIMP or explain why they should be prioritized over specific projects that rank higher, including why the projects should be prioritized over higher ranking bare steel project.[37] The Commission also stated that in any future Atmos Energy PRP Application that the Company should show either that the Aldyl-A pipe segment is risk-ranked ahead of bare steel and other Aldyl-A pipe the replacement of which would be deferred due to the spending cap or that specific operational circumstances justify replacement of the Aldyl-A segment ahead of higher ranked bare steel or Aldyl-A segments.[38]

[34] Case No. 2022-00222, *Electronic Application of Atmos Energy Corporation to Establish PRP Rider Rates for the Twelve Month Period Beginning October 1, 2022* (Ky. PSC May 25, 2023) final Order at 2-3
[35] [35] Case No. 2022-00222, *Electronic Application of Atmos Energy Corporation to Establish PRP Rider Rates for the Twelve Month Period Beginning October 1, 2022* (Ky. PSC May 25, 2023) final Order at 3.
[36] Case No. 2023-00231, *Electronic Application of Atmos Energy Corporation for PRP Rider Rates Beginning October 1, 2023*, (Ky. PSC Sept. 29, 2023) final Order at 14-15.
[37] Case No. 2023-00231 *Electronic Application of Atmos Energy Corporation for PRP Rider Rates Beginning October 1, 2023*, (Ky. PSC Sept. 29, 2023) final Order at 17
[38] Case No. 2023-00231 *Electronic Application of Atmos Energy Corporation for PRP Rider Rates Beginning October 1, 2023*, (Ky. PSC Sept. 29, 2023) final Order at 18

Q. DO YOU ADVOCATE THE ACCELERATED REPLACEMENT OF MORE THAN JUST BARE STEEL?

A. Yes. As Company witnesses testified in Case Nos. 2017-00349 and 2018-00281, there are other types of pipeline materials that the industry has identified that warrant accelerated replacement. While the industry recognizes bare steel as one of the leading risk types, utilities need to have appropriate replacement cycles for all of their pipeline infrastructure so that replacement occurs ***before*** the pipeline infrastructure begins to fail.

I also note that the federal legislation and rulemaking activity described above are expected to result in further mitigation requirements as they reach their effective dates.

Q. WHAT DO YOU MEAN BY "REPLACEMENT CYCLES?"

A. In Kentucky, Atmos Energy has approximately 4,200 miles of natural gas distribution and transmission pipeline (plus associated service lines). If we were to replace 42 miles of pipe per year (1%), it would take 100 years to renew the entire system, and at the end of that 100 years we would still have a system with some segments that were 100 years old. The reality is that the age and vintage technology of our system must be taken into account to adjust our replacement rate accordingly. For example, a majority of our bare steel systems were installed in the 1930s-1950s, already making them 70-90 years old and requiring a replacement rate that is significantly more accelerated.

Q. PLEASE PROVIDE ADDITIONAL DETAIL ABOUT ATMOS ENERGY'S ALDYL-A PIPE.

A. Atmos Energy's Kentucky gas distribution system still contains approximately 199 miles of Aldyl-A pipe. While this pipe is not generally as old as the bare steel pipe in Atmos Energy's Kentucky distribution system, it is nonetheless made of legacy materials that are no longer used in the natural gas industry and have been directed by PHMSA to be targeted for replacement.

Q. WHAT ARE THE MAIN CAUSES OF LEAKS ON ALDYL-A PIPE?

A. As these materials age, the structure of the pipe weakens, becomes brittle and eventually cracks. In 2007, PHMSA issued an Advisory Bulletin ADB-07-01 for updated notification of the susceptibility of older plastic pipes to premature brittle-like cracking. The older pipes listed included Aldyl-A. The advisory bulletin noted that:

> *Brittle-like cracking refers to crack initiation in the pipe wall not immediately resulting a full break followed by stable crack growth at stress levels much lower than the stress required for yielding. This results in very tight, slit-like, openings and gas leaks. Although significant cracking may occur at point of stress concentration and near improperly designed or installed fittings, small brittle-like cracks may be difficult to detect until a significant amount of gas leaks out of the pipe, and potentially migrates into an enclosed space such as a basement.*

A copy of the Advisory Bulletin is included as Exhibit TRA-8. The brittle-like cracking characteristic could cause a leak on an early vintage plastic pipeline such as Aldyl-A to grow and release additional natural gas than would normally be released, increasing the risk of natural gas gathering and igniting.

Q. DOES PHMSA BULLETIN ADB-07-01 MAKE A DISTINCTION AMONG TYPES OF ALDYL-A PIPE?

A. Yes. PHMSA Advisory Bulletin ADB-07-01 follows up on Advisory Bulletins ADB-99-01, ADB-99-02, and ADB-02-07 and provides updated notification of the susceptibility of older plastic pipes to premature brittle-like cracking. Among older polyethylene pipe materials these included, but are not limited, to Aldyl-A manufactured before 1983. The American Gas Association has also produced a technical document that expands on the pipe manufactured between 1971 and 1983. This pipe still has issues with brittle cracking and should be replaced as well. Table TRA-2 below is a summary of the American Gas Association documents highlighting the risks of cracking associated with various types of Aldyl-A pipe:

Table TRA-2

Years of Manufacture	Pipe Resin	Relative Resistance to Slow Crack Growth	Summary Notes
1965 – 1971	Alathon® 5040	Low	Initial Product Marketed as Aldyl A*
1971 – 1983[14]	Alathon® 5043	Low[15]	Resin Improvement. Low Ductile Inner Wall (LDIW) pipe manufacturing defect ('70-72)*
1983 – 1989[17]	Alathon® 5046-C	Medium[18]	Resin Improvement-- Sold as "Improved Aldyl A"
1989 – 1992	Alathon® 5046-U	High	Resin Improvement --"Improved Aldyl A"
1992 – 1999	Alathon® 5046-O	Very High	Resin Improvement
*Note: Low Ductile Inner Wall (LDIW) manufacturing defect primarily occurring in some pipe manufactured in years 1970 through 1972 and resulting in possible lower slow crack resistance.			

Table 1. DuPont Aldyl A Pipe Resins 1965 – 1999

- **Pre-1973 Aldyl A** - Pipe installed prior to 1973, from the first two resin formulations, and including pipe having low ductile inner wall. Susceptible to brittle-like failures due to rock impingement or squeeze-off.

- **1973-1983 Aldyl A** - Aldyl A pipe manufactured from Alathon® 5043 resin, but only that pipe manufactured after 1972 and through 1983. Susceptible to brittle-like failures due to rock impingement.

- **1984 and Later Aldyl A** - Pipe manufactured from the improved Alathon® 5046-C, 5046-U and 5046-O resins.

Q. IS ATMOS ENERGY'S EXPERIENCE WITH ALDYL-A IN ITS KENTUCKY SYSTEM CONSISTENT WITH THIS INFORMATION FROM PHMSA?

A. Yes. Over the past ten years, in Kentucky leaks on Aldyl-A within our system have averaged 35% higher per 100 miles of pipe than leaks on other types of PE pipe. When compared with leaks on coated steel, the rate is over 250% higher per 100 miles of pipe.

As the Company noted in its Case No. 2021-00214 filing, and subsequent PRP filings, Atmos Energy's system in Cadiz, Kentucky is a good example of how we see the susceptibility to cracking of Aldyl-A. The Cadiz system was installed in the mid-1960s and is entirely Aldyl-A pipe. The system has had a history of leaks caused by the rocky bedding conditions impinging on the Aldyl-A pipe which has proven to lead to increased cracking. This area also has tracer wire on the pipe that has deteriorated with time which makes it difficult to locate.

Q. HAVE YOU IDENTIFIED OPERATIONAL ISSUES RELATED TO ALDYL-A THROUGHOUT YOUR SYSTEM IN KENTUCKY, IN ADDITION TO LEAKS?

A. Yes. Most of our Aldyl-A within the system is unlocatable or difficult to accurately locate due to deterioration of the type of tracer wire installed during the 1960s and 1970s. In recent years, there has been an increase in directional boring and the installation of fiber into neighborhoods throughout Kentucky. In our Mayfield and Paducah offices, the Company has needed to keep 2 to 3 technicians locating pipe and watching these contractors full time just to keep up with the demand due to the effort it takes to try to locate the pipe to try to prevent damages and potential outages for our customers.

In addition, as communities we serve within the commonwealth grew, the systems that were Aldyl-A were extended to serve the new growth areas. It has been the Company's experience that the tie-in locations for extensions on Aldyl-A pipe are more prone to develop cracking and eventually failures.

Aldyl-A tap tees in our Kentucky system also have a history of failure on the screw-on caps. The caps crack and even break off which creates leaks. The rate of failure has been substantial enough that the industry has developed electrofusion repair kits to repair or replace the caps on the tap tees. Atmos Energy is currently mitigating these risks to the extent possible through accelerated leak surveys and monitoring, but the only long-term solution is full replacement.

Q. IS REPLACEMENT OF THIS PIPE THE ONLY REMEDY?

A. Yes, replacement is the only remedy for these pipes over time. As stated above, Aldyl-A pipe is no longer used for new installations. There is no remedial action that will reverse the brittle cracking of this early generation plastic pipe.

Q. WHAT APPROACH DOES THE COMPANY INTEND TO TAKE WITH ALDYL-A REPLACEMENT?

A. The Company's initial focus is on the replacement of pre-1973 Aldyl-A replacement and Aldyl-A that has the highest relative risk ranking. Consistent with the principles of Distribution Integrity Management, the Company intends to prioritize replacement by examining the facts of the Aldyl-A sections in its system. The prioritization of replacement takes into account factors such as age of material, location of the pipe in relation to population, and relative risk from third-party damage. Based on consideration of these risk factors, the Company has identified specific sections of Aldyl-A that should be replaced over time, and under its current proposal would anticipate the longer-term replacement of the remainder of Aldyl-A in its system over a seven-to-ten-year time period through the Company's PRP mechanism following bare steel replacement subject to Commission approval.

Q. DO YOU KNOW THE VINTAGES OF ALDYL-A IN YOUR SYSTEM?

A. Yes. Please see Table TRA-3 below.

Table TRA-3

Kentucky Aldyl-A System (in miles)	
Unknown Install Year	35.1
Pre 1973	115.8
1973 to 1983	41.4
Post 1983	6.4

Q. WHY WERE ALDYL-A PROJECTS NOT INCLUDED IN CASE NO. 2024-00226, THE COMPANY'S MOST RECENT PRP FILING?

A. In the Company's previous PRP filing, Case No. 2023-00231, the Commission denied the Company's proposed Aldyl-A projects through the PRP mechanism. In

its discussion on the caps on PRP capital, the Commission stated that "[a]s noted in previous cases, the caps should not prevent Atmos from making necessary safety improvements and recovering such costs through base rates, but rather, limits the accelerated recovery of certain investments through the PRP rider, in which an accelerated review process makes discovery regarding individual projects difficult."[39] The Company is respectfully seeking Commission approval in this rate application for long-term Aldyl-A replacement through its PRP mechanism following the completion of bare steel replacement. Currently, the Company's PRP mechanism allows for the inclusion of Aldyl-A projects on a case-by-case basis per its approved tariff. The inclusion of Aldyl-A within the PRP mechanism allows for a long-term strategic approach to replace a material type identified by PHMSA for replacement and allows the Company to appropriately balance the costs towards its customers while meeting long-term identified safety needs.

The Company is focused on mitigating risk and always seeks to prioritize projects that rank highly on its risk ranking. Based on the Commission's guidance in Case No. 2023-00231, the Company will continue bare steel replacement in its PRP mechanism based on its risk ranking over Aldyl-A. However, the Company believes the focused, long-term replacement of Aldyl-A in its system, beginning with pre-1973 Aldyl-A and highest risk-ranked Aldyl-A, also needs to occur for reasons I have discussed above. The inclusion of Aldyl-A in PRP also is in keeping with past Commission statements on the need to replace the material over time as

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well as the PRP mechanism being the appropriate mechanism to do so to allow for project review.[40]

Q. ULTIMATELY, WHAT ARE THE BENEFITS TO CUSTOMERS OF THE ACCELERATED REPLACEMENT OF THIS INFRASTRUCTURE?

A. Accelerated replacement will improve system safety and reliability. Replacing the Aldyl-A pipe will also provide the opportunity to update the associated service lines and meter sets to customers' homes. This action brings furthers safety and reliability such as installing Excess Flow Valves in the new service lines to reduce the potential for gas escaping the pipe if the service line is cut or damaged, installing more section valves to be able to isolate certain parts of the system which could reduce the number of customers impacted by third party damages, as well as

[40] *See e.g.*, Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), Order at 14-15 ("The Commission has consistently found that the public interest is served by replacing potentially unsafe, aged gas pipelines through the adoption of pipeline replacement programs that have been approved as being fair, just and reasonable. To the extent that the pipeline eligible for replacement poses a safety risk to the utility's customers, service areas, and employees, the Commission reiterates that it is in favor accelerated replacement. The Commission believes that pipeline replacement programs improve public safety and reliability of service for customers…

Through the PRP process, the Commission is able to separately review and scrutinize each project and expenditure annually, with the opportunity for the Attorney General, and potentially others, to intervene in the PRP proceedings. The Commission finds that the already established separately review for the accelerated replacement of bare steel pipelines in Atmos' system to be a more streamlined and efficient process than Atmos's proposal to include the PRP projects in an annual base rate case. During a base rate case, a multitude of issues are examined in detail by the parties and the Commission. If PRP projects are also included in the base rate case then the Commission and the intervenors may not have adequate time to review and analyze the proposed projects"); *see also* Case No. 2018-00086 *Electronic Adjustment of the Pipe Replacement Program Rider of Delta Natural Gas Company, Inc.*, (Ky. PSC August 21, 2018) Order at pp. 3-4 ("The Commission is aware of the risk associated with Aldyl-A pipe. As Delta states in its application, Aldyl-A is subject to slow crack growth that leads to eventual rupture of the pipe. Furthermore, Aldyl-A has been the subject of several PHMSA bulletins, the most recent of which is attached hereto as Appendix B. Due to the significant amount of pre-1983 Aldyl-A pipe that exists in the Delta system, the Commission finds that the Aldyl-A pipe should be replaced in a 15-year time frame. As of the date of this Order, the newest of the Aldyl-A pipe on Delta's system is at least 35 years old. At the conclusion of Delta's proposed PRP, the newest of the Aldyl-A pipe will be at least 50 years old. Given that Aldyl-A pipe was installed on Delta's system as early as 1965, and some has already been in service nearly 55 years, the Commission finds that now is an appropriate time to plan for the replacement of Aldyl-A pipe. The Commission expects Delta to continue to prioritize its PRP to replace pipe based on risk, and pipe in high-consequence areas, whether it be bare steel or Aldyl-A pipe").

allowing improved up-to-date records and mapping to assist with locating and reducing third party damages.

The proposed accelerated replacement will also reduce the inconvenience to the public by taking a proactive approach to project identification and execution rather than a reactive approach. Historically, many projects are identified and executed to eliminate an immediate hazardous threat to public safety and customer reliability. Since our concern is typically a single immediate threat, we often narrowly define the project scope to quickly eliminate only that threat. This narrow approach necessitated by the immediate hazardous threat approach can lead to missed opportunities for efficiency by expanding the scope of a retirement or replacement project to include adjacent facilities that do not yet pose an immediate threat but nevertheless pose risks to the system. Expanding the PRP mechanism will facilitate Atmos Energy's replacement of bare steel and Aldyl-A pipe in an area prior to the detection of an immediate hazardous threat so each project can be more efficient in both size and scope.

VI. TORNADO RECOVERY EFFORTS

Q. WILL THE COMPANY PROVIDE THE COMMISSION AN UPDATE ON THE COMPANY'S MAYFIELD, KENTUCKY SERVICE AREA AND SURROUNDING AREAS AND THE RECOVERY EFFORTS FOLLOWING THE TORNADO EVENT IN DECEMBER 2021?

A. Yes. In the aftermath of the tornado event in December 2021 the Company immediately brought in its personnel and contractors to make the area safe. In the ensuing months following the destruction caused by the tornado, the Company

worked with the affected towns to restore safe and reliable gas service. Table TRA-4 below shows the impact and restoration activities by the Company following the tornado event.

TABLE TRA-4

City	Total Meters Off	Meters Turned Back On Total	Service Lines Retired	Main Retired	Main Installed	Services Installed
Mayfield	980	345	444	20,700’	12,800’	106
Princeton	114	34	70	0	0	3
Dawson Springs	1,200	786	203	12,300	13,600’	24
Bremen	5	0	5	0	0	0
Bowling Green	400	150	97	0	0	3
Total	**2,699**	**1,315**	**819**	**33,000’**	**26,400’**	**136**

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Timothy (Ryan) Austin, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Timothy R. Austin

STATE OF KENTUCKY

COUNTY OF DAVIESS

SUBSCRIBED AND SWORN to before me by Timothy R. Austin on this the 23 day of September, 2024.

OFFICIAL SEAL
Jeremy Don Huss
Notary Public ID No. KYNP87024
State at Large, Kentucky
My Commission Expires 3/29/28

Jeremy Huss KYNP87024
Notary Public

My Commission Expires: Mar 29th 2028

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2011–0023; Amdt. Nos. 191–26; 192–125]

RIN 2137–AE72

Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. This final rule addresses congressional mandates, National Transportation Safety Board recommendations, and responds to public input. The amendments in this final rule address integrity management requirements and other requirements, and they focus on the actions an operator must take to reconfirm the maximum allowable operating pressure of previously untested natural gas transmission pipelines and pipelines lacking certain material or operational records, the periodic assessment of pipelines in populated areas not designated as ''high consequence areas,'' the reporting of exceedances of maximum allowable operating pressure, the consideration of seismicity as a risk factor in integrity management, safety features on in-line inspection launchers and receivers, a 6-month grace period for 7-calendar-year integrity management reassessment intervals, and related recordkeeping provisions.

DATES: The effective date of this final rule is July 1, 2020. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of July 1, 2020. The incorporation by reference of ASME/ANSI B31.8S was approved by the Director of the Federal Register as of January 14, 2004.

FOR FURTHER INFORMATION CONTACT: Technical questions: Steve Nanney, Project Manager, by telephone at 713–272–2855. General information: Robert Jagger, Senior Transportation Specialist, by telephone at 202–366–4361.

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I. Executive Summary

A. Purpose of the Regulatory Action

PHMSA believes that the current regulatory requirements applicable to gas pipeline systems have increased the level of safety associated with the transportation of gas. Still, incidents continue to occur on gas pipeline systems resulting in serious risks to life and property. One such incident occurred in San Bruno, CA, on September 9, 2010, killing 8 people, injuring 51, destroying 38 homes, and damaging another 70 homes (PG&E incident). In its investigation of the incident, the National Transportation Safety Board (NTSB) found among several causal factors that the operator, Pacific Gas and Electric (PG&E), had an inadequate integrity management (IM) program that failed to detect and repair or remove the defective pipe section. PG&E was basing its IM program on incomplete and inaccurate pipeline information, which led to, among other things, faulty risk assessments, improper assessment method selection, and internal assessments of the program that were superficial and resulted in no meaningful improvement in the integrity of the pipeline system nor the IM program itself.

The PG&E incident underscored the need for PHMSA to extend IM requirements and address other issues related to pipeline system integrity. In response, PHMSA published an ANPRM seeking comment on whether IM and other requirements should be strengthened or expanded, and other related issues, on August 25, 2011 (76 FR 53086).

The NTSB adopted its report on the PG&E incident on August 30, 2011, and issued several safety recommendations to PHMSA and other entities. Several of these NTSB recommendations related directly to the topics addressed in the 2011 ANPRM and are addressed in this final rule. Also, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act) was enacted on January 3, 2012. Several of the 2011 Pipeline Safety Act's statutory requirements related directly to the topics addressed in the 2011 ANPRM and are a focus of this rulemaking.

Another incident that influenced this rulemaking was the rupture of a gas transmission pipe operated by Columbia Gas near Sissonville, WV, on December 11, 2012. The escaping gas ignited, and fire damage extended nearly 1,100 feet along the pipeline right-of-way and covered an area roughly 820 feet wide. While there were no fatalities or serious injuries, three houses were destroyed by the fire, and several other houses were damaged. The ruptured pipe was one of three in the area that cross Interstate 77, and the incident closed the highway in both directions for 19 hours until a section of thermally damaged road surface approximately 800 feet long could be replaced. Following this incident, the NTSB finalized an accident report on February 19, 2014, issuing recommendations to PHMSA to include principal arterial roadways,

including interstates, other freeways and expressways, and other principal arterial roadways as defined by the Federal Highway Administration, to the list of ''identified sites'' that establish a high consequence area (HCA) for the purposes of an operator's IM program.

On April 8, 2016, PHMSA published an NPRM to seek public comments on proposed changes to the gas transmission pipeline safety regulations (81 FR 20722). A summary of those proposed changes, and PHMSA's response to stakeholder feedback on the individual provisions, is provided below in section IV of this document (Analysis of Comments and PHMSA Response).

The purpose of this final rule is to increase the level of safety associated with the transportation of gas. PHMSA is finalizing requirements that address the causes of several recent incidents, including the PG&E incident, by clarifying and enhancing existing requirements. PHMSA is also addressing certain statutory mandates of the 2011 Pipeline Safety Act and NTSB recommendations. While the NPRM addressed 16 major topic areas, PHMSA believes the most efficient way to manage the proposals in the NPRM is to divide them into three rulemaking actions. PHMSA is finalizing the provisions in this final rule as a first step. PHMSA anticipates completing a second rulemaking to address the topics in the NPRM regarding repair criteria in HCAs and the creation of new repair criteria for non-HCAs, requirements for inspecting pipelines following extreme events, updates to pipeline corrosion control requirements, codification of a management of change process, clarification of certain other IM requirements, and strengthening IM assessment requirements.[1] A third rulemaking is expected to address requirements related to gas gathering lines that were proposed in the NPRM.[2]

B. Summary of the Major Provisions of the Regulatory Action in Question

Several of the amendments made in this rule are related to congressional legislation from the 2011 Pipeline Safety Act. The Act provides a 6-month grace period, with written notice, for the completion of periodic integrity management reassessments that otherwise would be completed no later than every 7 calendar years.[3] Another requirement is that operators explicitly consider and account for seismicity in identifying and evaluating potential threats.[4] The Act also requires operators to report exceedances of the maximum allowable operating pressure (MAOP) of gas transmission pipelines.[5] [6] PHMSA is incorporating these changes into the PSR at 49 CFR parts 190–199 in this final rule.

This rule also requires operators of certain onshore steel gas transmission pipeline segments to reconfirm the MAOP of those segments and gather any necessary material property records they might need to do so, where the records needed to substantiate the MAOP are not traceable, verifiable, and complete. This includes previously untested pipelines, which are commonly referred to as ''grandfathered'' pipelines, operating at or above 30 percent of specified minimum yield strength (SMYS). Records to confirm MAOP include pressure test records or material property records (mechanical properties) that verify the MAOP is appropriate for the class location.[7] Operators with missing records can choose one of six methods to reconfirm their MAOP and must keep the record that is generated by this exercise for the life of the pipeline. PHMSA has also created an opportunistic method by which operators with insufficient material property records can obtain such records. These physical material property and attribute records include the pipeline segment's diameter, wall thickness, seam type, grade (the minimum yield strength and ultimate tensile strength of the pipe), and Charpy V-notch toughness values (full-size specimen and based on the lowest operational temperatures),[8] if applicable or required. PHMSA considers ''insufficient'' material property records to be those records where the pipeline's physical material properties and attributes are not documented in traceable, verifiable, and complete records.

PHMSA is requiring operators to perform integrity assessments on certain pipelines outside of HCAs, whereas prior to this rule's publication, integrity assessments were only required for pipelines in HCAs. Pipelines in Class 3 locations, Class 4 locations, and in the newly defined ''moderate consequence areas'' (MCA) [9] must be assessed initially within 14 years of this rule's publication date and then must be reassessed at least once every 10 years thereafter. These assessments will provide important information to operators about the conditions of their pipelines, including the existence of internal and external corrosion and other anomalies, and will provide an elevated level of safety for the populations in MCAs while continuing to allow operators to prioritize the safety of HCAs. This action fulfills the section 5 mandate from the 2011 Pipeline Safety Act to expand elements of the IM requirements beyond HCAs where appropriate.

This rule also explicitly requires devices on in-line inspection (ILI), launcher or receiver facilities that can safely relieve pressure in the barrel before inserting or removing ILI tools, and requires the use of a device that can indicate whether the pressure has been relieved in the barrel or can otherwise prevent the barrel from being opened if the pressure is not relieved. PHMSA is finalizing this requirement in this final rule because it is aware of incidents where operator personnel have been killed or seriously injured due to pressure build-up at these stations.

C. Costs and Benefits

Consistent with Executive Order 12866, PHMSA has prepared an assessment of the benefits and costs of the final rule as well as reasonable alternatives. PHMSA estimates the annual costs of the rule to be approximately $32.7 million, calculated using a 7 percent discount rate. The costs reflect additional integrity assessments, MAOP reconfirmation, and ILI launcher and receiver upgrades.

PHMSA is publishing the Regulatory Impact Analysis (RIA) for this rule in the public docket. The table below

[1] RIN 2137–AF39.

[2] RIN 2137–AF38.

[3] 2011 Pipeline Safety Act § 5(e).

[4] 2011 Pipeline Safety Act § 29.

[5] 2011 Pipeline Safety Act § 23.

[6] MAOP means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

[7] PHMSA uses class locations throughout part 192 to provide safety margins and standards commensurate with the potential consequence of a pipeline failure based on the surrounding population. Class locations are defined at § 192.5. A Class 1 location is an offshore area or a class location unit with 10 or fewer buildings intended for human occupancy. A Class 2 location is a class location unit with more than 10 but fewer than 46 buildings intended for human occupancy. A Class 3 location is a class location unit with 46 or more buildings intended for human occupancy, and a Class 4 location is where buildings with 4-or-more stories above ground are prevalent.

[8] A Charpy V-notch impact test and its values indicate the toughness of a given material at a specified temperature and is used in fracture mechanics analysis.

[9] A MCA is defined in § 191.3 as an onshore area within a potential impact circle, as that term is defined in § 192.903, containing either (1) 5 or more buildings intended for human occupancy or (2) any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1.*

provides a summary of the estimated costs for the major provisions in this rulemaking (see the RIA for further detail on these estimates). PHMSA finds that the other final rule requirements will not result in incremental costs. PHMSA did not quantify the cost savings from material properties verification under the final rule compared to existing regulations. PHMSA also elected to not quantify the benefits of this rulemaking and instead discusses them qualitatively. PHMSA estimated total annual costs of the rule of $31.4 million using a 3 percent discount rate, and $32.7 million using a 7 percent discount rate.

SUMMARY OF ANNUALIZED COSTS, 2019–2039

[$2017 thousands]

Provision	Annualized cost	
	3% Discount rate	7% Discount rate
1. MAOP Reconfirmation & Material Properties Verification	$25,848	$27,899
2. Seismicity	0.00	0.00
3. Six-Month Grace Period for Seven Calendar-Year Reassessment Intervals	0.00	0.00
4. In-Line Inspection Launcher/Receiver Safety	27.4	37.5
5. MAOP Exceedance Reports	0.00	0.00
6. Strengthening requirements for assessment methods	0.00	0.00
7. Assessments outside HCAs	5,482	4,713
8. Related Records Provisions	0.00	0.00
Total	31,357	32,650

II. Background

A. Detailed Overview

Introduction

Recent significant growth in the nation's production and use of natural gas is placing unprecedented demands on the Nation's pipeline system, underscoring the importance of moving this energy product safely and efficiently. Changing spatial patterns of natural gas production and use and an aging pipeline network has made improved documentation and data collection increasingly necessary for the industry to make reasoned safety choices and for preserving public confidence in its ability to do so. Congress recognized these needs when passing the 2011 Pipeline Safety Act, calling for an examination of issues pertaining to the safety of the Nation's pipeline network, including a thorough application of the risk-based integrity assessment, repair, and validation system known as IM.[10]

This final rule advances the goals established by Congress in the 2011 Pipeline Safety Act and is consistent with the emerging needs of the natural gas pipeline system. This final rule also advances the important discussion about the need to adapt and expand risk-based safety practices. As some severe pipeline incidents have occurred in areas outside HCAs [11] where the application of IM principles are not required, and as gas pipelines continue to experience failures from causes that IM was intended to address, this conversation is increasingly important.

This final rule strengthens IM requirements, including to ensure operators select the appropriate inspection tool or tools to address the pertinent identified threats to their pipeline segments, and clarifies and expands recordkeeping requirements to ensure operators have and retain the basic physical and operational attributes and characteristics of their pipelines. Further, this final rule establishes requirements to periodically assess pipeline segments in locations outside of HCAs where the surrounding population is expected to potentially be at risk from an incident, which are defined in the rule as MCAs. Even though these pipeline segments are not within currently defined HCAs, they could be located in areas with significant populations. This change facilitates prompt identification and remediation of potentially hazardous defects while still allowing operators to make risk-based decisions on where to allocate their maintenance and repair resources.

Natural Gas Infrastructure Overview

The U.S. natural gas pipeline network is designed to transport natural gas to and from most locations in the lower 48 States. Approximately two-thirds of the lower 48 States depend almost entirely on the interstate transmission pipeline system for their supply of natural gas.[12] One can consider the Nation's natural gas pipeline infrastructure as three interconnected parts—gathering, transmission, and distribution—that together transport natural gas from the production field, where gas is extracted from underground, to its end users, where the gas is used as an energy fuel or chemical feedstock. This final rule applies only to gas transmission lines and does not address gas gathering or natural gas distribution infrastructure and its associated issues. Currently, there are over 300,000 miles of onshore gas transmission pipelines throughout the U.S.[13]

Transmission pipelines primarily transport natural gas from gas treatment plants and gathering systems to bulk customers, local distribution networks, and storage facilities. Transmission pipelines can range in size from several inches to several feet in diameter. They can operate over a wide range of pressures, from a relatively low 200 pounds per square inch gage (psig) to

[10] The IM regulations specify how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs that could, in the event of a leak or failure, affect high consequence areas in the United States. These areas include certain populated and occupied areas. See § 192.903.

[11] HCAs are defined at § 192.903. There are two methods that can be used to determine and HCA, the specific differences of which we do not address here. Very broadly and regardless of which method used, operators must calculate the potential impact radius for all points along their pipelines and evaluate corresponding impact circles to identify what populations are contained within each circle. Potential impact circles with 20 or more structures intended for human occupancy, or those circles with ''identified sites'' such as stadiums, playgrounds, office buildings, and religious centers, are defined as HCAs.

[12] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–28, April 2015.

[13] U.S. DOT Pipeline and Hazardous Materials Safety Administration Data as of 4/26/2018.

over 1,500 psig. They can be hundreds of miles long, and can operate within the geographic boundaries of a single State, or cross one or more State lines.

Regulatory History

PHMSA and its State partners regulate and enforce the minimum Federal safety standards authorized by statute [14] and codified in the PSR for jurisdictional [15] gas gathering, transmission, and distribution systems.

Federal regulation of gas pipeline safety began in 1968 with the creation of the Office of Pipeline Safety and the passage of the Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90–481). The Office of Pipeline Safety issued interim minimum Federal safety standards for gas pipeline facilities and the transportation of natural and other gas by pipeline on November 13, 1968, and subsequently codified broad-based gas pipeline regulations on August 19, 1970 (35 FR 13248). The PSR were revised several times over the following decades to address different aspects of natural gas transportation by pipeline, including construction standards, pipeline materials, design standards, class locations, corrosion control, and MAOP.

In the mid-1990s, following models from other industries such as nuclear power, PHMSA started to explore whether a risk-based approach to regulation could improve safety of the public and reduce damage to the environment. During this time, PHMSA found that many operators were performing forms of IM that varied in scope and sophistication but that there were no uniform standards or requirements.

PHMSA began developing minimum IM regulations for both hazardous liquid and gas transmission pipelines in response to a hazardous liquid accident in Bellingham, WA, in 1999 that killed 3 people and a gas transmission incident in Carlsbad, NM, in 2000 that killed 12. PHMSA finalized IM regulations for gas transmission pipelines in a 2003 final rule.[16] The IM regulations are intended to provide a structure to operators to focus resources on improving pipeline integrity in the areas where a failure would have the greatest impact on public safety. The IM final rule accelerated the integrity assessment of pipelines in HCAs, improved IM systems, and improved the government's ability to review the adequacy of IM plans.

The IM regulations require that operators conduct comprehensive analyses to identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs. Approximately 7 percent of onshore gas transmission pipeline mileage is located in HCAs.[17] PHMSA and State inspectors review operators' IM programs and associated records to verify that the operators have used all available information about their pipelines to assess risks and take appropriate actions to mitigate those risks.

Since the implementation of the IM regulations, sweeping changes in the natural gas industry have caused significant shifts in supply and demand, and the Nation's pipeline network faces increased pressures from these changes as well as from the increased exposure caused by a growing and geographically dispersing population. Also, long-identified pipeline safety issues, some of which IM set out to address, remain problems. A records search following the PG&E incident required by Congress in the 2011 Pipeline Safety Act, showed that some pipeline operators do not have the records they need to substantiate the current MAOP of their pipelines, as required under existing regulations, and lacked other critical information needed to properly assess risks and threats and perform effective IM.[18] PHMSA's inspection experience indicates pipelines continue to be vulnerable to failures stemming from outdated construction methods or materials. Finally, some severe pipeline incidents have occurred in areas outside HCAs where the application of IM principles is not required.

Following the significant pipeline incident in 2010 at San Bruno, CA, in which 8 people died and more than 50 people were injured, Congress charged PHMSA with improving the IM regulations. Additionally, the NTSB and Government Accountability Office (GAO) issued recommendations regarding IM.[19] Comments in response to a 2011 ANPRM on these and related topics suggested there were many common-sense improvements that could be made to IM, as well as a clear need to extend certain IM provisions to pipelines outside of HCAs that were not covered by the IM regulations. A large portion of the transmission pipeline industry has voluntarily committed to extending certain IM provisions to non-HCA pipe, which demonstrates a common understanding of the need for this strategy.

Through this final rule, PHMSA is making improvements to IM and is improving the ability of operators to engage in a long-range review of risk management and information needs, while also accounting for a changing landscape and a changing population.

Supply Changes

The U.S. natural gas industry increased production dramatically between 2005 and 2017, from 19.5 trillion cubic feet per year to 28.8 trillion cubic feet per year.[20] This growth was enabled by the production of ''unconventional'' natural gas supplies using improved technology to extract gas from low permeability shales. The increased use of directional drilling [21] and improvements to a long-existing industrial technique—hydraulic fracturing,[22] which began as an experiment in 1947—made the recovery of unconventional natural gas easier and economically viable. This has led to decreased prices and increased use of natural gas, despite a reduction in the production of conventional natural gas of about 14 billion cubic feet per day. Unconventional shale gas production now accounts for nearly 70 percent of overall gas production in the U.S.

Growth in unconventional natural gas production has shifted production away from traditionally gas-rich regions towards inland shale gas regions. To illustrate, in 2004, wells in the Gulf of Mexico's produced 5,066,000 million

[14] Title 49, United States Code, Subtitle VIII, Pipelines, Sections 60101, *et. seq.*

[15] Typically, onshore pipelines involved in the ''transportation of gas''—see 49 CFR 192.1 and 192.3 for detailed applicability.

[16] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines).'' 68 FR 69778; December 15, 2003. Corrected April 6, 2004 (69 FR 18227) and May 26, 2004 (69 FR 29903).

[17] Per PHMSA's 2018 Annual Report, accessed April 9, 2019, 20,435 of the 301,227 miles of gas transmission pipelines are classified as being in HCAs.

[18] An effective IM program requires operators to analyze many data points regarding threats to their systems in addition to pipe attributes, including, but not limited to, construction data (year of installation, pipe bending method, joining method, depth of cover, coating type, pressure test records, etc.), operational data (maximum and minimum operating pressures, leak and failure history, corrosion monitoring, excavation data, corrosion surveys, ILI data, etc.).

[19] More information on the NTSB recommendations being addressed in this rule are discussed in further detail in Section II. D. of this document ''National Transportation Safety Board Recommendations.'' See also, GAO–06–946, Natural Gas Pipeline Safety: Integrity Management Benefits Public Safety, but Consistency of Performance Measures Should be Improved,'' September 8, 2006.

[20] U.S. Department of Energy, Energy Information Administration, ''U.S. Natural Gas marketed Production'' *https://www.eia.gov/dnav/ng/hist/n9050us2a.htm,* accessed 6/28/18.

[21] Directional drilling is the practice of drilling non-vertical wells.

[22] The extraction of oil or gas deposits performed by forcing open fissures in subterranean rocks by introducing liquid at high pressures.

cubic feet of natural gas per year (Mcf/year), approximately 20 percent of the Nation's natural gas production at the time. By 2016, that number had fallen to 1,220,000 Mcf/year, and approximately 4 percent of natural gas production in the U.S. During that same period, Pennsylvania's share of production grew from 197,217 Mcf/year to 5,463,783 Mcf/year, or approximately 17 percent of total natural gas production in the U.S.[23] [24] An analysis conducted by the Department of Energy's Office of Energy Policy and Systems Analysis projects that the most significant increases in production through 2030 will occur in the Marcellus and Utica Basins in the Appalachian Basin,[25] and natural gas production is projected to grow from the 2015 levels of 66.5 Bcf/d to more than 93.5 Bcf/d.[26]

Demand Changes

The increase in domestic natural gas production has led to lower average natural gas prices.[27] In 2004, the outlook for natural gas production and demand growth was weak. Monthly average spot prices at Henry Hub [28] were high based on historic comparison of prices, fluctuating between $4 per million British thermal units (Btu) and $7 per million Btu. Prices rose above $11 per million Btu for several months in both 2005 and 2008.[29] Since 2008, after production shifted to onshore unconventional shale resources, and price volatility fell away following the Great Recession, natural gas has traded between about $2 per million Btu and $5 per million Btu.[30]

These low prices have fueled consumption growth and changes in markets and spatial patterns of consumption. A shift towards natural gas-fueled electric power generation, cleaner than other types of fossil fuels, is helping to serve the needs of the Nation's growing population, and increased gas production and lower domestic prices have created opportunities for international export.

Plentiful domestic natural gas supply and comparatively low natural gas prices have changed the economics of electric power markets.[31] To accommodate recent growth and expected future growth in natural gas-fueled power, changes in pipeline infrastructure will be needed, including flow reversals of existing pipelines; additional lines to gas-fired generators; looping of existing networks, where multiple pipelines are laid parallel to one another along a single right-of-way to increase the capacity of a single system; and, potentially, new pipelines as well.

Increasing Pressures on the Existing Pipeline System Due to Supply and Demand Changes

Despite the significant increase in domestic gas production and the widespread distribution of domestic gas demand, significant flexibility and capacity in the existing transmission system mitigates the level of pipeline expansion and investment required. Some of the new gas production is located near existing or emerging sources of demand, which reduces the need for additional natural gas pipeline infrastructure. In many instances where new natural gas transmission capacity is needed, the network is being expanded by pipeline investments to enhance network capacity on existing lines rather than increasing coverage through new infrastructure. Additionally, operators have avoided building new pipelines by increasing pipeline diameters or operating pressures. In short, the nation's existing pipeline system is facing the brunt of this dramatic increase in natural gas supply and the shifting energy needs of the country.

In cases where use of the existing pipeline network is high, the next most cost-effective solution is to add capacity to existing lines via compression.[32] Compression requires infrastructure investment in the form of more compressor stations along the pipeline route, but it can be less costly, faster, and simpler for market participants in comparison to building a new pipeline. Adding compression, however, raises pipeline operating pressures and can expose previously hidden defects.

New pipeline projects have been proposed to address pending supply constraints and higher prices. However, gaining public acceptance for natural gas pipeline construction has proved to be a substantial challenge. Pipeline expansion and construction projects often face significant challenges in determining feasible right-of-ways and developing community support for the projects.

Data Challenges

Operators and regulators must have an intimate understanding of the threats to, and operations of, their entire pipeline system. Data gathering and integration are important elements of good IM practices, and while operators have made many strides over the years to collect more and better data, several data gaps still exist. Ironically, the comparatively positive safety record of the Nation's gas transmission pipelines to date makes it harder to quantify some of these gaps. Over the 20-year period of 1998–2017, transmission facilities accounted for 50 fatalities and 179 injuries, or about one-sixth to one-seventh of the total fatalities and injuries caused by natural gas pipeline incidents in the U.S.[33] Given the relatively limited number of significant incidents that occur, it can be challenging to project the possible impact of low-probability but high-consequence events. See the RIA included in the public docket for a more detailed analysis of key types of incidents that may be mitigated by this final rule.

On September 9, 2010, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline owned and operated by PG&E ruptured in a residential area of San Bruno, CA. The natural gas that was released subsequently ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.

The PG&E incident exposed several problems in the way data on pipeline conditions is collected and managed, showing that the operator had inadequate records regarding the physical and operational characteristics of their pipelines. These records are necessary for the correct setting and validation of MAOP, which is critically

[23] U.S. Department of Energy, Energy Information Administration, ''Gulf of Mexico—Offshore Natural Gas Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/na1060_r3fmtf_2a.htm,* accessed 6/28/18.

[24] U.S. Department of Energy, Energy Information Administration, ''Pennsylvania Natural Gas Gross Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/n9010pa2a.htm,* accessed 6/28/18.

[25] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–28, April 2015.

[26] *Id.,* at NG–6.

[27] *Id.,* at NG–11.

[28] Henry Hub is a Louisiana natural gas distribution hub where conventional Gulf of Mexico natural gas can be directed to gas transmission lines running to different parts of the country. Gas bought and sold at the Henry hub serves as the national benchmark for U.S. natural gas prices. (*Id.,* at NG–29, NG–30).

[29] Energy Information Administration, Natural Gas Spot and Futures Prices, *http://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm,* retrieved August 2018.

[30] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–11, April 2015.

[31] *Id.,* at NG–9.

[32] Gas can be reduced in volume by increasing its pressure. Therefore, operators can pack more gas into their lines if they can increase the pressure of the gas being transported.

[33] PHMSA, Pipeline Incident 20-Year Trends, *http://www.phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends.*

important for providing an appropriate margin of safety to the public.

Much of operator data is obtained through the assessments and other safety inspections required by IM regulations. However, this testing can be expensive, and the approaches to obtaining data that are most efficient over the long term may require significant upfront costs to modernize pipes and make them suitable for automated inspection. As a result, there continue to be data gaps that make it hard to fully understand the risks to and the integrity of the Nation's pipeline system.

To evaluate a pipeline's integrity, operators generally choose between three methods of testing a pipeline: Inline inspection (ILI), pressure testing, and direct assessment (DA). In 2017, PHMSA estimates that about two-thirds of gas transmission interstate pipeline mileage was suitable for ILI, compared to only about half of intrastate pipeline mileage, and therefore, intrastate operators use more pressure testing and DA than interstate operators.

ILIs are performed using tools, referred to as ''smart pigs,'' which are usually pushed through a pipeline by the pressure of the product being transported. As the tool travels through the pipeline, it identifies and records potential pipe defects or anomalies. Because these tests can be performed with product in the pipeline, the pipeline does not have to be taken out of service for testing to occur, which can prevent excessive cost to the operator and possible service disruptions to consumers. Further, unlike pressure testing, ILI does not risk destroying the pipe, and it is typically less costly to perform on a per-unit basis than other assessment methods.

Pressure tests, also known as hydrostatic tests, are used by pipeline operators as a means to determine the integrity (or strength) of the pipeline immediately after construction and before placing the pipeline in service, as well as periodically during a pipeline's operating life. In a pressure test, water or an alternative test medium inside the pipeline is pressurized to a level greater than the normal operating pressure of the pipeline. This test pressure is held for a number of hours to ensure there are no leaks in the pipeline.

Direct assessment is the visual evaluation of a pipeline at a sample of locations along the line to detect corrosion threats, dents, and stress corrosion cracking of the pipe body and seams. In general, corrosion direct assessments are carried out by performing four steps. Operators will review records and other data, then inspect the pipeline through assessments that do not require excavation or use mathematical models and environmental surveys to find likely locations on a pipeline where corrosion is most likely to occur. For external corrosion, operators must use two or more complementary indirect assessment tools, including, for example, close interval surveys, direct current voltage gradient surveys, and alternating current voltage gradient surveys, to determine potential areas of corrosion to examine. For internal corrosion, operators must analyze data to establish whether water was present in the pipe, determine the locations where water would likely accumulate, and provide for a detailed examination and evaluation of those locations. Areas identified where corrosion may be occurring are then excavated, examined visually, and remediated as necessary. Operators also perform a post-assessment on segments where corrosion direct assessments are used to evaluate the effectiveness of the technique and determine re-assessment intervals as needed.[34]

For cracking, operators collect and analyze data to determine whether the conditions for stress corrosion cracking are present, prioritize potentially susceptible segments of pipelines, and select specific sites for examination and evaluation. A DA would then evaluate the presence of stress corrosion cracking and determine its severity and prevalence. Operators are required to repair anomalies, if found, and determine further mitigation requirements as necessary.

Direct assessment can be prohibitively expensive to use on a wide scale and may not give an accurate representation of the condition of lengths of entire pipeline segments when the high expense leads the operator to select an insufficient number of observations. Further, as DA can only be used to validate specific threats, an operator that relies solely on a DA without performing a thorough risk analysis or running multiple tools specific to multiple threats might be leaving other threats unremediated in their pipelines.

Ongoing research and industry response to the ANPRM[35] and NPRM[36] indicate that ILI and spike hydrostatic pressure testing[37] is more effective than DA for identifying pipe conditions that are related to stress corrosion cracking defects. Regulators and operators agree that improving ILI methods as an alternative to hydrostatic testing is better for risk evaluation and management of pipeline safety. Hydrostatic pressure testing can result in substantial costs, occasional disruptions in service, and substantial methane emissions due to the routine evacuation of natural gas from pipelines prior to tests. Further, many operators prefer not to use hydrostatic pressure tests because it can be destructive.[38] ILI testing can obtain data along a pipeline not otherwise obtainable via other assessment methods, although this method also has certain limitations.[39]

This final rule expands the range of permissible assessment methods and incorporates new guidelines to help operators in the selection of appropriate assessment methods. Promoting the use of ILI technologies, combined with further research and development by PHMSA as well as stakeholders to make ILI testing more accurate, is expected to drive innovation in pipeline integrity testing technologies that leads to improved safety and system reliability through better data collection and assessment.

Flow Reversals, Product Changes, and Manufacturing Defects

Significant growth of production outside the Gulf Coast region—especially in Pennsylvania and Ohio[40]—is causing a reorientation of the Nation's transmission pipeline network. The most significant of these changes will require reversing flows on pipelines to move gas from the Marcellus and Utica shale formations to the southeastern Atlantic region and the Midwest.

Reversing a pipeline's flow can cause added stress on the system due to changes in gas pipeline pressure and temperature, which can increase the risk

[34] See PHMSA's fact sheet on DA at *https://primis.phmsa.dot.gov/Comm/FactSheets/FSdirectAssessmentGas.htm.*

[35] ''Pipeline Safety: Safety of Gas Transmission Pipelines—Advanced Notice of Proposed Rulemaking,'' 76 FR 5308; August 25, 2011.

[36] ''Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines,'' 81 FR 20722; April 8, 2016.

[37] A ''spike'' hydrostatic pressure test is typically used to resolve cracks that might otherwise grow during pressure reductions after hydrostatic tests or as the result of operational pressure cycles.

[38] National Transportation Safety Board, ''Pacific Gas and Electric Company; Natural Gas Transmission Pipeline Rupture and Fire; San Bruno, California; September 9, 2010,'' *Pipeline Accident Report NTSB/PAR–11–01,* Page 96, 2011.

[39] For example, ILI tools are ideal for gathering certain information about the physical condition of the pipe, including corrosion, deformations, or cracking. However, ILI technology cannot reliably detect other conditions, such as coating damage or environmental issues.

[40] U.S. Energy Information Administration, ''Annual Energy Outlook 2019,'' p. 78—Dry shale gas production by region. *https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf*

Exhibit TRA-1

of internal corrosion. Occasional failures on natural gas transmission pipelines have followed operational changes that include flow reversals and product changes.[41] Operators have recently submitted proposed flow reversals and product changes on gas transmission lines. In response to this phenomenon, PHMSA issued an Advisory Bulletin in 2014 notifying operators of the potentially significant impacts such changes may have on the integrity of a pipeline and recommended additional actions operators should consider performing before, during, and after flow reversals, product changes, and conversions to service, including notifications, operations and maintenance requirements, and IM requirements.[42]

Data indicates that some pipelines are vulnerable to issues stemming from outdated construction methods or materials. Some gas transmission infrastructure was made before the 1970s using techniques that have proven to contain latent defects due to the manufacturing process. For example, pipe manufactured using low frequency electric resistance welding is susceptible to seam failure. Because these pipelines were installed before the Federal gas regulations were issued, many of those pipes were exempted from certain regulations, most notably the requirement to pressure test the pipeline segment immediately after construction and before placing the pipeline into service. A substantial amount of this type of pipe is still in service.[43] The IM regulations include specific requirements for evaluating such pipe if located in HCAs, but infrequent-yet-severe failures that are attributed to longitudinal seam defects continue to occur. The NTSB's investigation of the PG&E incident in San Bruno determined that the pipe failed due to a similar defect, a fracture originating in the partially welded longitudinal seam of the pipe. According to PHMSA's accident and incident database, between 2010 and 2017, 30 other reportable incidents were attributed to seam failures, resulting in over $18 million of reported property damage.

Protecting the Safety and Integrity of the Nation's Pipeline System Beyond HCAs

The current IM program improves pipeline operators' ability to identify and mitigate the risks to their pipeline systems. IM regulations require that operators adopt procedures and processes to identify HCAs; determine likely threats to the pipeline within the HCA; evaluate the physical integrity of the pipe within the HCA; and repair, remediate, or monitor any pipeline defects found based on severity. Because these procedures and processes are complex and interconnected, effective implementation of an IM program relies on continual evaluation and data integration.

HCAs were first defined on August 6, 2002,[44] providing concentrations of populations with corridors of protection spanning 300, 660, or 1,000 feet, depending on the diameter and MAOP of the particular pipeline.[45] In a later NPRM,[46] PHMSA proposed changes to the definition of a HCA by introducing the concept of a covered segment, which PHMSA defined as the length of gas transmission pipeline that could potentially impact an HCA.[47] Previously, only distances from the pipeline centerline related to HCA definitions. PHMSA also proposed using Potential Impact Circles (PIC), Potential Impact Zones, and Potential Impact Radii (PIR) to identify covered segments instead of a fixed corridor width. The final Gas Transmission Pipeline Integrity Management Rule, incorporating the new HCA definition using the PIR and PIC concepts, was issued on December 15, 2003.[48]

The PG&E incident in 2010 motivated a comprehensive reexamination of gas transmission pipeline safety. In response to the PG&E incident, Congress passed the 2011 Pipeline Safety Act, which directed PHMSA to reexamine many of its safety requirements, including the expansion of IM regulations for transmission pipelines.

Further, both the NTSB and the GAO issued several recommendations to PHMSA to improve its IM program and pipeline safety. The NTSB noted in a 2015 study[49] that IM requirements have reduced the rate of failures due to deterioration of pipe welds, corrosion, and material failures. However, the NTSB noted that pipeline incidents in HCAs due to other factors increased between 2010 and 2013, and the overall occurrence of gas transmission pipeline incidents in HCAs has remained stable. Since 2013 there have been an average of 9 incidents within HCAs, which is below a peak of 12 incidents per year in 2012 and 2013, but still higher than the number of incidents in 2010 and 2011. The NTSB also found many types of basic data necessary to support comprehensive probabilistic modeling of pipeline risks are not currently available.

Looking at Risk Beyond HCAs

PHMSA posed a series of questions to the public in the context of an August 25, 2011, ANPRM titled ''Safety of Gas Transmission Pipelines'' (76 FR 53086), including whether the regulations governing the safety of gas transmission pipelines needed changing. In particular, PHMSA asked whether to add prescriptive language to IM requirements, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. PHMSA sought comment on the definition of an HCA and whether additional restrictions should be placed on the use of DA as an IM assessment method. PHMSA also requested comment on non-IM requirements, including valve spacing and installation, corrosion control, and whether regulations for gathering lines needed to be modified.

PHMSA received 103 submissions containing thousands of comments in response to the ANPRM, which are summarized in more detail below. This feedback helped identify a series of proposed improvements to IM, including improvements to assessment goals such as integrity verification, MAOP verification, and material documentation; adjusted repair criteria; clarified protocol for identifying threats,

[41] On September 29, 2013, the Tesoro High Plains pipeline leaked 20,000 barrels of crude oil in a North Dakota field. The location of pressure and flow monitoring equipment had not been changed to account for the reversed flow. On March 19, 2013, Exxon's Pegasus pipeline failed; the flow on that pipeline was reversed in 2006.

[42] ''Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes, and Conversion to Service,'' *ADB PHMSA–2014–0040,* 79 FR 56121; September 18, 2014.

[43] Currently, PHMSA's data shows that roughly 168,000 of the Nation's 301,000 miles of onshore gas transmission pipelines were installed prior to the 1970 requirement for hydrostatic pressure testing. See *https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages.*

[44] ''Pipeline Safety: High Consequence Areas for Gas Transmission Pipelines,'' *Final rule,* 67 FR 50824; August 6, 2002.

[45] The influence of the existing class location concept on the early definition of HCAs is evident from the use of class locations themselves in the definition, and the use of fixed 660 ft. distances, which corresponds to the corridor width used in the class location definition. This concept was later significantly revised, as discussed later, in favor of a variable corridor width based on case-specific pipe size and operating pressure.

[46] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),'' *Notice of Proposed Rulemaking,* 68 FR 4278; January 28, 2003.

[47] HCA and PIR definitions are in 49 CFR 192.903.

[48] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),'' *Final rule,* 68 FR 69778; December 15, 2003.

[49] National Transportation Safety Board, ''Safety Study: Integrity Management of Gas Transmission Pipelines in High Consequence Areas,'' *NTSB SS–15/01,* January 27, 2015.

risk assessments and management, and prevention and mitigation measures; expanded and enhanced corrosion control; requirements for inspecting pipelines after incidents of extreme weather; and new guidance on how to calculate MAOP in order to set operating parameters more accurately and predict the risks of an incident. PHMSA published an NPRM on April 8, 2016 (81 FR 20722), which is discussed in more detail below.

Many of these aspects of IM have been an integral part of PHMSA's expectations since the inception of the IM program. As specified in the first IM rule, PHMSA expects operators to start with an IM framework, evolve a more detailed and comprehensive IM program, and continually improve their IM programs as they learn more about the IM process and the material condition of their pipelines through integrity assessments.

Section 23 of the 2011 Pipeline Safety Act required PHMSA to have pipeline operators conduct a records verification to ensure that their records accurately reflect the physical and operational characteristics of their pipelines in certain HCAs and class locations, and to confirm the established MAOP of those pipelines. Based on the data received from operators following the records verification, incidents that have occurred in non-HCA areas, and other knowledge gained since the 2011 Pipeline Safety Act was passed, PHMSA has become increasingly concerned that a rupture on the scale of San Bruno, with the potential to cause death and serious injury, as well as damage to the environment or the disruption of commerce, could occur elsewhere on the Nation's pipeline system in both HCA and non-HCA pipeline segments. There have been several recent incidents in non-HCAs that show significant incidents can occur in non-HCAs. For example, on December 14, 2007, two men were driving in a pickup truck on Interstate 20 near Delhi, LA, when a 30-inch gas transmission pipeline owned by Columbia Gulf Transmission Company ruptured. One of the men was killed, and the other was injured.

Further, on December 11, 2012, a 20-inch-diameter gas transmission line operated by Columbia Gas Transmission Company ruptured about 106 feet west of Interstate 77 (I–77) in Sissonville, WV. An area of fire damage about 820 feet wide extended nearly 1,100 feet along the pipeline right-of-way. Three houses were destroyed by the fire, and several other houses were damaged. Reported losses, repairs, and upgrades from this incident totaled over $8.5 million, and major transportation delays occurred. I–77 was closed in both directions because of the fire and resulting damage to the road surface. The northbound lanes were closed for approximately 14 hours, and the southbound lanes were closed for approximately 19 hours while the road was resurfaced, causing delays to both travelers and commercial shipping.

Finally, on April 29, 2016, an incident occurred on a Texas Eastern Transmission Corporation gas transmission line operated by Spectra Energy near Delmont, PA, which is approximately 25 miles away from Pittsburgh, PA. The explosion seriously injured one person, destroyed a house, damaged three other homes and vehicles outside, and caused the evacuation of nine other homes in the area. Even though the pipeline was in a Class 1 rural area, it still had a significant impact on the local population.

The Nation's population is growing, moving, and dispersing, leading to changes in population density that can affect the class location of a pipeline segment, as well as whether it is in an HCA. The definition of HCA is not necessarily an accurate reflection of whether an incident will have an impact on people. Requiring assessment and repair criteria for pipelines that, if ruptured, could pose a threat to areas where any people live, work, or congregate would improve public safety and would improve public confidence in the Nation's natural gas pipeline system.

Some pipeline operators have said they are already moving towards expanding the protections of IM beyond HCAs. In 2012, the Interstate Natural Gas Association of America (INGAA) issued a ''Commitment to Pipeline Safety,'' [50] underscoring its efforts towards a goal of zero incidents, a committed safety culture, a pursuit of constant improvement, and applying IM principles on a system-wide basis. To accomplish this goal, INGAA's members committed to performing actions that include applying risk management beyond HCAs; raising the standards for corrosion management; demonstrating ''fitness for service'' on pre-regulation pipelines; and evaluating, refining, and improving operators' ability to assess and mitigate safety threats. These actions aim to extend protection to people who live near pipelines but not within defined HCAs. Further, this final rule takes important steps toward developing a comprehensive approach for the entire industry by finalizing requirements for assessments outside of HCAs.

This final rule implements risk management standards that most accurately target the safety of communities while also providing sufficient ability to prioritize areas of greatest possible risk and impact.

Given the results of incident investigations, IM considerations, and the feedback from the ANPRM and the NPRM, PHMSA has determined it is appropriate to improve aspects of the current IM program and codify requirements for additional gas transmission pipelines to receive integrity assessments on a periodic basis to monitor for, detect, and remediate pipeline defects and anomalies. In addition, to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while balancing the cost of identifying such locations, PHMSA based the requirements for identifying those locations on effective processes already being implemented by pipeline operators and that protect people on a risk-prioritized basis.

Establishing integrity assessment requirements for non-HCA pipeline segments is important for providing safety to the public. Although those pipeline segments are not within defined HCAs, they will usually be in populated areas, and pipeline accidents in these areas may cause fatalities, significant property damage, or disrupt livelihoods. This final rule adopts a newly defined definition for MCAs to identify additional non-HCA pipeline segments that would require integrity assessments, thus assuring the timely discovery and repair of pipeline defects in MCA segments that could potentially impact people, property, or the environment. At the same time, operators can allocate their resources to HCAs on a higher-priority basis.

B. Pacific Gas and Electric Incident of 2010

On September 9, 2010, a 30-inch-diameter segment of a gas transmission pipeline owned and operated by PG&E ruptured in a residential neighborhood in San Bruno, CA, producing a crater approximately 72 feet long by 26 feet wide. The segment of pipe that ruptured weighed approximately 3,000 pounds, was 28 feet long, and was found 100 feet

[50] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, ''*Safety of Gas Transmission Pipelines,* Docket No. PHMSA–2011–0023.'' INGAA represents companies that operate approximately 65 percent of the gas transmission pipelines, but INGAA does not represent all pipeline operators subject to 49 CFR part 192.

south of the crater. Over the course of the incident, 47.6 million standard cubic feet of natural gas was released. The escaping gas ignited, and the resultant fire destroyed 38 homes, damaged another 70, killed 8 people, injured approximately 60 people (10 seriously), destroyed or damaged 74 vehicles, and caused the evacuation of over 300 more people. The initial 911 calls described the fire as a ''gas station explosion'' and a ''possible airplane crash.'' After 91 minutes, PG&E was able to shut off the flow of gas to the rupture site, which allowed firefighters to approach the rupture site and begin containment efforts. Firefighting operations continued for 2 days; more than 900 emergency responders from San Bruno and surrounding areas were part of the emergency response, 600 of which were firefighters and emergency medical services personnel.[51]

The NTSB, in its pipeline accident report for the incident, determined that the probable cause of the accident was PG&E's inadequate quality assurance and control when it relocated the line in 1956 and an inadequate IM program. The NTSB determined that PG&E's IM program was deficient and ineffective because it was based on incomplete and inaccurate pipeline information, did not consider the pipeline's design and materials contribution to the risk of a pipeline failure, and failed to consider the presence of previously identified welded seam cracks as part of its risk assessment. These deficiencies resulted in the selection of an examination method that could not detect welded seam defects and led to internal assessments of PG&E's IM program that were superficial and resulted in no improvements. Ultimately, this inadequate IM program failed to detect and repair or remove the defective pipe section.

The NTSB found that PG&E's inaccurate geographic information system records at the time of the incident indicated that the ruptured segment was constructed from 30-inch-diameter seamless API 5L X42 steel pipe. However, seamless pipe has never been available in 30-inch diameter. According to PG&E employees who testified during the investigation, all 30-inch pipe purchased by PG&E at that time would have been double submerged arc welded, which has been found in cases to be susceptible to weld failure. This inaccuracy was compounded with the discovery that the material code from the journal voucher that PG&E's records were originally composed from erroneously indicated the ruptured segment was X52 grade pipe (52,000 pounds per square inch (psi)), not X42 grade pipe (42,000 psi). X52 pipe has a higher minimum yield strength than X42 pipe,[52] and incorporating such values into MAOP calculations would produce values that would be inconsistent with the pipeline's actual MAOP. PG&E also could not produce any design, material, or construction specifications from the 1956 construction project. In short, no one from PG&E could reliably determine what type of pipe was in the ground that ruptured.

The NTSB also noted that PHMSA's exemption of pipelines installed before 1970 from the regulatory requirement for pressure testing, which likely would have detected the installation defects, was a contributing factor to the accident. When the initial Federal minimum safety standards for natural gas transmission pipelines were finalized in 1970, an exemption was carved out for pre-1970s pipelines from the requirement for a post-construction hydrostatic pressure test. This exemption was not proposed in any of the NPRMs that preceded the initial regulations and was based on an assertion from the Federal Power Commission [53] that ''there are thousands of miles of jurisdictional interstate pipelines installed prior to 1952,[54] in compliance with the then-existing codes, that could not continue to operate at their present pressure levels and be in compliance with [the proposed MAOP determination requirements].'' [55] Upon reviewing the operating record of interstate pipeline companies, the Commission found ''no evidence that would indicate a material increase in safety would result from requiring wholesale reductions in the pressure of existing pipelines which have been proven capable of withstanding present operating pressures through actual operation.'' The Office of Pipeline Safety, at the time, determined it ''[did] not now have enough information to determine that existing operating pressures are unsafe,'' and taking into account the statements from the Federal Power Commission, included the ''grandfather'' clause in the final rule to permit the continued operation of pipelines at the highest pressure to which the pipeline had been subjected during the 5 years preceding July 1, 1970.[56] [57] The 5-year limit was prescribed so that operators would be prevented from ''using a theoretical MAOP which may have been determined under some formula used 20, 30, or 40 years ago.'' [58]

The NTSB noted in its investigation that the ''grandfathering'' of the ruptured line resulted in missed opportunities to detect the defective pipe, as a hydrostatic pressure test to the prescribed levels for a Class 3 location would likely have exposed the defective pipe that led to the accident. Following the PG&E incident, the California Public Utilities Commission (CPUC) required PG&E and other gas transmission pipeline operators regulated by CPUC to either hydrostatically pressure test or replace certain transmission pipelines with grandfathered MAOPs, stating that gas transmission pipelines ''must be brought into compliance with modern standards for safety'' and that ''historic exemptions must come to an end.'' [59] Currently, PHMSA's data shows that roughly 168,000 of the Nation's 301,000 miles of onshore gas transmission pipelines were installed prior to the 1970 requirement for hydrostatic pressure testing.[60]

On April 1, 2014, the Department of Justice indicted PG&E for multiple criminal violations of part 192 for the 2010 incident in San Bruno, CA. The trial began on June 14, 2016, and after a 5 ½ week trial, a Federal jury found PG&E guilty of knowingly and willingly violating 5 sections of PHMSA's IM regulations and obstructing the NTSB investigation.

Specifically, with respect to the Federal Pipeline Safety Regulations, the jury found that between 2007 and 2010, PG&E knowingly and willfully failed to: (1) Gather and integrate existing data and information that could be relevant to identifying and evaluating potential threats on covered pipeline segments; (2) identify and evaluate all potential

[51] National Transportation Safety Board. 2011. *Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010.* Pipeline Accident Report NTSB/PAR–11/01. Washington, DC.

[52] 52,000 psi vs. 42,000 psi.

[53] The predecessor of the Federal Energy Regulatory Commission.

[54] Between 1935 and 1951, the B31 Code only required a pipeline be tested to a pressure of 50 psig in excess of the pipeline's proposed MAOP. The 1970 regulations required pressure testing to 125 percent in excess of the proposed MAOP.

[55] ''Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards,'' 35 FR 13248; August 19, 1970.

[56] 35 FR 13248.

[57] This requirement is currently under § 192.619(c).

[58] 35 FR 13248.

[59] ''Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans;'' California Public Utilities Commission Order; June 9, 2011.

[60] *https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages.*

threats to each covered pipeline segment; (3) include in its baseline assessment plan all potential threats on a covered segment and to select the most suitable assessment method; (4) prioritize high-risk pipeline segments for assessment where certain changed circumstances rendered the manufacturing threats on those segments unstable; and (5) prioritize pipeline segments containing low-frequency ERW pipe or other similar pipe as a high-risk segment for assessment if certain changed circumstances rendered a manufacturing seam threat on that segment unstable.

Congress required PHMSA, per the 2011 Pipeline Safety Act, to issue regulations to confirm the material strength of previously untested natural gas transmission pipelines located in HCAs and operating at a pressure greater than 30 percent of SMYS. Through this final rule, PHMSA is implementing that congressional directive and other safety measures. This final rule will improve the safety and public confidence of the Nation's onshore natural gas transmission pipeline system.

C. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM to seek public comments regarding the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines. In the 2011 ANPRM, PHMSA requested comments on 122 questions spread through 15 broad topic areas covering both IM and non-IM requirements. Among the issues related to IM that PHMSA considered included whether the definition of an HCA should be revised and whether additional restrictions should be placed on the use of certain pipeline assessment methods. PHMSA also requested comment on non-IM regulations, including whether revised requirements are needed for mainline valve spacing and actuation, whether requirements for corrosion control should be strengthened, and whether new regulations are needed to govern the safety of gas gathering lines and underground natural gas storage facilities. Based on the comments received on several of the ANPRM topics, PHMSA developed proposals for some of those topics in a NPRM that is the basis for this final rule. That NPRM and the comments received, are discussed below. PHMSA did not find it appropriate to address all the topics in a single rulemaking. Those topics that were not discussed further in the NPRM for this final rule have been discussed or will be discussed in other rulemakings.

D. National Transportation Safety Board Recommendations

On August 30, 2011, following the issuance of the ANPRM, the NTSB adopted its report on the gas pipeline incident that occurred on September 9, 2010, in San Bruno, CA. On September 26, 2011, the NTSB issued safety recommendations P–11–8 through -20 to PHMSA. Several of the NTSB's recommendations related directly to the topics discussed in the 2011 ANPRM and 2016 NPRM, and they shaped the direction of this final rule. The NTSB recommendations addressed in this final rule include:

- Exemption of Facilities Installed Prior to the Regulations. NTSB Recommendation P–11–14: *Amend Title 49 Code of Federal Regulations 192.619 to repeal exemptions from pressure test requirements and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.*''
- Pipe Manufactured Using Longitudinal Weld Seams. NTSB Recommendation P–11–15: ''*Amend Title 49 Code of Federal Regulations Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure.*''
- Incorporating interstates, highways, etc., into the list of ''identified sites'' that establish a HCA. NTSB Recommendation P–14–1: ''*Revise Title 49 CFR Section 903, Subpart O, Gas Transmission Pipeline Integrity Management, to add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined in the Federal Highway Administration's* ''*Highway Functional Classification Concepts, Criteria and Procedures*'' *to the list of* ''*identified sites*'' *that establish an HCA.*
- Increase the use of ILI tools. NTSB Recommendation P–15–20: ''*Identify all operational complications that limit the use of in-line inspection tools in piggable pipelines, develop methods to eliminate the operational complications, and require operators to use these methods to increase the use of in-line inspection tools.*''

E. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

The 2011 Pipeline Safety Act relates directly to the topics addressed in PHMSA's ANPRM of August 25, 2011, and the NPRM issued on April 8, 2016. The related topics and statutory citations include, but are not limited to:

- Section 5(e)—Allow periodic reassessments to be extended for an additional 6 months if the operator submits sufficient justification.
- Section 5(f)—Requires the expansion of IM system requirements, or elements thereof, beyond HCAs, if appropriate.
- Section 23—Requires the reporting of each exceedance of the MAOP that exceeds the build-up allowed for the operation of pressure-limiting or -control devices.
- Section 23—Requires testing to confirm the material strength of previously untested natural gas transmission pipelines and pipelines lacking records that accurately reflect the pipeline's physical and operational characteristics.
- Section 29—Requires consideration of seismicity when evaluating pipeline threats.

F. Notice of Proposed Rulemaking

On April 8, 2016, PHMSA published an NPRM seeking public comments on the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines and gas gathering pipelines (81 FR 20721).[61] When developing the NPRM, PHMSA considered the comments it received from the ANPRM and proposed new pipeline safety requirements and revisions of existing requirements in several major topic areas, including those topics addressing congressional mandates and related NTSB recommendations. A summary of the NPRM proposals and topics pertinent to this rulemaking, the comments received on those specific proposals, and PHMSA's response to the comments received is below under the ''Analysis of Comments and PHMSA Response'' section.

PHMSA determined it could more quickly move a rulemaking that focuses on the mandates from the 2011 Pipeline Safety Act by splitting out the other provisions contained in the NPRM into two other, separate rules. Promptly issuing a final rule focused on mandates will improve safety and respond to Congress, industry, and public safety groups.

[61] *https://www.regulations.gov/document?D=PHMSA-2011-0023-0118.*

As such, not all the topics from the NPRM nor the comments received on those topics are discussed as a part of this rulemaking. PHMSA intends to issue two additional final rules to address the remaining topics from the NPRM.

III. Analysis of NPRM Comments, GPAC Recommendations, and PHMSA Response

On April 8, 2016, PHMSA published an NPRM (81 FR 20722) proposing several amendments to 49 CFR part 192. The NPRM proposed amendments addressing topiic areas including verification of pipeline material properties, MAOP reconfirmation, IM clarifications, MAOP exceedance reports, ILI launcher and receiver safety, assessing areas outside of HCAs, and recordkeeping. The comment period for the NPRM ended on July 7, 2016. PHMSA received approximately 300 submissions containing thousands of comments on the NPRM. Submissions were received from groups representing the regulated pipeline industry; groups representing public interests, including environmental groups; State utility commissions and regulators; members of Congress; specific pipeline operators; and private citizens.

Some of the comments PHMSA received in response to the NPRM were comments beyond the scope or authority of the proposed regulations. The absence of amendments in this proceeding involving other pipeline safety issues (including several topics listed in the ANPRM) does not mean that PHMSA determined additional rules or amendments on those other issues are not needed. Such issues may be the subject of other existing rulemaking proceedings or future rulemaking proceedings.

The remaining comments reflect a wide variety of views on the merits of particular sections of the proposed regulations. PHMSA read and considered all the comments posted to the docket for this rulemaking.

The Technical Pipeline Safety Standards Committee, commonly known as the Gas Pipeline Advisory Committee (GPAC; the committee), is a statutorily mandated advisory committee that advises PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas pipelines.[62] The GPAC is one of two pipeline advisory committees that focus on technical safety standards that were established under the Federal Advisory Committee Act (Pub. L. 92–463, 5 U.S.C. App. 1–16) and section 60115 of the Federal Pipeline Safety Statutes (49 U.S.C. Chap. 601). Each committee consists of 15 members, with membership divided among Federal and State agencies, regulated industry, and the public. The committees consider the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

Due to the size and technical detail of this rulemaking, the GPAC met five times to discuss this rulemaking throughout 2017 and 2018.[63] During those meetings, the GPAC considered the specific regulatory proposals of the NPRM and discussed various comments made on the NPRM's proposal by stakeholders, including the pipeline industry at large, public interest groups, and government entities. To assist the GPAC in its deliberations, PHMSA presented a description and summary of the major proposals in the NPRM and the comments received on those issues. PHMSA also assisted the committee by fostering discussion and developing recommendations by providing direction on which issues were most pressing.

For the proposals finalized in this rulemaking, the committee came to consensus when voting on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the NPRM's provisions. In many instances, the committee recommended changes to certain proposals that the committee found would make certain proposals more feasible, reasonable, cost-effective, or practicable.

The substantive comments received on the NPRM as well as the GPAC's recommendations are organized by topic below and are discussed in the appropriate section with PHMSA's response and resolution to those comments.

A. Verification of Pipeline Material Properties and Attributes—§ 192.607

i.—Applicability

1. Summary of PHMSA's Proposal

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of the pipelines and to confirm the established MAOP of gas transmission pipelines. Since 2012, operators have submitted information indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP or that accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA determined that additional regulations are needed to implement this requirement of the 2011 Pipeline Safety Act. Specifically, PHMSA proposed that operators conduct tests and other actions needed to confirm and document the physical and operational characteristics for those pipeline segments where adequate records are not available, and PHMSA proposed standards for performing these actions. PHMSA sought to appropriately address pipeline risk without extending the requirement to all pipelines where risk and potential consequences are not as significant, such as pipelines in remote, sparsely-populated areas. As a result, PHMSA proposed criteria that would require material properties verification for higher-risk locations through a new § 192.607; specifically, by adding requirements for the verification of pipeline material properties for existing onshore, steel, gas transmission pipelines that are located in HCAs or Class 3 or Class 4 locations.

2. Summary of Public Comment

Several citizen and public safety groups, including Pipeline Safety Trust (PST), Pipeline Safety Coalition, National Association of Pipeline Safety Representatives (NAPSR), Coalition to Reroute Nexus, Earthworks, and The Michigan Coalition to Protect Public Rights-of-Way, supported the proposed provisions for establishing adequate material properties documentation and records. Some of these groups noted that the need for this section in the regulations would suggest poor operator implementation of the IM requirements since the inception of subpart O back in 2003.

Trade associations and pipeline industry entities were largely opposed to the material properties verification requirements for several reasons outlined below.

Many trade association and pipeline industry commenters expressed concern that the material properties verification requirements were potentially retroactive. American Petroleum Institute (API) and American Gas Association (AGA) asserted that this proposal would require operators to document and verify the material properties of existing pipelines beyond

[62] 49 U.S.C. 60115.

[63] Specifically, the GPAC met on January 11–12, 2017; June 6–7, 2017; December 14–15, 2017; March 2, 2018; and March 26–28, 2018. Information on these meetings can be found at *regulations.gov* under docket PHMSA–2011–0023 and at PHMSA's public meeting page: *https://primis.phmsa.dot.gov/meetings/*.

what was required by the regulations that were in place at the time those pipelines were put into service. These commenters stated that this retroactive requirement extends beyond the congressional authority provided to PHMSA. Several commenters, including AGL Resources, Dominion East Ohio, and New Jersey Natural Gas, expressed concern with the proposed provisions for verifying specific physical characteristics of pipelines, fittings, valves, flanges, and components for existing transmission pipelines. These stakeholders stated that it might be impossible to achieve ''reliable, traceable, verifiable, and complete'' records on a retroactive basis for existing pipelines. Some commenters, including AGA, stated that a pipeline's MAOP should be considered confirmed and there should be no need to further document material properties to verify the MAOP if operators had a pressure test record of a test conducted at 1.25 times MAOP for the pipeline segment.

Commenters also expressed concern about PHMSA's proposed new references to the material properties verification requirements under § 192.607 throughout part 192, which could be interpreted as being applicable not only to a subset of transmission pipelines but also to distribution pipelines. Commenters stated that PHMSA did not provide justification within the NPRM for applying material properties verification requirements to distribution systems, and such requirements would significantly impact distribution systems. These commenters requested that PHMSA explicitly exclude distribution pipelines from the proposed material properties verification requirements. Similarly, some commenters urged PHMSA to restrict these requirements only to gas transmission lines operating at greater than 30 percent SMYS based on the premise that lines operating below 30 percent SMYS, in most cases, tend to leak before rupture and are therefore less risky to the public. Additionally, commenters suggested that PHMSA review the various cross-references in the NPRM and eliminate those that would expand the applicability of the material properties verification requirements beyond onshore steel gas transmission pipelines in HCAs and Class 3 and Class 4 locations.

Some commenters recommended changing the size limit for small components that might trigger the material properties verification requirements from greater-than-or-equal-to 2 inches to greater-than 2 inches. A further comment on components discussed how the material properties verification provisions, as proposed, require the operator to know the weld-end bevel conditions for in-service valves and flanges. Operators noted, however, that once a weld-end is welded to a piece of pipe or other component, there is no method that can be employed to determine the condition of that bevel. Accordingly, the commenters requested this requirement be deleted or clarified. There was also a comment to delete the sampling requirement and not perform material properties verification if, when the applicable pipeline is excavated for repairs, a repair sleeve is installed. Other commenters felt that the proposed material properties verification requirements would not deliver clear, identifiable safety benefits and would lead to several unintended consequences that would decrease the integrity of pipeline systems and cause energy supply disruption. Accordingly, these commenters suggested PHMSA withdraw the proposed requirements for material properties verification.

Multiple commenters also expressed concerns that the revised provisions for establishing MAOP under § 192.619, specifically the requirement for operators to maintain all records necessary to establish and document a pipeline's MAOP as long as the pipeline remains in service, would impose extensive new recordkeeping requirements applicable to operators of distribution pipelines, including retroactive recordkeeping requirements. Commenters requested that PHMSA clarify that the new recordkeeping requirements in § 192.619(f) are applicable only to gas transmission pipelines.

Pipeline industry entities also provided comments on the relationship of the material properties verification requirements in § 192.607 and the MAOP reconfirmation requirements in § 192.624. The Gas Piping Technology Committee (GPTC) suggested that the proposed material properties verification requirements be revised to include an option of using the provisions of § 192.619(a)(1) for establishing MAOP when traceable, verifiable, and complete material property records are not available for calculating design pressure. Similarly, commenters suggested operators should be allowed to establish design yield strengths for unknown pipe grade as described at § 192.107(b)(1). Xcel Energy also stated that if an operator has previously established MAOP as per the § 192.619(a)(2) strength test requirements or will do so per the proposed § 192.624 methodology for pressure test or pressure reduction, the verification of pipeline material proposed in § 192.607 is not necessary for the purpose of ensuring safe operation.

Over the course of the meetings on June 7, 2017, and December 14, 2017, the GPAC had a robust discussion regarding the applicability of the material properties verification requirements. More specifically, the GPAC discussed the fact that two separate activities drive the need for material properties verification: (1) MAOP reconfirmation for pipelines lacking traceable, verifiable, and complete records to support the pipeline's current MAOP; and (2) the application of IM principles, especially where anomaly response and remediation calculations are concerned. The GPAC believed these aspects needed to be addressed separately in the final rule.

Subsequently, on December 14, 2017, the GPAC recommended that PHMSA modify the proposed rule by removing the applicability criteria of the material properties verification requirements and make material properties verification a procedure for obtaining missing or inadequate records or otherwise verifying pipeline attributes if and when required by MAOP reconfirmation requirements or by other code sections. In discussing the issue, the GPAC recognized that the broad applicability of the material properties verification requirements in the proposed rule was PHMSA's attempt to address the issue of inadequate records for MAOP verification, IM requirements and standard pipeline operations. The GPAC believed amending the proposed rule to remove the proposed applicability and instead explicitly refer back to the material properties verification requirements, when needed, in various regulatory sections, would more closely follow Congress' direction in the 2011 Pipeline Safety Act.

This change would also obviate the need for operators to create a material properties verification program plan per the originally proposed requirements, so the GPAC recommended PHMSA remove that requirement from the rule. Further, the committee recommended during a later meeting that PHMSA consider modifying the rule in both §§ 192.607 and 192.619 to clarify that the material properties verification requirements apply to onshore steel gas transmission lines and not to distribution or gathering pipelines.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the scope and requirements for

reconfirming the material properties of pipelines with unknown or undocumented properties. PHMSA agrees that the need for this rule is caused, in part, by poor implementation of existing IM requirements. However, PHMSA disagrees that the requirements would not deliver safety benefits or would lead to decreased integrity of pipeline systems and cause energy supply disruption. The basic knowledge of pipeline material properties is essential to pipeline safety.

PHMSA disagrees that material properties verification is not needed if the pipeline segment has been pressure tested to 1.25 times MAOP. Other reasons for needing documented, confirmed material properties (*e.g.,* wall thickness, yield strength, and seam type) include IM program requirements, implementation of pipe repair criteria and determination of the design pressure of the pipeline segment. This rule supplements existing IM requirements by providing operators a method to reconfirm material properties without necessarily performing destructive testing of the pipe material. Operators can use this method in their IM programs, to reconfirm MAOP where needed, to implement repair requirements, and to otherwise comply with part 192 where necessary. Indeed, PHMSA hopes that operators will use this method for material properties verification even when not specifically required by part 192 because it provides a common-sense, opportunistic, and practical approach for gathering the records necessary to substantiate safe MAOPs, properly implement IM, and otherwise ensure the safe operation of the nation's pipeline network.

PHMSA also disagrees that material properties verification is only needed for pipeline segments operating at pressure greater than 30 percent of SMYS. IM requirements apply to all gas transmission pipeline segments in HCAs, including those that operate at less than 30 percent of SMYS. Moreover, the gas transmission subpart O integrity management regulations at § 192.917(b), *Data gathering and integration,* require operators to gather pipe attributes including pipe wall thickness, diameter, seam type and joint factor, manufacturer, manufacturing date, and material properties. These physical properties and attributes are explicitly outlined in ASME/ANSI B31.8S—2004 Edition, section 4, table 1—Data Elements for Prescriptive Pipeline Integrity Program, which is incorporated by reference in § 192.7.

PHMSA did not intend that the requirements proposed in § 192.607 would be retroactive or would apply to distribution or gathering lines. Therefore, PHMSA is clarifying the final rule to assure that the provisions finalized in § 192.607 are not retroactive [64] and apply only to transmission lines. However, PHMSA believes that operators with IM programs that are properly following subpart O, specifically § 192.917(b), should already have this pipe information.

Regarding material properties verification for non-line pipe components, PHMSA is revising this final rule to apply the requirements to components greater than 2 inches and is removing the requirement to know the weld-end bevel conditions. PHMSA agrees with the GPAC members who commented that 2-inch pipe is not used in mainline applications and need not be subject to additional regulatory requirements to maintain safety. Also, fittings and flanges will have an ANSI class rating that will confirm whether the components meet or exceed the MAOP of the pipeline, so further regulatory requirements for components under 2 inches are not necessary to maintain safety.

To further address comments and the GPAC recommendations related to the scope and applicability of the material properties verification requirements, PHMSA is modifying this final rule to address MAOP reconfirmation and material properties verification separately from the application of IM principles. PHMSA believes this change will improve the organization of the rule. PHMSA is accomplishing this by removing the applicability criteria of the material properties verification requirements and making material properties verification a procedure for obtaining records for physical pipeline properties and attributes that are not documented in traceable, verifiable, and complete records or otherwise verifying physical pipeline properties and attributes when required by MAOP reconfirmation requirements, IM requirements, repair requirements, or other code sections. This obviates the need for all operators to create a material properties verification program plan per the originally proposed requirements, so PHMSA is removing that requirement from the rule as well. Instead, only operators who do not have traceable, verifiable, and complete records will be required to create such a plan.

[64] The material properties verification requirements are not retroactive as they mandate the creation and retention of records as operators execute the methodology in § 192.607 on a prospective basis. Operators who have not verified their records in accordance with this methodology before the effective date of this rule will not be subject to enforcement action based on § 192.607. After the effective date of the rule, operators with missing or inadequate records must follow the verification methodology in § 192.607.

A. Verification of Pipeline Material Properties and Attributes—§ 192.607 ii.—Method

1. Summary of PHMSA's Proposal

The conventional method for determining the properties of unknown steel pipe material is to cut test specimens known as ''coupons'' out of the pipe and perform destructive testing. Because of the large amount of pipe operators reported in Annual Report submissions for which there are unknown or inadequately documented properties, the cost of such a conventional approach would likely be onerous. Therefore, PHMSA proposed standards in § 192.607 by which operators could develop a material properties verification plan and use an opportunistic sampling technique to re-constitute and document material properties in a more cost-effective manner. More specifically, PHMSA proposed to allow operators to use recently developed technology to perform *in situ,* non-destructive examinations for determining the properties of unknown steel pipe material.

While PHMSA acknowledged in the preamble of the NPRM that such techniques may not be possible in every situation, PHMSA stated that it was aware that this option is already being widely deployed in the pipeline industry. Secondly, PHMSA proposed to allow operators to determine pipe properties at a sampling of similar locations and apply those results to the entire population of pipeline segments. PHMSA proposed to allow operators to take advantage of opportunities when the pipeline is exposed for other reasons, such as during maintenance and repair excavations, by requiring that material properties be verified whenever the pipe is exposed. This would reduce the number of excavations that might otherwise be required. Excavations are a large portion of the cost of re-constituting material properties for unknown pipe.

2. Summary of Public Comment

Several commenters suggested that the data required by the material properties verification process proposed by PHMSA can be obtained only through destructive pipe testing. These commenters asserted that the proposed requirements would lead to unnecessary service outages, increased methane emissions, and increased personnel

safety risks due to unnecessary excavation activities. Black Hills Energy stated that their pipeline system consists of mainly smaller-diameter transmission pipelines and that the proposed provisions would force them to take lines out of service to perform costly cutouts. API asserted that the expense and risk required for the excavations necessary to comply with the proposed provisions outweigh the value of obtaining and documenting material pipe properties. Some commenters suggested that it would be less costly for operators to simply replace pipe rather than obtain the material properties for pipe already in the ground. A commenter asserted that the proposed requirements would require unnecessary breaching of the pipeline coating, which is important for effective cathodic protection. API suggested that rather than requiring operators to gather documentation on material properties that may only be of marginal value for assessing pipeline safety, PHMSA should require a combination of hydrostatic pressure testing and ILI. API stated that, as opposed to the proposed rule's focus on the precise documentation of materials, this would appropriately shift the emphasis of the proposed regulations to confirming MAOP and away from material properties verification.

Several commenters stated that some of the data that PHMSA proposed operators verify is unnecessary for MAOP reconfirmation or other operational reasons. For example, the Interstate Natural Gas Association of America (INGAA) stated that several of the data elements that would need to be verified pursuant to the proposed material properties verification requirements are unnecessary for integrity management-related activities. Commenters suggested that PHMSA limit the required records to what is needed to calculate design pressure in order to determine MAOP. Commenters noted that the proposed requirements would require testing for stress corrosion cracking (SCC) in all cases, and that the requirement should be limited to only pipelines that are susceptible to SCC. Some commenters disagreed with the requirement to determine and keep a record for the chemical composition of steel transmission pipeline segments installed prior to the effective date of the final rule, suggesting that this information has not been previously required. Another commenter stated that the basis for having accurate chemical composition records is unclear. PG&E recommended that PHMSA recognize that chemical composition and manufacturing specifications provide limited information that can be used to evaluate the safety of an existing pipeline system. Piedmont Natural Gas stated that any requirement to retroactively obtain ultimate tensile strength and chemical composition is unnecessarily burdensome and detracts from the ultimate goal of pipeline safety by diverting valuable resources away from other risk-reduction efforts. A similar comment asserted there was no benefit in determining pipeline chemical compositions, as there is a high probability that many pipelines that might otherwise have adequate material documentation would fail the recordkeeping requirements because of a lack of existing chemical composition records and would subsequently be subject to the entire material properties verification process.

Pipeline industry entities also commented on the proposed sampling and testing requirements that would occur during excavations. Commenters asserted that the sampling requirements should be removed, and the number of excavations should not be specified. One commenter stated that the minimum number of excavations should be determined by the operator in their material properties verification plan and through statistical analysis aimed at achieving targeted confidence levels. Texas Pipeline Association (TPA) stated that there is no technical justification for the number of material properties tests being required at each test location by the proposed rule, and that the requirement of five tests in each circumferential quadrant for non-destructive tests and one test in each circumferential quadrant for destructive tests is unsupported in the proposal. TPA further stated that they are unaware of any indication that there is great variability in material properties within the body of a pipe, and that presently, material properties verification involves a single test per cylinder. Additionally, commenters stated this requirement could be unnecessarily costly and have a negative impact on pipeline safety, as the integrity of the pipeline would need to be compromised to perform these evaluations and a new joint of pipe would need to be welded onto the existing pipeline. Lastly, Spectra Energy Partners objected to the requirement that non-destructive testing be validated with unity plots comparing the results from non-destructive and destructive testing. They stated that this severely limits the value of non-destructive testing since the operator will have to remove samples for destructive testing to create the unity plots.

CenterPoint Energy stated that the definition of excavation is unclear, and that pipe may be excavated to a point for many operational activities, including spotting for construction safety and installing cathodic protection tests or current source wires. CenterPoint Energy stated that they do not view these types of excavations as opportunities for material properties verification data gathering because that would require the full exposure of a pipeline segment and the removal of good coating from the pipe. Another commenter suggested that confidence specifications for non-destructive testing would add significant cost due to inherently inaccurate test results.

Similarly, there were comments that encouraged consistency between the material properties verification requirements and the requirements for recordkeeping for materials, pipe design, and pipeline components. These comments suggested that inconsistencies between the documentation and the recordkeeping requirements could create scenarios where operators meet the recordkeeping requirements but do not have adequate documentation to prevent the material properties verification requirements from triggering.

Some commenters opposed the proposed requirement to obtain a ''no objection'' letter from PHMSA in order to use a new or other technology. PG&E recommended that PHMSA provide additional regulatory language to allow an operator to proceed with the new technology if a ''no objection letter'' to PHMSA is not received within 45 days prior to the planned use of technology. They stated that operators put in considerable time to set up contracts, schedule work, acquire permits, and that waiting on an approval or disapproval from PHMSA can dramatically impact schedule and costs. Further, commenters suggested that PHMSA's enforcement and regulatory procedures do not provide for ''no objection'' letters, and adding a new process that is not well-defined could cause additional confusion.

AGA proposed an alternative approach to material properties verification, MAOP reconfirmation, and integrity assessments outside of HCAs, which other pipeline industry entities supported. The approach included requiring operators to either pressure test or utilize an alternative technology that is determined to be of equal effectiveness on high-risk gas transmission pipelines that do not have

a record of a subpart J pressure test or are currently utilizing the grandfather clause for MAOP determination (§ 192.619(c)). AGA suggested a three-tiered approach that prioritized pipelines located in HCAs and operating at pressures greater than 30 percent SMYS. The approach also included the use of ILI tools on all gas transmission pipelines that are able to accommodate inspection by means of an instrumented ILI tool. The ILI tool used would be qualified to find defects that would fail a subpart J pressure test. Commenters stated that this alternative approach is simpler and would allow operators to focus resources on the areas of highest risk within pipeline systems. In conjunction with AGA's approach, commenters recommended including language that would allow the use of advanced ILI and non-destructive evaluations to comply with the proposed material properties verification requirements.

Certain commenters also suggested PHMSA provide a deadline by which operators must implement their material properties verification plan, as it was unclear in the proposal. Following committee discussion and PHMSA feedback, industry groups also recommended to allow operators to use their own statistical sampling plans when undertaking material properties verification rather than have PHMSA specify the number of samples that must be obtained.

At the GPAC meeting on December 14, 2017, the committee recommended that PHMSA modify the method for material properties verification by clarifying that operators are only required to confirm attributes pertinent to the goal of MAOP reconfirmation, integrity management, or other reasons when the material properties verification is being performed. The GPAC also recommended that PHMSA require operators keep records developed using the material properties verification method. The GPAC recommended that PHMSA retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to propose an alternative statistical approach and submit a notification to PHMSA with justification for their method. The GPAC also recommended that if operators notify PHMSA of an alternative sampling approach, and the operator does not receive an objection letter from PHMSA within 90 days of such a notification, the operator can proceed with their chosen method unless PHMSA notifies the operator that additional review time or additional information from the operator is needed for PHMSA to complete its review.

Similarly, the committee recommended PHMSA delete specified program requirements for how to address sampling failures and replace that with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. They further recommended that PHMSA require operators to notify PHMSA of the expanded sample program and establish a minimum standard that sampling programs must be based on a minimum 95 percent confidence level.

Further, the committee recommended that PHMSA retain the flexibility for operators to conduct either destructive or non-destructive tests when material properties verification is needed and requested PHMSA drop accuracy specifications but retain the requirement that any test methods used be validated and be performed with calibrated equipment. The GPAC also recommended PHMSA reduce the number of quadrants at which non-destructive evaluation tests be made from four to two.

Regarding the number of test locations and the number of excavations that must be performed, the GPAC recommended PHMSA accommodate situations where a single material properties verification test is needed (*e.g.,* additional information is needed for an anomaly evaluation/repair) and drop the mandatory requirements for testing multiple joints for large excavations. The GPAC also recommended PHMSA clarify the applicability of the requirements for developing and implementing procedures for conducting material properties verification tests on populations of undocumented or inadequately documented pipeline segments and the minimum number of excavations and tests that must be performed for those pipeline segments.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the method for material properties verification. PHMSA disagrees with implementing the alternative approach proposed by AGA, but the underlying comments of AGA and others related to having an alternative approach are discussed in this rulemaking and are addressed below. PHMSA strongly believes that knowledge of pipeline physical properties and attributes are essential for a modern IM program (see § 192.917(b)—*Data gathering and integration*) as well as effective pipeline and public safety. The PG&E incident at San Bruno, CA, was caused, in part, by PG&E mistakenly classifying the pipe that failed as seamless pipe. That pipe was welded seam pipe, and the failure occurred at a partially welded seam.

The NPRM included a list of material properties that could be confirmed using the material properties verification process. One of them in particular, steel toughness, is conventionally obtained only through destructive testing. It was not PHMSA's intent that toughness would need to be confirmed every time an operator was performing material properties verification, thus in effect requiring destructive testing for every location. Therefore, PHMSA is modifying this final rule to address toughness properties in a separate paragraph and is allowing the use of techniques that are reliable without specifying destructive testing. This is intended to accommodate new, non-destructive techniques currently under development. The new paragraph with these requirements also makes it clear that toughness is required only where needed and not necessarily in every case. PHMSA is also modifying other sections of this final rule to provide reasonably conservative default toughness values so that operators may achieve the goals of IM and MAOP reconfirmation using assumed values without the need for destructive testing. These changes will be discussed further in subsequent sections of this document.

Similarly, PHMSA is modifying the verbiage related to the listing of material properties to which the material properties verification process would apply. The clarification will make it clear that the material properties verification process only applies to the pertinent properties needed to achieve the goals of the activity for which material properties verification is needed, such as MAOP reconfirmation or IM. This avoids the potential for requiring that all properties be documented each time an operator goes out to perform material properties verification when only a subset of properties is needed.

PHMSA is also replacing the prescriptive accuracy specifications and unity plot validation for non-destructive testing with more general verbiage that requires that methods are validated and that operators account for the accuracy of the method used. This change will help accommodate new technology and techniques currently under development and avoid situations that

might require destructive testing to validate the non-destructive methods.

In response to the comments, PHMSA is relaxing the number of test points for non-destructive tests from four quadrants to two quadrants. This allows the operator to perform material properties verification on the top half of the pipe and would avoid the need to access the bottom half of the pipe when the repair or maintenance activity would not otherwise require it. PHMSA is also removing the proposed requirement to conduct material verification at multiple locations within a single large excavation based on the number of joints of line pipe exposed. PHMSA believes the methods described in this final rule will provide operators accurate material properties information without requiring more excavation activities than necessary.

In this final rule, PHMSA is modifying § 192.607 to specifically list the types of excavations where operators that need to verify material properties should seek to conduct material properties verification. This revision intends to avoid requiring operators perform the material properties verification process at partial excavations that do not expose the pipeline segment. For example, PHMSA considers excavations associated with direct examinations of anomalies to be an opportunity to perform material properties verification. Similarly, PHMSA is modifying the language to acknowledge the need to perform one-time material properties verification activities at specific locations, such as when performing repairs. An operator who has complete material documentation for a particular pipeline segment would not need to undertake the sampling program at excavations on that particular segment. The sampling program is specifically required when the operator needs to document material properties for entire segments of pipelines.

PHMSA disagrees with the removal of the number of samples needed and is maintaining the minimum standard to define the number of excavations in the sampling program as 1 per mile or 150 if the population of pipeline segments is more than 150 miles, whichever is less. However, PHMSA is modifying the rule to provide operators the option of proposing an alternative sampling program if they send a notification and justification of the alternative program to PHMSA in accordance with the new notification procedures at § 192.18. Operators may use an alternative sampling program 91 days after submitting a notification per § 192.18 to PHMSA if the operator has not received a letter of objection or a request from PHMSA for more time to review.

PHMSA is also withdrawing the expanded sampling requirements to address cases where operators identify problems in the initial sampling program. Instead, operators may use an alternative sampling approach that addresses how the operator's sampling plan will address findings that reveal physical pipeline properties and attributes that are not consistent with all available information or existing expectations or assumed physical pipeline properties and attributes used for pipeline operations and maintenance in the past. Operators taking such an approach must notify PHMSA of the adverse findings and provide PHMSA with specific details of the alternative sampling plan with a justification for such a plan in a notification to PHMSA. The alternative sampling program must be designed to achieve a 95 percent confidence level. In accordance with the new notification procedures at § 192.18, operators may use an alternative sampling plan 91 days after submitting a notification to PHMSA if the operator has not received a letter of objection or a request from PHMSA for more time to review.

In response to committee discussion, PHMSA is modifying its notification process broadly throughout part 192 to allow operators to propose using methods and technologies by notifying PHMSA in accordance with the new procedures in § 192.18. If an operator does not receive a letter of objection or a request from PHMSA for more time to review within 90 days of the notification, then the operator may use the proposed method or technology. Some committee members were concerned that some provisions throughout the NPRM would require action from PHMSA in the form of a ''no objection'' letter. Members noted that such a process can leave companies unable to proceed until PHMSA provided affirmative approval of the request. Committee members suggested that it may be more efficient and less burdensome for PHMSA to issue letters to operators only when they specifically object to proposed plans or solutions, and otherwise allow the operator to proceed as planned in the absence of such a letter. Other members were concerned that PHMSA might authorize sub-optimal plans or technologies by missing a deadline. To this end, members recommended an approach where PHMSA could request additional time for review beyond the 90-day period. PHMSA noted at the meeting that this is a similar process that is used by PHMSA for state waivers and the change should improve regulatory efficiency.

PHMSA's letter or email of objection will specify the reasons PHMSA does not approve of the proposed method or technology, while a request from PHMSA for more time to review the notification will extend the review period beyond 90 days. Further, to establish a verifiable record, it will be PHMSA's policy to send a ''no objection'' letter or email, either before or after the 90-day review period, when PHMSA does not object to an operator's proposed method or technology. PHMSA is applying this approach to other places in this rulemaking that require notifications and has created a general notification provision in subpart A of part 192.

PHMSA is modifying the recordkeeping requirement for the material properties verification provisions to avoid potential conflicts with other provisions in this rulemaking, such as MAOP reconfirmation, to clarify that operators are required to keep any records created, for the life of the pipeline, when verifying specific properties using the methods in § 192.607. These records must also be traceable, verifiable, and complete. These recordkeeping requirements are not retroactive, as they mandate the creation and retention of records as operators execute the methodology in § 192.607 on a prospective basis.

PHMSA disagrees with commenters that asked for PHMSA to establish a deadline for operators to complete the sampling programs. The opportunistic approach PHMSA proposed and retained for this final rule requires material properties verification activities to occur at excavation sites where operators are directly examining anomalies; performing *in-situ* evaluations; or are performing repairs, remediation, or maintenance. PHMSA does not expect operators to perform material properties verification for unknown pipe properties on pipeline segments exposed during one-call excavations. PHMSA has determined this approach is reasonable and will minimize the cost impacts of this final rule. A deadline for the material properties verification requirements of this rulemaking is not practical because it is impossible to forecast the rate or timing at which opportunities would arise to perform material properties verification for a given population of pipe.

Lastly, operators should have most of the required pipe information from following § 192.917(b) since subpart O of part 192 was codified over 15 years

ago in 2003. Section 192.917(b) requires operators to identify and evaluate the potential threats to pipeline segments by gathering and integrating existing data and information on the entire pipeline that could be relevant to the pipeline segment. In performing this identification and evaluation, operators must follow the requirements in ASME/ANSI B31.8S, section 4, and at a minimum gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S. The material properties needed to establish and substantiate MAOP are included in these lists.

B. MAOP Reconfirmation—§§ 192.624 & 192.632

i.—Applicability

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to require operators reconfirm MAOP for the following three categories of pipeline:

(1) Grandfathered pipe, in direct response to section 23(d) of the 2011 Pipeline Safety Act and NTSB recommendation P–11–14;

(2) Pipe for which documentation is inadequate to support the MAOP, in direct response to section 23(c) of the 2011 Pipeline Safety Act; and

(3) Pipe that has experienced a reportable in-service incident since its most recent successful subpart J pressure test due to an original manufacturing-related defect; a construction-, installation-, or fabrication-related defect; or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spots, or stress corrosion cracking.

It is important to note that a given pipeline segment for which the MAOP reconfirmation process would apply might fit into one, two, or all three of these proposed categories. For pipeline segments where records of the pipeline physical properties and attributes to substantiate the current MAOP are not documented in traceable, verifiable, and complete records, only those segments located within an HCA or a Class 3 or Class 4 location would be subject to the MAOP reconfirmation process under the NPRM.

This proposal directly correlates to section 23 of the 2011 Pipeline Safety Act and NTSB recommendation P–11–14 regarding the need for spike hydrostatic testing where in-service incidents have occurred. The NTSB recommended such testing for all pipe manufactured before 1970.

For pipeline segments where operators established the MAOP in accordance with the grandfather clause at § 192.619(c) (*i.e.,* pipeline segments where the MAOP is based upon the highest actual operating pressure records from a 5-year interval between July 1, 1965, to July 1, 1970, and where operators therefore do not have pressure test or material property records) or for segments with a history of in-service incidents caused by cracks or crack-like defects, PHMSA proposed to restrict the applicability of MAOP reconfirmation to HCAs, Class 3 or Class 4 locations, or MCAs, if the MCA segment can accommodate an ILI tool. The proposed inclusion of pipeline segments in these locations and with these traits slightly expand on the mandate contained in section 23 of the 2011 Pipeline Safety Act, which applied only to previously untested pipeline segments operating at a pressure greater than 30 percent SMYS located in an HCA.

In recommendation P–11–14, the NTSB recommended that all pipe manufactured before 1970 be subjected to a hydrostatic pressure test that would include a spike hydrostatic test, which PHMSA considered in its process for reconfirming MAOP. PHMSA's preliminary evaluation concluded that doing so may not be cost-effective, since a large amount of such pipe could be in remote locations where the likelihood of personal injury or property damage as a result of an incident would be low.

PHMSA's proposal expanded the applicability of MAOP reconfirmation beyond the minimum required by the congressional mandate to include pipe operating at less than 30 percent SMYS. In addition, the NPRM expanded the location criteria to include some non-HCA locations in the form of MCAs and Class 3 and Class 4 locations. As PHMSA proposed in the definitions section of the NPRM, MCAs are areas that, while not meeting the HCA criteria, include 5 or more persons or dwellings intended for human occupation or are otherwise locations where people congregate, including the right-of-ways of major roadways. See section H of this final rule for additional background on the MCA definition. The NPRM also specified that the MAOP reconfirmation process would apply only to MCA pipeline segments able to accommodate an ILI tool. This provision would not preclude an operator from choosing to conduct a pressure test, but it would avoid forcing operators to conduct a pressure test because the pipeline segment was not ''piggable.''

2. Summary of Public Comment

Many stakeholders provided input on the proposed provisions in § 192.624 that require MAOP reconfirmation for pipeline segments previously excluded from testing by the grandfather clause, pipeline segments without adequate documentation to substantiate the current MAOP, and pipeline segments that have experienced a reportable in-service incident.

Regarding the first criterion above, several commenters, including INGAA, AGA, and NAPSR, generally supported the provision requiring operators of pipeline segments where the MAOP was established via the grandfather clause to reconfirm the MAOP of those segments. Several of the pipeline industry trade associations and industry entities, however, did not support the proposed application of these criteria to all grandfathered pipeline segments within HCAs, Class 3 and Class 4 locations, and Class 1 and Class 2 piggable segments within MCAs. Gas Processors Association's Midstream Association (GPA) and AGA stated that while they support the congressional mandate to conduct testing to confirm the material strength of previously untested gas transmission pipelines in HCAs that operate at a pressure above 30 percent SMYS, they oppose the proposed provisions which extend to additional pipeline segments. INGAA and Washington Gas supported the applicability of MAOP reconfirmation in MCAs for pipelines operating at greater than or equal to 30 percent SMYS but disagreed with the proposed provisions that included MCA pipelines operating at less than 30 percent SMYS.

Some citizen groups, including PST, expressed concern that the proposed changes regarding the grandfather clause did not go far enough and suggested that PHMSA should fully implement the recommendations set forth by the NTSB. They stated that PHMSA should eliminate the grandfather clause given that the proposed provisions would not include the following groups of pipelines: (1) Pipelines in non-HCA areas within Class 1 and Class 2 locations; and (2) pipeline segments for which there is an inadequate record of a hydrostatic pressure test in areas newly designated as an MCA that are not capable of being assessed by an in-line tool. Conversely, Northeast Gas Association (NGA) stated that PHMSA should retain the grandfather clause as it prevents existing, historically safe, and maintained pipelines from being subjected to unwarranted requirements.

For pipeline segments where operators do not have adequate documentation to support the current MAOP and that PHMSA proposed would be subject to the new MAOP reconfirmation requirements, some commenters stated that they support the

requirement to the extent that it is consistent with the congressional mandate to reconfirm MAOP for pipeline segments with insufficient records within Class 3 and Class 4 locations and Class 1 and Class 2 HCAs. These commenters further stated that § 192.624(a)(2) within the proposed MAOP reconfirmation requirements should be revised to clarify that it applies only to those gas transmission pipeline segments in HCAs and Class 3 and Class 4 locations that were constructed and put into operation since the adoption of the Federal Pipeline Safety Regulations in 1970, stating that otherwise § 192.624(a)(2) would apply to those pipelines put into service prior to the implementation of Federal regulations where the requirement to maintain a pressure test record does not apply. Some commenters also stated that PHMSA should revise § 192.624(a) within the proposed MAOP reconfirmation requirements to make clear that operators that have used one of the proposed allowable methods for establishing MAOP in § 192.624(b) other than the pressure test method are not required to have a pressure test record to comply with the record requirements of the section. Washington Gas asserted that the MAOP reconfirmation requirements should apply to only pipeline segments in HCAs that operate at a pressure of greater than or equal to 30 percent SMYS. Other commenters, including Xcel Energy, stated that the proposed provisions should allow operator discretion regarding what constitutes a reliable, traceable, verifiable, and complete record to determine the necessary documentation to support a pressure test record and the necessary material properties for MAOP verification. Additionally, AGA recommended the deletion of the phrase ''reliable, traceable, verifiable, and complete'' from the proposed MAOP reconfirmation provisions in § 192.624(a)(2). Similarly, other commenters, including INGAA, recommended omitting ''reliable'' from the phrase and provided a suggested definition for ''traceable, verifiable, and complete.''

Lastly, with regard to the third category of applicable pipeline segments to the proposed MAOP reconfirmation requirements, many commenters either disagreed or requested clarification for the requirement that MAOP must be reconfirmed in cases where an in-service incident occurred due to a manufacturing defect listed under § 192.624(a)(1). For example, INGAA stated that an operator can evaluate such manufacturing defects more effectively through ongoing operations and maintenance activities rather than through MAOP reconfirmation, and that the defects PHMSA is concerned with are already addressed through integrity management. Similarly, Boardwalk Pipeline stated that pipelines that have experienced an in-service incident because of the listed defects in § 192.624(a)(1) should be subject to integrity management measures rather than MAOP reconfirmation. TransCanada and TPA recommended adding text to the applicability section of the MAOP reconfirmation requirements that would exclude a pipeline segment from such requirements if the operator has already acted to address the cause of the reported incident. Additionally, one commenter suggested that this requirement should apply only to pipelines in HCAs. Some commenters, including AGA and Consolidated Edison of New York (Con Ed), also requested additional time to comply with the proposed MAOP reconfirmation provisions, asserting that operators would be required to replace many of their transmission mains to comply with the new requirements because their current records would not be satisfactory. Due to the urban density and scale of the service areas of certain operators, AGA and Con Ed stated that this replacement process would take longer than the 15-year schedule provided in the rule. One commenter suggested that if the applicability criteria for pipeline segments with in-service incidents and manufacturing defects remains in the rule, it should be limited to a more contemporary time frame, such as a rolling 15-year window or those in-service incidents that have occurred since 2003. Pipeline Safety Trust, on the other hand, stated that the proposed timeframe of 15 years is too long for operators to reconfirm MAOP in HCAs and complete critical safety work, and they urged PHMSA to adopt significantly shorter timelines in the final rule.

Additionally, AGA asserted that the proposed MAOP provisions do not address how the completion plan and completion dates of the section would apply to pipelines that might experience a failure in the future and would then be subject to the proposed MAOP reconfirmation requirements, or for pipelines that are not currently located in a MCA but may be in the future. Lastly, INGAA stated that section 23 of the 2011 Pipeline Safety Act requires that PHMSA consult with the Chairman of the Federal Energy Regulatory Commission (FERC) and State regulators before establishing timeframes for the testing of previously untested pipes, and it is not evident that PHMSA has complied with this requirement.

As a general comment, several stakeholders, including AGA, Louisville Gas & Electric, New Mexico Gas Company, National Grid, NW Natural, PECO Energy, TECO Pipeline Gas, and New York State Electric and Gas (NYSEG), proposed an alternative method for MAOP reconfirmation where operators would execute two separate sets of actions that they stated could be performed simultaneously or separately. First, operators would either assess high-risk gas transmission pipelines using a pressure test or an alternative technology that is determined to be of equal effectiveness. Operators would categorize these pipelines in three tiers and schedule them for testing depending on the pipeline's SMYS and class location. Second, operators would use an ILI tool on all gas transmission pipelines, regardless of class location, that are capable of accommodating ILI tools. The ILI tool used would be qualified to find defects that would fail a subpart J pressure test. These commenters stated that this alternative methodology was necessary because the proposed provisions would create operational inefficiencies that would likely result in excessive cost and limited public benefit. In addition to providing this alternative proposal, many of these commenters provided other assorted comments on the proposed provisions.

At the GPAC meeting on March 26, 2018, the GPAC recommended that PHMSA revise the scope of the proposed MAOP reconfirmation provisions by excluding lines with previously reported incidents due to crack defects. To go along with this, the GPAC also recommended PHMSA create a new section in subpart O of part 192, the natural gas IM regulations, to address pipeline segments with crack-related incident histories. Doing these actions would eliminate the need for the proposed definitions of ''modern pipe,'' ''legacy pipe,'' and ''legacy construction techniques,'' and the impact of this is discussed later in this document.

The GPAC also recommended that the MAOP reconfirmation provisions be revised to apply to pipeline segments in HCAs or Class 3 or Class 4 locations that do not have traceable, verifiable, and complete records necessary to establish MAOP under § 192.619. Previously, the provisions were applicable to those pipeline segments without traceable, verifiable, and complete subpart J pressure test records. Similarly, the GPAC recommended that the MAOP

Exhibit TRA-1

reconfirmation provisions only apply to grandfathered pipelines in HCAs, Class 3 or Class 4 locations, or MCAs able to accommodate inspection with ILI tools, and that have MAOPs producing a hoop stress greater than or equal to 30 percent SMYS. In the NPRM, the provisions applied to all grandfathered pipelines in those locations regardless of SMYS. In making this recommendation, the GPAC also suggested PHMSA review the costs and benefits of applying the MAOP reconfirmation provisions to non-HCA Class 3 and Class 4 grandfathered pipe with MAOPs less than 30 percent SMYS.

During the meeting on March 27, 2018, the GPAC also recommended revisions to other sections related to the applicability of MAOP reconfirmation provisions, including withdrawing the proposed revisions to § 192.503, which tied general requirements of the subpart J pressure test to alternative MAOP and MAOP reconfirmation provisions, and withdrawing the proposed revisions to § 192.605(b)(5), which cross-referenced several sections related to the MAOP reconfirmation requirements to the requirements regarding an operator's procedural manuals.

The GPAC also examined the provisions related to the completion date of these actions and recommended that PHMSA revise the appropriate paragraph to account for pipelines that may be subject to these requirements in the future, such as for pipelines that are not in an HCA or Class 3 or Class 4 location now, but due to population growth or development may be in such a location in the future. More specifically, the GPAC recommended that an operator would have to complete all actions required by the MAOP reconfirmation provisions on 100 percent of their pipelines that meet the applicability requirements by 15 years after the effective date of the rule or as soon as practicable but no later than 4 years after the pipeline segment first meets the applicability conditions, whichever is later. The GPAC also recommended PHMSA consider a waiver or no-objection procedure if operators cannot meet the requirements within 4 years under this scenario.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the applicability of MAOP reconfirmation. After considering these comments and as recommended by the GPAC input, PHMSA is modifying the rule to address many of these comments.

Regarding the applicability of the new MAOP reconfirmation requirements at § 192.624, PHMSA notes that a simplistic repeal of the ''grandfather clause'' at § 192.619(c) is not practical because it applies to gathering and distribution lines. As the proposed rule was primarily focused on the safety of gas transmission pipelines, a broad repeal of the grandfather clause was not contemplated in the proposed rule. Further, a major expansion of the MAOP reconfirmation requirements beyond the scope of the congressional mandate in the 2011 Pipeline Safety Act would be costly, and the GPAC noted at the meeting on March 26, 2018, that there may be cost-benefit concerns to test all grandfathered pipelines. The GPAC recommended PHMSA analyze requiring operators to reconfirm the MAOP of all grandfathered lines, and PHMSA considered this as an alternative in the RIA.[65]

In response to the comments received and the recommendations of the GPAC, PHMSA is modifying the applicability of the MAOP reconfirmation requirements as follows: (1) The applicability related to pipeline segments with past in-service incidents is being eliminated. As commenters mentioned, operational failures are already addressed within integrity management and other subparts of part 192. Section 192.617, for example, would require an operator of a gas transmission line that had an in-service incident caused by an incorrect MAOP to determine the proper MAOP of the segment before placing it back into service. Causes of in-service failures are also already incorporated into the risk analyses required by the current IM regulations. If the cause of an incident is an incorrect MAOP, for example, then operators would be required to reconfirm it following the incident within their IM program. However, PHMSA is adding a new paragraph to strengthen the IM requirements at § 192.917(e)(6) to specifically include actions operators must take to address pipeline segments susceptible to cracks and crack-like defects. (2) PHMSA is also modifying the applicability of these requirements by specifying the MAOP reconfirmation requirements are applicable to pipeline segments that do not have the pipeline physical properties and attributes needed to establish MAOP documented in traceable, verifiable, and complete records, specifically those records required to establish and substantiate the MAOP in accordance with § 192.619(a), including those records required under § 192.517(a). More specifically, these requirements to verify MAOP would apply to such pipelines without traceable, verifiable, and complete records in HCAs and Class 3 and Class 4 locations as specified in the congressional mandate. Further, PHMSA is dropping the word ''reliable'' from the applicability section of the regulatory text to be consistent with previous PHMSA advisory bulletins on this topic.[66] (3) PHMSA is modifying the applicability of the MAOP reconfirmation provisions for ''grandfathered'' pipeline segments to pipelines with an MAOP greater than or equal to 30 percent of SMYS, as specified in the congressional mandate. In addition to these requirements applying to grandfathered pipelines in HCAs, PHMSA is retaining the MAOP reconfirmation applicability requirement for grandfathered pipeline segments in Class 3 and Class 4 locations and in piggable MCAs to address the NTSB recommendation on this topic. As per the committee's suggestion, PHMSA analyzed whether it would be feasible to make the MAOP reconfirmation requirements applicable to non-HCA Class 3 and Class 4 pipe operating below 30 percent SMYS. This analysis is presented as an alternative in the RIA for this rulemaking. Ultimately, PHMSA did not choose to include these categories of pipelines in the scope for the applicability of the MAOP reconfirmation requirements because the GPAC recommended it was cost-effective for the provision to only apply to pipe operating above 30 percent SMYS in Class 3 and 4 locations and because those pipelines present the greatest risk to safety.

With respect to the completion date, PHMSA acknowledges the comments received stating that pipeline segments could meet applicability criteria at some point in the future such that it would be difficult or impossible to meet the 15-year deadline for completion. Therefore, PHMSA agrees with the GPAC recommendation discussed above and is modifying the requirements in this final rule to include an alternative completion deadline of 4 years for pipeline segments that meet the applicability standards at some point in the future, for example for those pipeline segments that were in non-HCA locations that later become HCA locations. However, PHMSA emphasizes that this 4-year timeframe does not supersede, invalidate, or otherwise modify the existing requirements in § 192.611 for operators to confirm or revise the MAOP of

[65] See section 5.9.1 of the RIA for further details.

[66] Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; *https://www.govinfo.gov/content/FR-2012-05-07/pdf/2012-10866.pdf.*

segments within 24 months of a change in class location.

PHMSA also acknowledges that some commenters thought the 15-year compliance timeframe for MAOP reconfirmation was too long. PHMSA believes a 15-year timeframe is necessary to be consistent with § 192.939, which allows operators to use a confirmatory direct assessment to confirm their MAOP in two, 7-year inspection cycles. This timeframe was discussed by the GPAC and was approved by unanimous vote. PHMSA will note that operators are required to have 50 percent of the applicable mileage completed within 8 years of the effective date of the rule. PHMSA would expect operators to prioritize and reconfirm the MAOP of the highest-risk segments first.

PHMSA is also withdrawing miscellaneous revisions to § 192.503, which tied general requirements of the subpart J pressure test to alternative MAOP and MAOP reconfirmation provisions, and miscellaneous revisions from § 192.605(b)(5), which cross-referenced several sections related to MAOP requirements to the requirements regarding an operator's procedural manuals. These changes were made to simplify the regulations.

Additionally, because PHMSA has eliminated pipeline segments with past in-service incident history from the scope of the MAOP reconfirmation requirements, PHMSA is striking the proposed references within the MAOP reconfirmation requirements to the alternative MAOP requirements at § 192.620(a)(ii). Operators who used the alternative requirements to establish the MAOP of their pipelines were required to have complete documentation [67] and therefore would not be subject to the MAOP reconfirmation requirements. If an operator had previously established the MAOP of a pipeline segment under the alternative MAOP requirements, but has since lost the records necessary to validate the alternative, they would have to reconfirm MAOP using the alternative MAOP requirements, or apply for a special permit to continue operation.

Per the requirement in section 23 of the 2011 Pipeline Safety Act, PHMSA consulted with members of FERC and State regulators, including representatives from NAPSR and the National Association of Regulatory Utility Commissioners, as appropriate, to establish the timeframes for completing MAOP reconfirmation. As a part of this consultation, which occurred as a function of the GPAC meetings from 2017 through 2018, PHMSA accounted for potential consequences to public safety and the environment while also accounting for minimal costs and service disruptions. These representatives provided both input and positive votes that the provisions surrounding MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if certain changes were made. As previously discussed, PHMSA has taken the GPAC's input into consideration when drafting this final rule and made the according changes to the provisions.

B. MAOP Reconfirmation—§§ 192.624 & 192.632

ii.—Methods

In developing regulations to reconfirm MAOP where necessary, Congress mandated that PHMSA consider safety testing methodologies that include pressure testing and other alternative methods, including in-line inspections, determined to be of equal or greater effectiveness. The NTSB recommended an expansive pressure test approach to address the safety issues identified in their investigation of the PG&E incident through recommendations P–11–14 and P–11–15. In response to the congressional mandate, PHMSA evaluated other methodologies and identified five additional methods that could provide an equivalent or greater level of safety. Therefore, PHMSA proposed to allow the following six methods for MAOP reconfirmation, including the conventional pressure test method.

Summary of PHMSA's Proposal: Method 1—Pressure Test

A pressure test is the most conventional assessment method by which an operator may reconfirm a pipeline segment's MAOP. PHMSA proposed standards for conducting pressure tests for MAOP reconfirmation in part to meet the intent of NTSB recommendations P–11–14 and P–11–15. First, PHMSA proposed minimum test pressure standards where a pipeline segment's MAOP would be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor. Second, if the pipeline segment might be susceptible to cracks or crack-like defects,[68] then the operator must incorporate a spike pressure feature into the pressure test procedure. PHMSA proposed standards for the spike hydrostatic test in § 192.506. If the operator has reason to believe any pipeline segment may be susceptible to cracks or crack-like defects, the operator would be required to also estimate the remaining life of the pipeline in accordance with the same standards specified in Method 3, the engineering critical assessment method.

Summary of Public Comment: Method 1—Pressure Test

Several commenters opposed the proposed provisions requiring a spike test to be conducted as part of the pressure test for the purposes of MAOP reconfirmation, and these comments are discussed further under the ''spike test'' portion of the proposal and comment summary of this rulemaking.

API suggested that a pipeline segment's MAOP can be best established through performing a combination of pressure tests and ILI examinations, and they discussed how operators could conduct hydrostatic pressure testing to determine the in-place yield strength of a segment of pipeline by conducting a ''spike'' test pressure held for a few minutes followed by a subpart J pressure test approximately 10 percent below the spike level. API further stated that using ILI tools in conjunction with this method would further substantiate the results, as geometry ILI tools capable of measuring inside diameter to detect yielding could further substantiate and quantify the results of the pressure test.

AGA stated that while they believe that pressure testing is a straightforward and well-established method, the proposed Method 1 MAOP reconfirmation requirements are unnecessarily complex. AGA further stated that subpart J provides different requirements and specifications for pressure tests based on the type of pipe being tested, and that Method 1 should refer to subpart J rather than to § 192.505(c) specifically, which requires unnecessarily stringent requirements. PG&E supported the proposed provisions and committed to pressure testing all pipes.

INGAA stated that since the basic strength properties of steel pipe do not change over time, PHMSA should not limit allowable tests to only those conducted after July 1, 1965, as was proposed in § 192.619(a)(2)(ii). They emphasized that the test parameters, not

[67] ''Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines; Final Rule;'' October 17, 2008; 73 FR 62148. The effective date of the rule was November 17, 2008.

[68] These pipelines can include pipelines constructed with ''legacy pipe'' or using ''legacy construction techniques;'' pipelines with evidence or risk of stress corrosion cracking or girth weld cracks; or pipelines that have experienced an incident due to an original manufacturing-related defects, construction-related defects, installation-related defects, or fabrication-related defects.

the test date, should be considered for MAOP reconfirmation. Further, INGAA stated that recognizing the validity of earlier tests would not necessarily mean that no further pressure tests would be conducted, as periodic testing may be required to ensure the continued integrity of the pipeline segment under the operator's integrity management program. However, such additional tests are managed under IM, which is separate from MAOP reconfirmation.

Certain commenters stated that a spike test is not required to establish an adequate margin of safety for MAOP reconfirmation and suggested PHMSA eliminate spike testing from the pressure test method of MAOP reconfirmation.

Regarding the proposed definitions of ''legacy pipe'' and ''legacy construction,'' AGA and Xcel Energy commented that as proposed, the definitions could be interpreted to apply to distribution pipelines as well as gas transmission pipelines. Commenters requested that PHMSA explicitly exclude distribution pipelines from these definitions, which would be applicable to all part 192.

On March 26, 2018, the GPAC recommended that PHMSA delete the spike test requirements from the pressure test method of MAOP reconfirmation. The GPAC also recommended that PHMSA require operators to perform a pressure test in accordance with subpart J of part 192 rather than refer to specific requirements in § 192.505. Further, and as discussed during the meetings of December 2017 and March 26, 2018, if the applicable pressure test segment does not have traceable, verifiable, and complete MAOP records, the operator must use the best available information upon which the MAOP is currently based to conduct the pressure test. The GPAC recommended PHMSA create a requirement for the operator of such a pipeline segment to add the test segment to its plan for opportunistically verifying material properties in accordance with the material properties verification provisions. During the meeting, PHMSA noted that most pressure tests would present at least two opportunities for material properties verification at the test manifolds.

PHMSA Response: Method 1—Pressure Test

PHMSA appreciates the information provided by the commenters regarding the pressure test method of MAOP reconfirmation (Method 1). After considering these comments and as recommended by the GPAC, PHMSA is eliminating the spike testing requirement as part of the pressure test method of MAOP reconfirmation. As commenters stated, spike testing is primarily used for the mitigation of cracks and crack-like defects, and PHMSA has determined it would therefore be more appropriate to be placed within the context of threat management under IM. Additionally, PHMSA is removing the definitions for and related references to ''legacy pipe'' and ''legacy construction'' in this final rule because the applicability to pipe with ''legacy pipe or construction'' leaks or failures was dropped from the applicability criteria for MAOP reconfirmation. PHMSA also modified the rule to refer to subpart J pressure tests rather than paragraph § 192.505(c), specifically, and to recognize the validity of earlier pressure tests. Lastly, if an operator does not have traceable, verifiable, and complete records for the material properties needed to establish MAOP by pressure testing, PHMSA is requiring that operators test, in accordance with the material verification requirements, the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. Further, if there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with the material properties verification requirements to ensure that the segment of pipe is consistent with operator's sampling program established under § 192.607. This will avoid issues where operators may not have the documented and verified physical pipeline material properties and attributes that would otherwise be necessary to perform a hydrostatic pressure test to reconfirm MAOP.

Summary of Proposal: Method 2—Pressure Reduction

In the NPRM, PHMSA proposed that pipeline operators could choose to reduce the MAOP of the applicable pipeline segment to reconfirm the segment's MAOP. This approach would use the recent operating pressure as a *de facto* pressure test, and then an operator would set the pipeline segment's MAOP at a slightly lower pressure. PHMSA proposed that operators using this method set the pipeline's MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding the effective date of the final rule divided by the greater of either 1.25 or the applicable class location, which are the same safety factors as used for the pressure testing in Method 1. PHMSA included standards for establishing the highest actual sustained pressure for the purposes of reconfirming MAOP under this method and included standards for addressing class location changes. Additionally, PHMSA proposed that, if the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects, the operator would be required to estimate the remaining life of the pipeline.

Summary of Public Comment: Method 2—Pressure Reduction

AGA commented that the 18-month look-back time frame listed in the pressure reduction MAOP reconfirmation method is a much too narrow time frame for consideration and that the section should be rewritten to clarify that the pressure reduction should be taken from either (1) the immediate past 18 months, or (2) 5 years from the time the last pressure reduction was taken, stating that tying the baseline pressure to the effective date of the rule is arbitrary. Enterprise Products recommended that PHMSA clarify the derating criteria used for pipes that use this method of reconfirming MAOP. Further, Piedmont expressed concern that this method does not account for the actual gap that can occur between MAOP and operating pressure. Some commenters questioned whether the MAOP from which to take a pressure reduction was based on the most recent pressure test or the historical highest-pressure test, and some commenters suggested PHMSA revise this provision to allow operators to reconfirm the MAOP based on the existing MAOP and not using an 18-month look-back period unless an incident caused by a material-related or construction-related defect has occurred on the pipeline since its last subpart J pressure test.

TPA stated that using this method unfairly penalizes operators in situations where the operator has prepared for future needs and has not operated at MAOP for a period greater than 18 months. Similarly, another commenter suggested that operators who have already reduced MAOP on pipeline segments to be proactive should not be penalized by having to take an additional reduction in MAOP.

Some commenters recommended limiting the applicability of this method to those pipelines operating at 30 percent SMYS or greater.

Regarding the pressure reduction method for MAOP reconfirmation, the GPAC recommended PHMSA increase the look-back period from 18 months to 5 years and remove the requirements for operators selecting to take the pressure reduction to reconfirm MAOP to

perform fracture mechanics analysis on those pipeline segments.

PHMSA Response: Method 2—Pressure Reduction

PHMSA appreciates the information provided by the commenters regarding the pressure reduction method of MAOP reconfirmation (Method 2). After considering these comments and as recommended by the GPAC, PHMSA is increasing the look-back period to 5 years from the publication date of the rule and is removing the requirements for operators to perform fracture mechanics analysis on those pipeline segments where the operator has selected Method 2. PHMSA made this change because the 5-year look-back period is consistent with IM requirements regarding MAOP confirmation.

Summary of PHMSA's Proposal: Method 3—Engineering Critical Assessment

Method 3 directly addresses the congressional mandate for PHMSA to consider safety testing methodologies that include other alternative methods, including ILI, determined to be of equal or greater effectiveness. Demonstrating that knowledge gained from an ILI assessment provides an equivalent level of safety as a pressure test is technically challenging. PHMSA used best safety practices gained from implementation of integrity management since 2003; development of class location special permits; and technical research on related topics, such as analysis of crack defects and seam defects. PHMSA applied these principles and analytical methods to develop an engineering critical assessment (ECA) methodology, which applies state-of-the-art fracture mechanics analysis to analyze defects in the pipe and determine if those defects would or would not survive a hydrostatic pressure test at the test pressure needed to establish MAOP. In addition, PHMSA proposed that if the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects, the operator would be required to estimate the remaining life of the pipeline using the fracture mechanics standards PHMSA specified.

Summary of Public Comment: Method 3—Engineering Critical Assessment

Several trade associations and pipeline industry entities stated that ILI is the best and most practical method for MAOP reconfirmation due to its cost-effectiveness and environmentally friendly nature, and that PHMSA should allow operators to use ILI as a reconfirmation method. These commenters, however, also stated that the requirements proposed for the usage of ILI with an ECA are overly complicated and burdensome, and they specifically recommended that the final rule should be simplified so that this method will play a greater role in MAOP reconfirmation in lieu of a pressure test. For example, INGAA asserted that PHMSA should remove the requirements in the ECA related to operations, maintenance, and integrity management, arguing that these requirements do not factor into MAOP reconfirmation and would be covered elsewhere in part 192. Further, INGAA proposed additional alternatives for using the ECA method to obtain necessary data for MAOP reconfirmation, asserting that these alternatives would be less burdensome and equally effective. More specifically, INGAA suggested removing duplicate regulatory language, removing the pre-approval process for ILI, and adding unity plots as a method for operators to demonstrate that ILI is reliable for identifying and sizing actionable anomalies. TransCanada and PECO Energy Co. stated that for the ECA method to be used by industry, the detailed requirements listed under this method in the proposed rule should be replaced with the use of standard ECA best practices.

Some commenters suggested that operators have long relied on sound engineering judgments and conservative assumptions to account for record gaps. Commenters stated that, if stripped of the ability to use sound engineering judgment and conservative assumptions, operators would need to substantially invest in processes, procedures, tests, and project engineering and support to develop and implement a comprehensive material properties verification plan as outlined in the proposed regulations. Another commenter asked for clarification on using assumptions of Grade A pipe (30,000 psi) versus the use of 24,000 psi as noted in § 192.107(b)(2) if the SMYS or actual material yield strength and ultimate tensile strength is unknown or is not documented in traceable, verifiable, and complete records.

Another commenter suggested that in cases where a pipeline has been pressure tested, but not to the level of 1.25 times MAOP, PHMSA should allow operators to augment the original test with an ECA and other analysis to reconfirm the pipeline segment's MAOP under method 3.

The PST stated that there are certain cases in which the ECA method should not be allowed as an alternative to pressure testing. Citing a white paper prepared by Accufacts, Inc. on ECA methodology, the PST recommended that PHMSA prohibit the use of the ECA method for determining the strength of a pipeline segment in cases where there are girth weld crack threats, significant stress corrosion cracking threats, or dents with stress concentrator threats.

During the GPAC meeting on March 27, 2018, the GPAC recommended that PHMSA remove the fracture mechanics analysis for failure stress and crack growth analysis requirements from the ECA method of MAOP reconfirmation and move them to a stand-alone section in the regulations. Further, the GPAC recommended that such a section should not specify when, or for which pipeline segments, fracture mechanics analysis would be required. The GPAC suggested that this new fracture mechanics section outline a procedure by which operators perform fracture mechanics analysis when required or allowed by other sections of part 192, which was similar to its treatment of the proposed material properties verification procedures at § 192.607. Under the GPAC's proposal, the ECA method for MAOP reconfirmation would not contain any specific technical fracture mechanics requirements or Charpy V-notch toughness values but would instead refer to the new fracture mechanics section. Other recommendations related specifically to the new fracture mechanics section are discussed in that area of the proposal and comment summary section of this document.

The GPAC also recommended PHMSA add a requirement to verify material properties in accordance with the rule's material properties verification provisions if the information needed to conduct a successful ECA is not documented in traceable, verifiable, and complete records.

PHMSA Response: Method 3—Engineering Critical Assessment

PHMSA appreciates the information provided by the commenters regarding the ECA method of MAOP reconfirmation (Method 3). As recommended by the GPAC, PHMSA is removing the fracture mechanics analysis requirements from the ECA method of MAOP reconfirmation and moving them to a new stand-alone § 192.712. PHMSA agrees this change will improve comprehension of the regulations. This new section does not specify when, or for which pipeline segments, fracture mechanics analysis would be required but instead outlines a procedure by which operators perform

fracture mechanics analysis when required by other sections of part 192. Section 192.712 is referenced in the pressure reduction, ECA, and ''other technology'' methods of MAOP reconfirmation under § 192.624, as well as in § 192.917 for cyclic fatigue loading. Therefore, the ECA method for MAOP reconfirmation does not contain any specific technical fracture mechanics requirements or Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) but instead refers to the new § 192.712. Comments related to the assumptions an operator can use when material properties are unknown are addressed in the discussion on § 192.712 below. PHMSA also added a requirement to verify material properties in accordance with the rule's material properties verification provisions at § 192.607 if the information needed to conduct a successful ECA is not documented in traceable, verifiable, and complete records.

PHMSA disagrees that the additional analytical requirements, beyond ILI, are overly complicated or burdensome. To conclude that an ECA is of equal or greater effectiveness as a pressure test for the purposes of MAOP reconfirmation, as mandated by Congress, more than an ILI and repair program is required. A pressure test proves that any flaws in the pipe are small enough to hold the test pressure without leaking. Such subcritical flaws must be analyzed to prove that they would pass a pressure test, even if the pressure test is not conducted. A fracture mechanics analysis is capable of reliably drawing such conclusions but must be carefully and capably performed. Such an analysis also requires accurate data. In the absence of reliable data for key parameters, such as fracture toughness, PHMSA allows the use of appropriately conservative assumptions. This is discussed in more detail in the sections below.

Based on an ASME report and research sponsored by PHMSA,[69] the ECA analysis can be reliably used to ascertain if a pipeline segment would pass a pressure test, even if it has seam weld cracking, and the final rule includes requirements for conducting ILI using tools capable of detecting girth weld cracks. The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of each defect.

PHMSA also notes that the final rule addresses cases where a pipeline has been pressure tested, but not to the level of 1.25 times MAOP, by allowing operators to account for those test results and augment the original test with an ECA, or conduct an ILI tool assessment program to characterize defects remaining in the pipe along with using an ECA to establish MAOP, to reconfirm the pipeline segment's MAOP using Method 3. Detailed ILI requirements are addressed in new § 192.493, which is discussed in more detail below.

PHMSA is moving the ECA process requirements in this final rule to a new stand-alone § 192.632. Section 192.624(c)(3) (ECA method of MAOP reconfirmation) and the new § 192.632 will cross-reference each other. PHMSA decided to make this change when finalizing this rulemaking only to improve the readability of the regulations. No substantive changes were made to the requirements in connection with this organizational change.

Summary of PHMSA's Proposal: Method 4—Pipe Replacement

When reconfirming MAOP on certain pipeline segments, some operators may face significant technical challenges or costs when performing either a pressure test or an ILI examination, and it may be more economically viable to replace the pipeline. Therefore, PHMSA proposed to allow pipe replacement for operators to reconfirm their MAOP. In such cases, the replacement pipeline would be designed, constructed, and pressure tested according to current standards to establish MAOP.

Summary of Public Comment: Method 4—Pipe Replacement

Commenters, including Mid-American Energy Company and Paiute Pipeline, stated their support for this method. The GPAC similarly supported this method and did not recommend any changes for this aspect of MAOP reconfirmation.

PHMSA Response: Method 4—Pipe Replacement

PHMSA appreciates the information provided by the commenters regarding the pipe replacement method of MAOP reconfirmation (Method 4). After considering these comments and as recommended by the GPAC, PHMSA is retaining the proposed rule text for Method 4 in the final rule.

Summary of PHMSA's Proposal: Method 5—Pressure Reduction for Small, Low-Pressure Pipelines

For low-pressure, smaller-diameter pipeline segments with small potential impact radii (PIR), PHMSA proposed an MAOP reconfirmation method similar to the pressure reduction under Method 2. Operators of pipeline segments for which (1) the MAOP is less than 30 percent SMYS, (2) the PIR is less than or equal to 150 feet, (3) the nominal diameter is equal to or less than 8 inches,[70] and (4) which cannot be assessed using ILI or a pressure test, may reconfirm the MAOP as the highest actual operating pressure sustained by the pipeline segment 18 months preceding the effective date of the final rule, divided by 1.1. In addition to this pressure reduction, operators of these lines would be required to perform external corrosion direct assessments in accordance with the IM provisions, develop and implement procedures to evaluate and mitigate any cracking defects, conduct a specified number of line patrols at certain intervals, conduct periodic leak surveys, and odorize the gas transported in the pipeline segment.

Summary of Public Comment: Method 5—Pressure Reduction for Small, Low-Pressure Pipelines

AGA stated that PHMSA did not provide enough justification for imposing the additional pressure reduction requirements listed under this method, asserting that this method should require either a 10 percent pressure reduction or the implementation of additional preventative actions that are feasible and practical, but not both. TPA stated that the 18-month criterion penalizes operators who may have operated pipelines at lower capacities to anticipate future needs. Furthermore, TPA urged PHMSA to limit the requirements for MAOP reconfirmation under Method 5 to the reduction in MAOP and not impose additional safety requirements, stating that these pipelines are generally considered low-stress pipelines and that their risk of rupture is very low. Similarly, API stated that the proposed requirements for odorization and frequent instrumented leak surveys are impractical. Some commenters felt that the terms for small potential impact radius and the applicable diameters should be defined.

[69] See: American Society of Mechanical Engineers (ASME) Standards Technology Report ''Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (STP–PT–011), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5); *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.*

[70] 8.625 inches actual diameter.

On March 27, 2018, the GPAC recommended PHMSA delete the size and pressure criteria of this method and base the applicability solely on a potential impact radius of less than or equal to 150 feet. The GPAC also recommended increasing the look-back period to 5 years from 18 months. Further, the GPAC recommended PHMSA strike the additional requirements in this method related to external corrosion direct assessment, crack analysis, gas odorization, and fracture mechanics analysis. They also recommended PHMSA change the frequency of patrols and surveys to 4 times a year for Class 1 and Class 2 locations, and 6 times per year for Class 3 and Class 4 locations.

PHMSA Response: Method 5—Pressure Reduction for Small, Low-Pressure Pipelines

PHMSA appreciates the information provided by the commenters regarding the pressure reduction method of MAOP reconfirmation for small, low-pressure pipelines (Method 5). After considering these comments and as recommended by the GPAC, PHMSA is deleting the pipeline segment size and pressure criteria of this method and basing the applicability solely on a potential impact radius of less than or equal to 150 feet. PHMSA believes this change streamlines the regulations while maintaining pipeline safety. PHMSA is increasing the look-back period to 5 years, which is consistent with other sections of part 192, including integrity management. Additionally, PHMSA is deleting the requirements in this method related to external corrosion direct assessment, crack analysis, gas odorization, and fracture mechanics analysis. PHMSA is also changing the frequency of patrols and surveys to 4 times a year for Class 1 and Class 2 locations, and 6 times per year for Class 3 and Class 4 locations. PHMSA believes these changes increase regulatory flexibility while maintaining pipeline safety.

Summary of Proposal: Method 6—Alternative Technology

PHMSA proposed that operators may use an alternative technical evaluation process that provides a documented engineering analysis for the purposes of MAOP reconfirmation. If an operator elects to use an alternative method for MAOP reconfirmation, it would have to notify PHMSA and provide a detailed fracture mechanics analysis—including the safety factors—to justify the establishment of the MAOP using the proposed alternative method. The notification would have to demonstrate that the proposed alternative method would provide an equivalent or greater level of safety than a pressure test. PHMSA included this option to allow and encourage the continual research and development needed to improve state-of-the-art fracture mechanics analysis, integrity assessment methods, advances in metallurgical engineering, and new techniques.

Summary of Public Comment: Method 6—Alternative Technology

For the alternative technologies method of MAOP reconfirmation, several stakeholders opposed the timeframes, case-by-case approval process, and procedural barriers PHMSA proposed for using this method. Several commenters, including Cheniere Energy, Delmarva Power & Light, and INGAA, suggested that the procedural hurdles required by the proposed provisions would make this option difficult for operators to use for MAOP reconfirmation as well as for any other provisions PHMSA allows alternative technology use with notification. More specifically, these commenters suggested that a process whereby PHMSA could object to the use of an alternative technology at any time during a project's lifecycle does not provide the level of certainty necessary for operators to move forward with using alternative technologies. That uncertainty would deter the development of what could be better or safer alternatives.

Piedmont stated that it does not believe that the role of PHMSA includes determining the appropriate technologies to be used to reconfirm MAOP. Piedmont further stated that currently under subpart O, operators are required to obtain approval from PHMSA to use alternative technologies for integrity assessment, and that operators have waited more than 180 days for PHMSA to respond to these requests. Piedmont stated that this uncertainty cannot be reconciled with the planning and business considerations that an operator must consider when evaluating how to invest in technology and which methods to use for establishing MAOP. The PST stated that the approval process should be similar to the process used for special permits and that before these methods are approved by PHMSA, they should be subject to public review and comment under the National Environmental Policy Act of 1969 (NEPA).

At the meeting on March 27, 2018, the GPAC recommended PHMSA incorporate the 90-day notification and objection procedure for the use of alternative technology. To summarize, operators would have to notify PHMSA of its intent to use other technology, and PHMSA would have 90 days to respond with an objection if PHMSA had one, or a need for more review time. Otherwise, the operator would be free to use the proposed method or technology.

PHMSA Response: Method 6—Alternative Technology

PHMSA appreciates the information provided by the commenters regarding the other technology method of MAOP reconfirmation (Method 6). After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to incorporate the 90-day notification and objection procedure the committee recommended. Operators would have to notify PHMSA of its intent to use other technology to reconfirm MAOP in accordance with § 192.18, and PHMSA would have 90 days to respond with an objection if PHMSA had one or a notice that PHMSA required more time for its review, which would extend the timeframe. Without a notice of objection or additional review by PHMSA, the operator would be allowed to use the alternative technology. PHMSA has successfully applied the notification process to other technology assessments under subpart O since its inception and does not believe a special permit process is warranted for every notification for alternative technology. PHMSA believes the changes made in the final rule will address the concerns about timeliness of notification reviews by PHMSA.

B. MAOP Reconfirmation—§ 192.624 iii.—Spike Test

1. Summary of PHMSA's Proposal

The ''spike'' hydrostatic pressure test is a special feature of the pressure testing method of MAOP reconfirmation. PHMSA intends this aspect of the MAOP reconfirmation process to address the intent of NTSB recommendations P–11–14 (related to spike testing for grandfathered pipe) and P–11–15 (related to pressure testing to show that manufacturing and construction-related defects are stable).

PHMSA proposed that a spike test would be required for cases where a pipeline segment might be susceptible to cracks or crack-like defects. Such pipe may include ''legacy pipe;'' pipe constructed using ''legacy'' construction techniques; pipelines that have experienced an incident due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect; or pipe with

stress corrosion cracking or girth weld cracks. Cracks and crack-like defects in some cases may be susceptible to a phenomenon called ''pressure reversal,'' which is the failure of a defect at a pressure less than a pressure level that the flaw has previously experienced and survived. The increased stress from the test pressure may cause latent cracks that are almost, but not quite, large enough to fail to grow during the test. If the crack does not fail before the test is completed, the resultant crack that remains in the pipe may be large enough to no longer be able to pass another pressure test. The spike portion of the pressure test is designed to cause such marginal crack defects to fail during the early, spike phase of the pressure test. The post-spike, long-duration test pressure validates the operational strength of the pipe. Using a short-duration, very high spike pressure followed by a long-duration integrity verification pressure provides greater assurance that the test is not ''growing cracks'' that could fail in-service after the test is completed. PHMSA proposed standards for the spike hydrostatic test in § 192.506. PHMSA used several technical reports and studies, including PHMSA-sponsored research, to inform the standards proposed for the spike test. Those materials include, American Society of Mechanical Engineers Standards Technology Report ''Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (STP–PT–011), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5).[71]

2. Summary of Public Comment

Some commenters supported the concept of requiring the use of a spike hydrostatic pressure test as part of the MAOP reconfirmation process for establishing MAOP but expressed concern over specific aspects of the provision. For example, AGA urged PHMSA to allow pneumatic pressure tests as well as hydrostatic pressure tests. In addition, AGA disagreed with the allotted test duration provided in the proposal. Similarly, other operators who commented, such as CenterPoint Energy and Dominion East Ohio, stated that the proposed spike test target hold pressure of 30 minutes exceeds the time needed to determine the mechanical integrity of the pipeline test segment and will cause pre-existing crack-like defects to grow. Alternatively, Dominion Transmission, Tallgrass Energy Partners, SoCalGas, and Paiute Pipelines stated that a test level of 100 percent SMYS, not 105 percent SMYS, would be sufficient to remediate cracking threats. Enterprise Products stated that the requirements for the design of a spike test should be based on integrity science, such as fatigue life and reassessment intervals, and suggested PHMSA's proposed spike test pressure limits were set at an arbitrary level. Enterprise further stated that the utility of stressing a pipe beyond 100 percent of its yield strength is questionable and potentially damages the pipe. Other commenters, including MidAmerican Energy Co., requested that pneumatic spike tests to 1.5 times MAOP be allowed when the resultant pressure complies with the limitations stated in the table in § 192.503(c).

Trade associations and pipeline industry entities, including INGAA, GPA, and TPA, asserted that PHMSA should eliminate the spike test requirement for establishing MAOP entirely. These commenters stated that the proposed provisions went beyond what was required to reconfirm MAOP for an accepted margin of safety. These commenters further asserted that spike testing is not an appropriate technique for MAOP reconfirmation, and it could result in unintended negative consequences without improving pipeline safety. They stated that spike testing is an aggressive and destructive technique that should be used only in cases in which time-dependent threats, such as a significant risk of stress corrosion cracking, exist.

INGAA and other commenters agreed with PHMSA that the use of spike hydrostatic testing is appropriate for time-dependent threats, such as stress corrosion cracking. INGAA, however, suggested changes to the proposed spike hydrostatic pressure test provisions and the cross-reference to those provisions in the proposed IM assessment method revisions to limit the spike testing requirement to time-dependent threats, to test to a minimum of 100 percent SMYS instead of 105 percent, and to provide an alternative for use of an instrumented leak survey. INGAA agreed that spike testing is the best means of testing a pipeline with a history of environmental cracking, such as stress corrosion cracking that has developed while a pipeline is in service, and noted that a spike test may be of value for in-service pipelines where metallurgical fatigue is of concern. INGAA further stated that pressure cycling should not need to be included in the proposed spike test provisions and that PHMSA should amend the proposed rule to limit spike testing only to those pipeline segments with stress corrosion cracking.

An additional commenter suggested PHMSA should allow operators to use the short-duration spike portion of a spike pressure test to determine the lower bound of the yield strength of the test section, including all pipe and components that are subjected to the test pressure. Such a test, if used for this purpose, must also confirm that yielding beyond that experienced in a standard tensile test to determine yield strength, typically on the order of 0.5 percent, has not occurred. This confirmation may be demonstrated by data from a pressure-volume plot of the test or a post-test geometry tool in-line inspection.

Public interest and other groups, including Pipeline Safety Coalition, Environmental Defense Fund (EDF), and NAPSR, expressed support for spike testing, stating that it would provide for increased pipeline safety. NAPSR further stated that the option of applying to use alternative technology or an alternative technological evaluation process would allow for some flexibility in cases in which a hydrostatic test is impractical. EDF also suggested additional measures to mitigate emissions from methane gas lost during testing.

At the GPAC meeting on March 2, 2018, the GPAC recommended that PHMSA revise the spike test requirements to change the minimum spike pressure to the lesser of 100 percent SMYS or 1.5 times MAOP, reduce the spike hold time to a minimum of 15 minutes after the spike pressure stabilizes, revise the applicable language to refer specifically to ''time-dependent'' cracking, incorporate the 90-day notification and objection procedure discussed for other sections, and adjust the SME requirements by adding language describing a ''qualified technical subject matter expert'' where applicable.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the requirements for spike pressure testing. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to change the minimum spike pressure to the lesser of 100 percent SMYS or 1.5 times MAOP, as PHMSA believes these pressures are sufficient to maintain pipeline safety. PHMSA is specifying a spike hold time of a minimum of 15 minutes after the spike pressure stabilizes, rather than a 30-minute overall hold time, to be consistent with pipeline safety. Additionally, PHMSA is

[71] *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.*

modifying the rule to revise the applicable language to refer specifically to ''time-dependent'' cracking, incorporate the same notification procedure under § 192.18 with the 90-day timeframe for objections or requests for more review time, and adjust the SME requirements by using broader language describing a ''qualified technical subject matter expert'' where applicable instead of specifying technical fields of expertise such as metallurgy or fracture mechanics. PHMSA believes these changes increase regulatory flexibility while maintaining pipeline safety.

In addition, as stated above, the spike test is being removed from the MAOP reconfirmation requirements. The spike test procedure in the new § 192.506 would be used whenever required by other requirements in part 192 to address crack remediation and the integrity threat of cracks and crack-like defects.

PHMSA disagrees with allowing pneumatic spike tests to 1.5 times MAOP based on safety concerns. Pneumatic pressure tests are allowed in § 192.503(c), with certain limitations, for new, relocated, or replaced pipe. For new, relocated, or replaced pipe, there is knowledge that the pipe is likely sound and is usually manufactured with recent mill pressure tests to confirm the pipe meets applicable standards. A spike test to perform an integrity assessment on *in-situ* pipe with known or suspected cracks or crack-like defects presents a much higher likelihood of the pipeline segment experiencing a leak or rupture during the test with resultant consequences, including the possibility of fire or explosion. PHMSA notes that conducting a pneumatic test using a compressible gas, such as air, nitrogen, or methane, would be a safety concern for the public and operating personnel. Gas that is highly compressed has stored energy that would be suddenly released should there be a flaw in the pipe. Liquids, such as water, do not have the stored energy release that a compressible gas has should the pipe have a flaw that either leaks or ruptures. Therefore, the safety risk of performing a hydrostatic pressure test (with water) is much lower due to the less-compressible nature of liquids. Compressed gas would be a fire or explosion hazard to the public. However, as specified in the proposed and final rules, operators that desire to use a pneumatic spike test may propose using such a test, with justification, by submitting a notification to PHMSA.

B. MAOP Reconfirmation—§ 192.624

iv.—Fracture Mechanics

1. Summary of PHMSA's Proposal

In the proposal, PHMSA determined that fracture mechanics analysis is a key aspect of meeting the congressional mandate to consider safety testing methodologies for MAOP reconfirmation of equal or greater effectiveness as a pressure test, including other alternative methods such as ILI. Demonstrating that knowledge gained from an ILI assessment provides an equivalent level of safety as a pressure test is technically challenging. An ILI assessment might reveal the presence of crack flaws and crack-like defects and characterize them within the accuracy of tool performance capabilities, but determining whether those cracks would survive a pressure test to reconfirm MAOP requires very in-depth and highly technical analysis. Such an analysis not only requires an accurate characterization of cracks, it also requires accurate and known metallurgical properties of the pipe. To address these aspects, PHMSA proposed more detailed requirements in § 192.921 for evaluating defects discovered during ILI to account for tool accuracy and other factors to accurately characterize flaw dimensions and support accurate fracture mechanics analysis. In addition, the material properties verification and documentation requirements PHMSA proposed are critical to performing fracture mechanics analysis of ILI-discovered defects that would be accurate enough to establish MAOP in a way that is demonstrably equivalent in safety to a pressure test. In the MAOP reconfirmation provisions, PHMSA proposed new requirements for fracture mechanics analysis for failure stress and cracks, listing specific requirements, standards, and data operators must use when performing a fracture mechanics analysis.

2. Summary of Public Comment

Most industry stakeholders were opposed to the proposed fracture mechanics requirements. AGA, New Mexico Gas Co., and TPA suggested that fracture mechanics have a limited place in preventing pipeline failures or predicting them accurately and should not be a component of MAOP reconfirmation. AGA stated that the rule should not prescriptively require fracture mechanics calculations to be performed for a broad range of applications but should be narrowed to include only transmission pipelines operating at a hoop stress greater than 30 percent SMYS, given that pipelines that operate below 30 percent SMYS have a strong tendency to leak rather than rupture.

Commenters also stated that requiring fracture mechanics as any part of the MAOP reconfirmation process was overly burdensome and unclear. Specifically, API stated that some of the requirements listed under the MAOP reconfirmation requirements were overly conservative and burdensome for most situations where this technique would be used. For instance, a commenter noted that there is no non-destructive evaluation (NDE) methodology for obtaining Charpy V-notch toughness values. Therefore, PHMSA's requirement to obtain Charpy V-notch toughness values eliminates the availability of non-destructive testing. Further, a commenter noted that the proposed ECA analysis prescribed a body toughness of 5-ft.-lbs. and a seam toughness of 1-ft.-lbs., which are arbitrary and very conservative. Vintage pipelines will not have Charpy V-notch toughness data, and requiring an overly conservative assumption of toughness is not reasonable. Toughness can vary depending on the manufacturer, the manufacturing method, and the pipe vintage, and it should not be prescribed in the regulations. The commenter further noted that using the conservative defaults, especially the overly conservative defaults PHMSA proposed, may result in an unacceptably short remaining life of the pipeline.

Similarly, commenters recommended PHMSA allow alternative methods of assessing strength properties that provide a suitable lower bound to the actual strengths. Allowing alternative methods will provide flexibility to consider conservative, but realistic, estimates of material properties. Commenters also stated that SMEs in both metallurgy and fracture mechanics are not needed to validate non-destructive test (NDT) methods. Engineers with knowledge in test validation methods but not necessarily metallurgy and fracture mechanics are capable of validating NDT methods.

More broadly, Energy Transfer Partners suggested that the proposed language for fracture mechanics is misplaced in MAOP reconfirmation and should be moved to the proposed requirements for non-HCA assessments, or elsewhere, since this text more closely resembles an ''assessment.'' Other commenters agreed with that concept, suggesting fracture mechanics is more appropriate under the IM measures for threat mitigation rather than for MAOP reconfirmation.

As previously discussed in this document, the GPAC recommended

PHMSA move the fracture mechanics analysis requirements out of the ECA method of MAOP reconfirmation and into a new stand-alone section in the regulations, making it a process for performing fracture mechanics analysis whenever required or allowed by part 192. The committee therefore recommended that PHMSA delete any cross-references to the MAOP reconfirmation and the spike pressure test provisions. The GPAC also recommended that operators make and retain specific records to document fracture mechanics analyses performed.

Along with moving the fracture mechanics analysis requirements to a stand-alone section, the GPAC had several specific recommendations related to how the requirements would function. The GPAC recommended PHMSA remove ILI tool performance specifications and replace them with a requirement for operators to verify tool performance using unity plots or equivalent technologies, and also recommended revisions to the fracture mechanics requirements by striking the sensitivity analysis requirements and replacing them with a requirement for operators to account for model inaccuracies and tolerances.

As it pertains to the Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) used in fracture mechanics analysis, the GPAC recommended that operators could use a conservative Charpy V-notch toughness value based on the sampling requirements of the material properties verification provisions or use Charpy V-notch toughness values from similar-vintage pipe until the actual properties are obtained through the operator's opportunistic testing program. The GPAC recommended that PHMSA clarify that default Charpy V-notch toughness values of 13-ft.-lbs. for pipe body and 4-ft.-lbs. for pipe seam only apply to pipe with suspected low-toughness properties or unknown toughness properties. Further, if a pipeline segment has a history of leaks or failures due to cracks, the GPAC recommended PHMSA require the operator to work diligently to obtain any unknown toughness data. In the interim, operators of such pipeline segments must use Charpy V-notch toughness values of 5-ft.-lbs. for pipe body and 1-ft.-lbs. for pipe seam. The GPAC also recommended PHMSA include a 90-day notification procedure similar to the previously agreed-upon procedure if operators wanted to request the use of differing Charpy V-notch toughness values.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed fracture mechanics requirements. After considering these comments and as recommended by the GPAC, PHMSA is moving the fracture mechanics analysis requirements out of the ECA method of MAOP reconfirmation and into a new stand-alone § 192.712 in the regulations, making it a process by which operators must perform fracture mechanics analysis whenever required by part 192. This change was made to increase the readability of the regulations. As a part of making these provisions into a stand-alone section in the regulations, PHMSA is also deleting the references within § 192.712 to the MAOP reconfirmation and the spike pressure test provisions. PHMSA is adding a requirement for operators to make and retain specific records documenting any fracture mechanics analyses performed. PHMSA is also removing ILI tool performance specifications and sensitivity analysis requirements and replacing them with a requirement for operators to verify tool performance using unity plots or equivalent technologies and to account for model inaccuracies and tolerances. This change will increase regulatory flexibility while maintaining pipeline safety.

Regarding the default Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) used in fracture mechanics analysis when actual values are not known, industry and the GPAC had significant comments. PHMSA is aware of pipe manufactured per API Specification 5L in this decade (2010–2019) with Charpy V-notch toughness values for the weld seam as low as 1-ft. lbs. that has been used in gas transmission pipelines. Furthermore, API 5L does not contain required minimum Charpy V-notch toughness values for the weld seam.

A single default assumed toughness value might be inappropriate or overly conservative under some circumstances, or it might be a proper choice under other circumstances. To address this issue in this final rule, PHMSA is allowing the use of: (1) Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) from the same vintage and the same steel pipe manufacturers with known properties; (2) a conservative Charpy V-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607; (3) maximum Charpy V-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects if the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects; (4) maximum Charpy V-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion if the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects; or (5) other appropriate Charpy V-notch toughness values that an operator demonstrates can provide conservative Charpy V-notch toughness values for the analysis of the crack-related conditions of the line pipe upon submittal of a notification to PHMSA. These modifications will provide flexibility to operators for considering conservative but realistic estimates of material properties.

PHMSA is also clarifying that operators do not need to use distinct metallurgy and fracture mechanics subject matter experts to review fracture mechanics analyses. In this final rule, PHMSA is replacing that requirement with a general requirement stating that fracture mechanics analyses must be reviewed and confirmed by a qualified subject matter expert. PHMSA expects a qualified subject matter expert to be an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. The operator must be able to document that the individual is appropriately knowledgeable and experienced in the subject being assessed.

B. MAOP Reconfirmation—§ 192.624 v.—Legacy Construction Techniques/ Legacy Pipe

1. Summary of PHMSA's Proposal

PHMSA proposed to add a definition to part 192 for ''legacy construction techniques,'' which defined historical practices used to construct or repair transmission pipeline segments that are no longer recognized as acceptable. In addition, PHMSA proposed a definition for ''legacy pipe'' that is defined by the presence of specific legacy manufacturing, welding, and joining techniques.

2. Summary of Public Comment

AGA expressed significant concerns with the proposed definitions of legacy pipe and legacy construction techniques for the purposes of part 192, commenting that PHMSA should eliminate the use of the terms entirely or otherwise revise these definitions to

exclude currently acceptable manufacturing and construction techniques. AGA stated if PHMSA were to codify the definitions of legacy pipe and legacy construction techniques, then PHMSA should limit its catch-all provisions within the language of the definitions to pipes with a longitudinal joint factor of less than 1.0. Doing so would ultimately include pipes with unknown joint factors, as § 192.113 requires a default longitudinal joint factor of 0.80 for any pipe with an unknown longitudinal joint factor. Similarly, AGL Resources, Alliant Energy, Atmos Energy, and TECO Peoples Gas supported AGA's suggested revisions to the definitions of legacy construction techniques and legacy pipe. API commented that PHMSA's proposed definition of legacy construction technique inappropriately includes the repair technique of puddle welds and recommended PHMSA clarify the definitions of wrought iron and pipe made from Bessemer steel. Dominion Transmission commented there may be instances where the longitudinal seam for modern day pipe is unknown, yet the pipe is not a high-risk seam type. They stated that such pipe does not present an integrity threat and should be excluded from the ''legacy pipe'' definition.

Gas Piping Technology Committee commented that the proposed definition of legacy construction techniques seems to contain some erroneous information. They asserted that the proposed definition went too far by implying that all the listed methods are no longer used to construct or repair pipelines, stating that while wrinkle bends may no longer be a common construction technique, they are still allowed under § 192.315 for steel pipe operating at a pressure producing a hoop stress of less than 30 percent of SMYS. Similarly, Oleksa and Associates commented that some operators are still installing Dresser couplings.

The Michigan Public Service Commission staff suggested that PHMSA add to the definition of ''legacy construction techniques'' a subsection that addresses other legacy construction techniques that are not in the current list and include within this subsection language referencing ''all other'' techniques. Northern Natural Gas proposed PHMSA eliminate the phrase ''including any of the following techniques'' from the definition of legacy construction techniques as it implies the list is not complete. They suggested that the definition of legacy pipe should differentiate between ductile and brittle pipe by toughness values in both the seam and the pipe body. Lastly, SoCalGas thought it would be more appropriate to reference these definitions under the IM regulations in subpart O instead of defining the terms in the context of the entire part.

These definitions were taken up by the GPAC in the context of the scope of MAOP reconfirmation, and they recommended in the meeting on March 26, 2018, that the definitions be withdrawn. Because the GPAC recommended to revise the scope of MAOP confirmation to not include pipelines with previous reportable incidents due to crack defects, these definitions would no longer be needed in the rule.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed definitions for ''legacy pipe'' and ''legacy construction techniques.'' After considering these comments and as recommended by the GPAC, PHMSA is withdrawing these definitions from the final rule. Because the revised scope of MAOP confirmation requirements, discussed in the previous sections, no longer includes pipelines with previous reportable incidents due to crack defects, these definitions are no longer necessary.

C. Seismicity and Other Integrity Management Clarifications—§ 192.917

1. Summary of PHMSA's Proposal

Subpart O of 49 CFR part 192 prescribes requirements for managing pipeline integrity in HCAs. It requires operators of covered segments to identify potential threats to pipeline integrity and use that threat identification in their integrity programs. Included within this process are requirements to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment. Special requirements are included to address particular threats such as third-party damage and manufacturing and construction defects.

Following the PG&E incident, the NTSB recommended that PG&E evaluate every aspect of its IM program, paying particular attention to the areas identified in the incident investigation, and implement a revised IM program. PHMSA held a workshop on July 21, 2011, to address perceived shortcomings in the implementation of IM risk assessment processes and the information and data analysis (including records) upon which such risk assessments are based. PHMSA also sought input from stakeholders on these issues in the ANPRM.

Section 29 of the 2011 Pipeline Safety Act requires that operators consider the seismicity of the geographic area in identifying and evaluating all potential threats to each pipeline segment, pursuant to 49 CFR part 192. Pipeline threat analysis is addressed as one program element in the IM regulations in subpart O. Addressing seismicity is already implicitly required by § 192.917 as part of addressing outside force threat through the incorporation by reference of ASME B31.8S. Based on the direction of the mandate, PHMSA proposed to explicitly require that operators analyze seismicity and related geotechnical hazards, such as geology and soil stability, as part of the threat identification IM program element and mitigate those threats of outside force damage. PHMSA determined this would clarify expectations for this requirement and explicitly implement section 29 of the 2011 Pipeline Safety Act.

PHMSA also proposed revisions to § 192.917(e) to clarify that certain pipe designs must be pressure tested to assume that seam flaws are stable and that failures or changes to operating pressures that could affect seam stability are evaluated using fracture mechanics analysis.

2. Summary of Public Comment

There was broad support for explicitly requiring the consideration of the seismicity of a geographic area when identifying and evaluating all potential threats to a pipeline segment, and several stakeholders suggested minor revisions to the proposal. California Public Utilities Commission (CPUC) supported the proposed provisions and recommended adding text that would require consideration of any significant localized threat that could affect the integrity of the pipeline. CPUC further commented that operating conditions on the pipeline must also be a factor when operators identify local threats.

Some commenters, including PG&E and NGA, requested further clarification regarding what would constitute a seismic event for the purposes of identifying threats under the IM program for compliance purposes. AGA requested clarification on the requirements regarding whether operators are expected to conduct a one-time investigation on the risk of seismicity and geology, or if there is an expectation of a periodic requirement for re-investigation.

Multiple commenters disagreed with the proposed requirement in § 192.917(e) for operators to perform annual cyclic fatigue analyses if an operator identifies cyclic fatigue as a threat. INGAA and National Fuel

suggested that cyclic fatigue is an uncommon risk for natural gas pipelines and asserted that PHMSA did not provided significant technical justification for this analysis requirement. Some commenters suggested that the proposal to address cyclic fatigue and require pressure tests on seam threats is an overcompensation for the level of risk the threats present. Trade associations and pipeline industries proposed several alternative requirements for the conditions under which cyclic fatigue analyses should be required. API stated that they did not object to the measures listed, but the proposed provisions in § 192.935(b)(2) imply that an operator must take all the actions listed. API asserted that PHMSA should modify this proposed provision to state that operators must consider taking the actions listed but would not be specifically required to take all of them. Other commenters expressed concern that these proposed requirements conflict with the proposed requirements for pipeline segments needing to undertake MAOP reconfirmation because they experienced an incident due to manufacturing and construction (M&C) defects. Specifically, the requirements under § 192.917(e)(3) only allow operators to consider M&C defects stable if they have been subjected to a hydrostatic pressure test of 1.25 times MAOP, which would seemingly disallow or otherwise make fruitless the other methods of MAOP reconfirmation for these types of pipeline segments.

At the GPAC meeting on January 12, 2017, the GPAC recommended that no changes should be made to the proposed provisions on seismicity.

Regarding § 192.917(e)(2), which was discussed during the meeting on June 6–7, 2017, the GPAC noted that, under this provision, operators should be monitoring for condition changes that would cause the threat to potentially activate, and those condition changes should be what triggers a reassessment. The GPAC also noted problems with a suggested revision of performing a cyclic fatigue analysis within a 7-calendar-year period to match certain IM requirements because it would then impose a hard deadline on the continuous monitoring process and would prompt operators to act and again study cyclic fatigue even if the monitoring showed no evidence of cyclic fatigue being a threat. At the meeting, PHMSA suggested that operators could ensure the data involved in a cyclic fatigue analysis is periodically verified within a period not exceeding 7 years to align with IM requirements, but operators would only be required to perform a full evaluation if the data has changed. Following that discussion, the GPAC recommended revising the proposed requirements for cyclic fatigue at § 192.917 based on the discussion of GPAC members and considering PHMSA's proposed language that was presented at the meeting.

At the GPAC meeting on March 26–28, 2018, a public commenter suggested PHMSA remove the word ''hydrostatic'' from the requirements for considering M&C-related defects stable because any strength test that is approved in subpart J should qualify. Further, that public commenter suggested adding language where a pressure reduction or an ILI assessment with an ECA could be allowed for M&C defects as well. Another public commenter suggested removing references to cracks in these sections if PHMSA was intending to create a new section dedicated to addressing crack defects.

Ultimately, the GPAC recommended PHMSA revise the proposed requirements for M&C defects by deleting a cross-reference with the MAOP reconfirmation requirements, updating an applicability reference, and considering removing the term ''hydrostatic'' while allowing other authorized testing procedures. For the requirements related to electric resistance welded (ERW) pipe, the GPAC recommended PHMSA delete the phrase related to pipe body cracking and have those requirements be addressed in a new section within the IM regulations related to crack defects.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the consideration of seismicity and manufacturing- and construction-related defects under the IM regulations. After considering these comments as well as recommendations by the GPAC, PHMSA is revising § 192.917(e)(2) to require operators monitor operating pressure cycles and periodically determine if the cyclic fatigue analysis is valid at least once every 7 calendar years, not to exceed 90 months, as necessary. PHMSA is also deleting a reference to the MAOP reconfirmation requirements in § 192.624 and is referencing the new § 192.712 for fracture mechanics analysis. PHMSA believes these changes are consistent with current IM requirements and will increase regulatory flexibility while maintaining pipeline safety.

In § 192.917(e)(3), PHMSA deleted a cross-reference to the MAOP reconfirmation requirements in § 192.624 and replaced it with a requirement to prioritize the pipeline segment if it has experienced an in-service reportable incident since its most recent successful subpart J pressure test due to an original manufacturing-related defect; or a construction-, installation-, or fabrication-related defect. This clarifies that the IM requirement in § 192.917(e)(3) is not part of the MAOP reconfirmation standards. Although the GPAC asked PHMSA to consider removing the term ''hydrostatic'' and allow other testing procedures, PHMSA is retaining the term ''hydrostatic'' in § 192.917(e)(3), as the proposed revision, as written, addresses NTSB recommendation P–11–15. The NTSB specifically recommended that PHMSA amend part 192 so that manufacturing- and construction-related defects can only be considered stable following a postconstruction hydrostatic pressure test of at least 1.25 times the MAOP. Therefore, deleting the word ''hydrostatic'' would be contrary to the letter and intent of this NTSB recommendation.

For the requirements related to ERW pipe in § 192.917(e)(4), PHMSA has deleted the phrase related to pipe body cracking and deleted a cross-reference to the MAOP reconfirmation requirements in § 192.624, referencing the new § 192.712 for fracture mechanics analysis instead for cracking and crack-related issues. PHMSA made these changes to streamline the regulations and increase readability.

D. 6-Month Grace Period for 7-Calendar-Year Reassessment Intervals—§ 192.939

1. Summary of PHMSA's Proposal

Section 5 of the 2011 Pipeline Safety Act identifies a technical correction amending 49 U.S.C. 60109(c)(3)(B) to allow the Secretary of Transportation to extend the 7-calendar-year IM reassessment interval for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. The NPRM proposed to codify this technical correction as required by the statute.

2. Summary of Public Comment

PHMSA received a comment regarding the 6-month grace period for the 7-calendar-year reassessment interval from a trade organization expressing general support of the proposed provisions and requesting that PHMSA clarify that the 6-month extension begins after the close of the 7-calendar-year reassessment interval period, which would be consistent with

the 2011 Pipeline Safety Act revision to the Federal Pipeline Safety Statutes.

At the GPAC meeting on January 12, 2017, the GPAC voted that the proposed changes on the 6-month grace period for the reassessment intervals are technically feasible, reasonable, cost-effective, and practicable, and did not recommend that PHMSA modify these proposed provisions.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the grace period for IM reassessment intervals. After considering the comment and as recommended by the GPAC, PHMSA is retaining the proposed revisions to § 192.939 in this final rule. The proposed rule clearly stated that the 6-month extension begins after the close of the 7-calendar-year reassessment interval period. This is mirrored in PHMSA's frequently asked questions (FAQ) for the IM program,[72] which clarifies that the maximum interval for reassessment may be set using the specified number of calendar years in accordance with the 2011 Pipeline Safety Act. The use of calendar years is specific to gas pipeline reassessment interval years under IM and does not alter the interval requirements that appear elsewhere in the code for various inspection and maintenance requirements.

E. ILI Launcher and Receiver Safety—§ 192.750

1. Summary of PHMSA's Proposal

PHMSA determined that more explicit safety requirements are needed when performing maintenance activities that use launchers and receivers for inserting and removing ILI maintenance tools and devices. The current regulations for hazardous liquid pipelines under part 195 have, since 1981, contained safety requirements for scraper and sphere facilities. However, the current regulations for natural gas transmission pipelines do not similarly require controls or instrumentation to protect against an inadvertent breach of system integrity due to the incorrect operation of launchers and receivers for ILI tools, or scraper and sphere facilities. As a result, PHMSA proposed to add a new section to the Federal Pipeline Safety Regulations to require ILI launchers and receivers include a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the barrel or a means to prevent opening if pressure has not been relieved. While most launchers and receivers are already equipped with such devices, some older facilities may not be so equipped. Under the proposed provisions, operators would be required to have this safety equipment installed consistent with current industry practice.

2. Summary of Public Comment

Stakeholders, including TPA, provided input on PHMSA's changes to the requirements for safety when performing maintenance activities that utilize launchers and receivers for inserting and removing inspection and maintenance tools and devices. TPA supported the proposed safety additions to the regulations but stated that § 192.750 should be included within the regulations for pipeline components rather than the subpart for pipeline maintenance. In addition, TPA suggested PHMSA revise the language to allow 18 months after the effective date of the rule to comply with the provisions. This change would allow for more time to plan, budget, and complete the work safely. Another commenter recommended these provisions be effective prior to the next time an operator would use an applicable launcher or receiver. Public interest groups and others, such as PST and NAPSR, had broad support for the proposed provisions regarding ILI launcher and receiver safety.

At the GPAC meeting on January 12, 2017, a public commenter suggested clarification on PHMSA's use of the term ''relief device'' or ''relief valve'' within the proposed provisions. During discussion, the committee noted that there are requirements for ''relief valves'' elsewhere in the code, and calling a needed safety device for ILI launchers and receivers a ''relief valve'' would then make it subject to those additional requirements. Based on that discussion, the committee recommended that PHMSA modify the proposed rule to clarify that the rule does not require ''relief valves'' or use ''relief valve'' as an officially defined term within the provision, as those terms have distinct meanings within the broader context of the Federal Pipeline Safety Regulations.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding launcher and receiver safety. After considering these comments and the GPAC input, PHMSA is finalizing the provisions as they were proposed in the NPRM, with the exception of a compliance date 1 year after the effective date of the rule. This approach avoids disruption of work planned within a year of the effective date of the rule, and it allows operators that are not planning work until beyond the 1-year grace period to implement the upgrade before the next planned use. Therefore, special modification work would not be required before the launcher or receiver is needed. Operators would not be required to perform the upgrades until the launcher or receiver is to be used.

Consistent with the originally proposed language, this final rule does not use the term ''relief valve'' and instead uses the generic phrase ''device capable of safely relieving pressure.'' The proposed rule effectively avoided any potential for confusion with respect to the defined term ''relief valve'' and the requirements associated with those components, therefore no change to this wording was necessary for this final rule.

PHMSA believes that this requirement is appropriately located in subpart M, ''Maintenance,'' of part 192, and notes that the comparable requirement in part 195 for hazardous liquid pipelines is located in subpart F, ''Operations and Maintenance.''

F. MAOP Exceedance Reporting—§§ 191.23, 191.25

1. Summary of PHMSA's Proposal

Section 23 of the 2011 Pipeline Safety Act requires that operators report each exceedance of a pipeline's MAOP beyond the build-up allowed for the operation of pressure-limiting or control devices. On December 21, 2012 (77 FR 75699), PHMSA published Advisory Bulletin ADB–2012–11 to advise operators of their responsibility under section 23 of the 2011 Pipeline Safety Act to report such exceedances. The advisory bulletin further stated that the reporting requirement is applicable to all gas transmission pipeline facility owners and operators. PHMSA advised pipeline owners and operators to submit this information in the same manner as safety-related condition reports. The information pipeline owners and operators submit should comport with the information listed at § 191.25(b), and pipeline owners and operators submitting such information should use the reporting methods listed at § 191.25(a).

Although this provision of the 2011 Pipeline Safety Act is self-executing, PHMSA proposed to revise the safety-related condition reporting requirements under part 191 to codify this requirement and harmonize part 191 with the statutory requirement by eliminating the reporting exemption and to provide a consistent procedure,

[72] FAQ–41 at *https://primis.phmsa.dot.gov/gasimp/faqs.htm.*

format, and structure for operators to submit such reports.

2. Summary of Public Comment

Trade associations, citizen groups, and pipeline industries generally supported PHMSA's codification of the statutory reporting requirements for MAOP exceedances for transmission lines.

API and GPA objected to MAOP exceedance reporting requirements for unregulated gathering pipelines. GPA stated that PHMSA did not sufficiently weigh the benefits of reporting MAOP exceedance against the hurdles to compliance for unregulated gathering pipelines. GPA also questioned whether PHMSA has the authority to require unregulated gathering pipelines report MAOP exceedance, since complying with this reporting requirement would necessitate that unregulated gathering pipelines establish MAOP, which they are currently not required to do. Citizen and other safety groups, including Earthworks, NAPSR, the Pipeline Safety Coalition, and PST, supported the inclusion of unregulated gathering pipelines in this section, stating that it would improve pipeline safety.

Several commenters suggested editorial revisions to streamline and improve these provisions. NGA expressed concern that the proposed provisions could apply to distribution systems and suggested that PHMSA clarify that reporting requirements for MAOP exceedance only apply to transmission pipelines. Additionally, Spectra Energy Partners requested that PHMSA require reporting of MAOP exceedances only when the operator is unable to respond to MAOP exceedances within the timeframe required elsewhere in part 192.

One operator expressed concern that the proposed change would require operators to submit additional safety-related condition reports anytime the operator had to implement a pressure reduction upon discovering an immediate condition.

At the GPAC meeting on June 7, 2017, there was brief discussion on whether the 5-day reporting requirement was too prescriptive, but the committee agreed that PHMSA was properly implementing the statutory requirement as written and intended by Congress. Following that discussion, the committee recommended that PHMSA modify the proposed rule to clarify that the MAOP exceedance reporting provisions do not apply to gathering lines.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding MAOP exceedance reporting. The 2011 Pipeline Safety Act mandates that an operator report MAOP exceedances on gas transmission lines, regardless of whether the operator corrects the safety-related condition through repair or replacement. After considering the comments PHMSA received on the NPRM and as recommended by the GPAC, PHMSA is inserting the word ''only'' in the additional MAOP exceedance reporting provision in § 191.23(a)(10) to make it clearer that the amended requirement applies only to gas transmission lines and not to gathering or distribution lines. Conforming changes were made to § 191.23(a)(6). PHMSA notes that the prior safety-related condition reporting requirements and exceptions related to pressure exceedances for gathering and distribution lines have not been altered.

G. Strengthening Assessment Requirements—§§ 192.150, 192.493, 192.921, 192.937, Appendix F

i. Industry Standards for ILI—§§ 192.150, 192.493

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to revise § 192.150 to incorporate by reference a NACE Standard Practice, NACE SP0102–2010, ''In-line Inspection of Pipelines,'' to promote a higher level of safety by establishing consistent standards for the design and construction of pipelines to accommodate ILI devices.

In § 192.493, PHMSA proposed requirements for operators to comply with the requirements and recommendations of API STD 1163, In-line Inspection Systems Qualification Standard; ANSI/ASNT ILI–PQ–2005, In-line Inspection Personnel Qualification and Certification; and NACE SP0102–2010, In-line Inspection of Pipelines. PHMSA also proposed to allow operators to conduct assessments using tethered or remotely controlled tools.

2. Summary of Public Comment

NAPSR supported the proposed provisions in § 192.493, commenting that the incorporation by reference of the three consensus standards provides enhanced guidance for the determination of adequate procedures and qualifications related to in-line inspections of transmission pipelines.

Some industry representatives commented that it is unnecessary to incorporate American Society for Nondestructive Testing (ASNT) ILI–PQ by reference since API 1163 requires that providers of ILI services ensure that their employees are qualified. Others commented that PHMSA should exclude requirements contained in section 11 of API 1163, which pertains to quality management systems. Lastly, industry representatives asserted that ILI vendors may not be able to meet the 90 percent tool tolerance specified in the referenced standards, and PHMSA should relocate these proposed requirements to a different subpart.

Several commenters noted that if PHMSA required compliance with ''the requirements and recommendations of'' the recommended practices and standards, it would create enforceable requirements out of actions that the standards themselves did not necessarily mandate.

During the GPAC meeting of March 2, 2018, the committee recommended PHMSA revise this provision by striking the phrase ''the requirements and the recommendations of,'' so that recommendations within the incorporated standard would not be made mandatory requirements.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the incorporation by reference of industry standards for ILI. After considering these comments and as recommended by the GPAC, PHMSA is deleting the phrase ''the requirements and the recommendations of'' from §§ 192.150 and 192.493 so that the recommendations within the incorporated standard would not be made mandatory requirements.

PHMSA believes that the inclusion of the NACE standard at § 192.150 will help to address the NTSB recommendation P–15–20, which asked PHMSA to identify all operational complications that limit the use of ILI tools in piggable pipelines, develop methods to eliminate those complications, and require operators use such methods to increase the use of ILI tools. PHMSA also believes that more pipelines will become piggable in the future as the nation's pipeline infrastructure ages and is eventually replaced. A current provision in the regulations requires that all new and replaced pipeline be piggable, and as operators address higher-risk infrastructure through this rulemaking, there is a likelihood that some previously unpiggable pipe will be replaced.

PHMSA disagrees that ASNT ILI–PQ is unnecessary. The foreword of API 1163 states ''*This standard serves as an umbrella document to be used with and complement companion standards.*

NACE SP0102, In-line Inspection of Pipelines and ASNT ILI–PQ, In-line Inspection Personnel Qualification and Certification.'' These three standards are complimentary and are intended to be used together. PHMSA also disagrees that quality requirements should be excluded from the rule. One of the fundamental objectives of this rule is to establish a minimum standard for quality in conducting ILI. Also, the consensus industry standard API 1163 only uses 90 percent tool tolerance as an example to illustrate key points but does not specify or establish a minimum standard tool tolerance of 90 percent.

G. Strengthening Assessment Requirements—§§ 192.150, 192.493, 192.921, 192.937, Appendix F

ii. Expand Assessment Methods Allowed for IM—§§ 192.921(a) and 192.937(c)

1. Summary of PHMSA's Proposal

In the current Federal Pipeline Safety Regulations, § 192.921 requires that operators with pipelines subject to the IM rules must perform integrity assessments. Currently, operators can assess their pipelines using ILI, pressure test, direct assessment, and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline.

In the NPRM, PHMSA proposed to require that direct assessment only be allowed when the pipeline cannot be assessed using ILI. As a practical matter, direct assessment is typically not chosen as the assessment method if the pipeline can be assessed using ILI. Further, PHMSA proposed to add three additional assessment methods to the regulations:

1. A spike hydrostatic pressure test, which is particularly well-suited to address stress corrosion cracking and other cracking or crack-like defects;

2. Guided Wave Ultrasonic Testing (GWUT), which is particularly appropriate in cases where short segments such as road or railroad crossings are difficult to assess; and

3. Excavation with direct *in situ* examination.

2. Summary of Public Comment

NAPSR expressed its support for the proposed provisions. Many comments expressed concerns with the proposed provisions for the assessment methods regarding uncertainties in reported results. Multiple commenters stated that operators should be able to run the appropriate assessment or ILI tools for the threats that are known or likely to exist on the pipeline based on its condition. Atmos Energy commented that ASME/ANSI B318.S requirements should be the standard to which operators are required to follow. Enable Midstream Partners proposed that PHMSA add ''significant'' to make a distinction between significant and insignificant threats and offered specific language to address its concerns. PG&E commented on the proposed provisions for ILI assessments, requesting that PHMSA provide guidance as to how to explicitly consider the numerous uncertainties associated with ILI regarding anomaly location accuracy, detection thresholds, and sizing accuracy, and suggested that PHMSA allow industry guidance and best practices to be used where practical. Some commenters expressed concern that PHMSA proposed to add requirements surrounding the detection of anomalies that many ILI tools could not meet. These commenters stated that there are no tools designed to find girth weld cracks and that most incidents caused by girth weld cracks have third-party excavation damage as a contributing factor. Commenters further stated that this is a threat that is best handled by procedures that require caution around girth welds during excavation and backfilling procedures.

Several entities commented on the proposed qualification requirements under the ILI assessment method provisions, expressing concern that they are redundant with existing operator qualification regulations under the IM regulations at § 192.915 and the proposed revisions to § 192.493 incorporating the industry ANSI standard on ILI personnel qualification. Multiple entities proposed changes to remove such redundancies and improve clarity.

Commenters requested clarification that the proposed text in the IM assessment provisions ''apply one or more of the following methods for each threat to which the covered segment is susceptible'' does not mean that at least one assessment is required for each threat. Additionally, commenters disagreed with adding an explicit requirement for a ''no objection'' letter as notification of using ''other technology'' and suggested that if this notification is required, operators should be allowed to proceed with the technology if they do not receive a ''no objection'' letter from PHMSA within a certain period.

The NTSB commented that PHMSA's proposal to revise the pipeline inspection requirements to allow the direct assessment method to be used only if a line is not capable of inspection by internal inspection tools directly conflicts with the recommendations of their pipeline safety study, *Integrity Management of Gas Transmission Lines in High Consequence Areas,* which recommended that PHMSA develop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines. The CPUC asserted that direct assessment must always be supplemented with other methods, such as ILI or a pressure test.

Many industry entities argued that PHMSA's proposed changes to the IM assessment provisions limiting direct assessment to unpiggable lines are not technically justified. Several entities, including AGA and API, believed it was unreasonable to limit operators' ability to use direct assessment for pipeline assessments unless all other assessment methods have been determined unfeasible or impractical. PG&E requested that PHMSA recognize that although a pipeline may be considered piggable, it does not mean that ILI technology is available, and they provided specific suggestions for revision. Similarly, AGA stated that free-swimming flow-driven ILI tools are often not compatible with intrastate transmission lines for several reasons, stating that certain conditions must exist to assess a pipeline by ILI and obtain valid data, including adequate flow rate, lack of bends or valves that would impede diameter, and ability to insert and remove the tool from the system. Therefore, AGA provided a suggested definition for ''able to accommodate inspection by means of an instrumented in-line inspection tool.''

Trade associations asserted that direct assessment is a proven assessment technique that works in addressing the threat of corrosion. INGAA stated that the criteria for when direct assessment can be used should depend on whether direct assessment can provide the necessary information about the pipe condition rather than whether other assessment methods can be used. AGA commented that it is not aware of any industry study that would suggest that direct assessment does not work effectively to identify corrosion defects in certain circumstances, which it describes in its comments. In addition, AGA stated that direct assessment is a predictive tool that identifies areas where corrosion could occur, including time-dependent threats, while other methods can only detect where corrosion has resulted in a measurable metal loss. Atmos Energy commented that limiting the use of direct assessment only to those pipeline segments that are not capable of

inspection by internal inspection tools is not consistent with other requirements of subpart O.

At the GPAC meeting on December 15, 2017, the committee voted to revise the ''no objection'' process to incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. Additionally, the GPAC, during the meeting on March 2, 2018, recommended that PHMSA change these provisions to clarify that operators should select the appropriate assessment based on the threats to which the pipeline is susceptible and remove certain language that is duplicative to another existing section of the regulations. The GPAC also recommended that PHMSA clarify that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable. Further, the GPAC wanted PHMSA to incorporate the notification and objection procedure and 90-day timeframe that the GPAC approved under the material properties verification requirements.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the inclusion of additional assessment methods for integrity assessments. After considering these comments and as recommended by the GPAC, PHMSA is clarifying in this final rule that operators should select the appropriate assessment method based on the threats to which the pipeline is susceptible and is removing language regarding the qualification of persons reviewing ILI results that is duplicative with existing § 192.915. PHMSA is also clarifying in § 192.921 that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable, such as assessing pipe seam threats. In addition, PHMSA incorporated the notification procedure under § 192.18 with the 90-day timeframe and objection process.

PHMSA notes that other comments regarding the determination of suitable assessment methods for applicable threats and ILI tool capabilities relate to long-standing IM regulations that were not proposed for revision. PHMSA did provide substantial additional guidance and standards for implementing the integrity assessment requirements for ILI by incorporating the industry standards in § 192.493, as discussed in the previous sections.

G. Strengthening Assessment Requirements—§§ 192.150, 192.493, 192.921, 192.937, Appendix F

iii. Guided Wave Ultrasonic Testing—Appendix F

1. Summary of PHMSA's Proposal

When expanding assessment methods for both HCA and non-HCA areas, PHMSA proposed to add three additional assessment methods, one being GWUT. Under the existing regulations, GWUT is considered ''other technology,'' and operators must notify PHMSA prior to its use. PHMSA developed guidelines for the use of GWUT, which have proven successful, and proposed to add them under a new Appendix F to part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing. As such, future notifications to PHMSA would not be required, representing a cost savings for operators.

2. Summary of Public Comment

Multiple entities commented in support of using GWUT and the inclusion of proposed Appendix F. NAPSR expressed its agreement with and support for the proposed Appendix. American Public Gas Association (APGA) applauded PHMSA for including guidelines for GWUT; however, it cautioned that the guidance only specifies Guided Ultrasonics LTD (GUL) Wavemaker G3 and G4, which use piezoelectric transducer technology, as acceptable technology. APGA recommended that Magnetostrictive Sensor technology also be included as an acceptable guided wave technology, stating that at least one of its members reported good results using this technology for guided wave assessment of an unpiggable segment of a transmission pipeline.

A commenter noted that the requirement of both torsional and longitudinal wave modes in all situations introduces unnecessary complexity into the GWUT data interpretation process. The commenter further noted that PHMSA should specify that torsional wave mode is the primary wave mode when utilizing GWUT, and that longitudinal wave mode may be used as an optional, secondary mode. Other commenters recommended additional changes to Appendix F, such as stating that qualified GWUT equipment operators are trained to understand the strengths, weaknesses, and proper applications of each wave mode and should have the freedom to select the appropriate and most effective wave mode(s) for the given situation. PG&E requested that PHMSA recognize that this technology is used at locations other than casings as implied in the introductory paragraph and commented that double-ended inspections are not always required to meet the specification.

During the GPAC meeting on December 15, 2017, the GPAC agreed with the provisions related to Appendix F and GWUT but recommended PHMSA revise the ''no objection'' letter process.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding GWUT. After considering these comments and as recommended by the GPAC, PHMSA is removing the reference to GUL equipment for clarity. PHMSA is modifying the notification process to allow operators to proceed with an alternative process for using GWUT if the operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA in accordance with § 192.18. PHMSA believes this change increases regulatory flexibility while maintaining pipeline safety.

In this final rule, PHMSA is retaining the requirement to use both torsional and longitudinal wave modes since that is a long-standing requirement in PHMSA's guidance for accepting GWUT as an allowed technology under an ''other technology'' notification. Also, PHMSA recognizes that GWUT is used at locations other than casings, although it is most often deployed for the integrity assessment of cased crossings. However, double-ended inspections would not always be required to meet Appendix F, and Appendix F does not require double-ended inspections. Double-ended inspections are not necessary as long as the guided wave ultrasonic test covers the entire length of the assessment as well as the ''dead zone'' where the equipment is set up.

The proposed rule already addresses validation of operator training, but in this final rule, PHMSA is deleting the sentence ''[t]here is no industry standard for qualifying GWUT service providers'' to provide clarity.

H. Assessing Areas Outside of HCAs—§§ 192.3, 192.710

i. MCA Definition—§ 192.3

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA introduced a new definition for a Moderate Consequence Area (MCA). The proposed rule defined an MCA as an onshore area, not meeting the definition of an HCA, that is within a potential impact circle, as defined in § 192.903, containing 5 or more buildings intended

for human occupancy; an occupied site; or a right-of-way for a designated interstate, freeway, expressway, or other principal four-lane arterial roadway as defined in the Federal Highway Administration's ''Highway Functional Classification Concepts, Criteria and Procedures.'' PHMSA proposed that requirements for data analysis, assessment methods, and immediate repair conditions within these MCAs would be similar to requirements for HCA pipeline segments but with longer timeframes so that operators could properly allocate resources to higher-consequence areas. PHMSA proposed that the 1-year repair conditions that currently exist for HCA pipeline segments would be 2-year repair conditions when found on MCA pipeline segments. These changes would ensure the prompt remediation of anomalous conditions that could potentially affect people, property, or the environment, commensurate with the severity of the defects, while still allowing operators to allocate their resources to HCAs on a higher-priority basis.

2. Summary of Public Comment

The NTSB stated that the proposed provisions to create an MCA category and include a highway size threshold in the definition of an MCA accomplishes part of what the NTSB intended in Safety Recommendation P–14–1. However, the NTSB objected to the proposed highway coverage as being limited to four lanes and stated its support of expanding the highway size threshold as they had specifically recommended in P–14–1. The NTSB asserted that the proposed language would exclude the category of other principal arterial roadways wider than four lanes when, in fact, the wider roadways should be included.

INGAA supported the addition of an MCA category to the Federal Pipeline Safety Regulations but recommended several modifications to the proposed definition. INGAA suggested PHMSA should limit the definition of an MCA to only those pipeline segments that could be assessed through an ILI inspection, amend the MCA definition to avoid ambiguity regarding residential structures, remove ''outside areas and open structures'' from the portion of the definition of MCA related to ''identified sites,'' include timeframes for incorporating changes to existing MCAs, and permit operators to use the edge of the pavement rather than the highway right-of-way to determine if a roadway intersects with a Potential Impact Circle.

AGA, API, APGA, and several pipeline entities agreed with INGAA's comments on the modification to PHMSA's proposed MCA definition. Additionally, AGA, API, and APGA emphasized PHMSA should remove the reference to ''a right-of-way'' for the designated roadways, commenting that the MCA definition could be interpreted so that if a Potential Impact Circle touches any portion of the roadway right-of-way, the pipeline segment is an MCA. That interpretation would put undue burden on operators in areas where its pipelines lay at or near the edge of the public right-of-way that would not normally contain ''persons or property'' that would sustain damage or loss in the event of a pipeline failure. Further, API added that the reference to ''a right-of-way'' is problematic because roadway right-of-ways are variable, cannot be seen with the naked eye, and are often not included in publicly available data sources.

Commenters also disagreed with the definition of ''occupied site'' within the MCA definition. GPA asserted that the criterion used in the MCA definition should be limited to interstate highways, and the definition of ''occupied site'' should be eliminated to more clearly distinguish between MCAs and HCAs and to provide greater clarity in identifying and managing MCAs. Similarly, Enlink Midstream commented that PHMSA should eliminate the definition of occupied site and remove this criterion from the proposed definition of MCA. Doing so would permit the continued focus on HCAs that the IM process was intended to accomplish. AGL Resources also expressed concern with the proposed definition of occupied site, commenting that this definition could require operators to effectively perform a census-like identification of structures to verify the count of persons within that structure.

There were conflicting viewpoints on where the definition of MCA should be placed in the regulations. API and other commenters stated that they preferred a new category and a distinct definition for MCA as opposed to expanding the definition of HCA or making a subcategory in the HCA definition for MCAs, whereas SoCalGas encouraged expanding the scope of HCAs rather than creating a new category.

Enterprise Products commented PHMSA should move the MCA definition to subpart O and remove the ''occupied site'' criteria from the proposed definition of MCA, which would provide more distinction between MCAs and HCAs in the regulations and would also more appropriately place them under the IM regulations.

AGA and several other organizations expressed concern over the resource-intensive administrative task of identifying MCAs, especially pertaining to recordkeeping requirements. API asserted that the proposed provisions would limit operators' ability to prioritize resources for pipelines that pose the highest risk. They further stated that while they agree with the inclusion of all Class 3 and Class 4 locations, occupied sites, and major roadways in the definition of MCA, they disagree with the proposed threshold of five buildings intended for human occupancy within the potential impact radius. They suggested that a more appropriate threshold would be more than 10 buildings intended for human occupancy, as that number is consistent with longstanding part 192 class location designations.

Multiple groups, such as AGI, INGAA, and Cheniere Energy, also stated objections over various aspects of defining and identifying MCAs and provided suggestions for revised language, including several broad clarifications or deletions to the definition. In addition to requesting modifications to the definition of MCA, INGAA objected to the provided geographic information system (GIS) layer for right-of-way determination, and suggested that PHMSA provide one database for roadway classification. Numerous trade associations and pipeline companies asked PHMSA to consider a qualifier that the definition of MCA only applies to pipelines operating at greater than 30 percent SMYS. EnLink Midstream suggested using a threshold level of 16-inch pipe diameter to identify pipelines that pose a greater risk.

The GPAC had a comprehensive discussion on the MCA definition during the meeting on March 2, 2018, and approved of the definition with some changes. First, the GPAC recommended changing the highway description within the definition to remove reference to the roadway ''rights-of-way'' and to add language so that the highway consists of ''any portion of the paved surface, including shoulders.'' Secondly, the GPAC recommended clarifying that highways with 4 or more lanes are included, and they also wanted PHMSA to work together with the Federal Highway Administration to provide operators with clear information relative to this aspect of the rulemaking and discuss it in the preamble. The GPAC also recommended that PHMSA discuss in the preamble what they expect the definition of ''piggable'' to be, as it is critical for aspects of the MCA

definition as it relates to MAOP confirmation. Finally, the GPAC recommended PHMSA modify the term ''occupied sites'' in the MCA definition and in the definitions section of part 192 by removing the language referring to ''5 or more persons'' and the timeframe of 50 days and tying the requirement into the HCA survey for ''identified sites'' as discussed by GPAC members and PHMSA at the meeting. The committee noted that such site identification could be made through publicly available databases and class location surveys. The committee suggested PHMSA consider the necessary sites and enforceability of the definition per direction by the committee members.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the definition of moderate consequence area. After considering these comments and the GPAC input, PHMSA is modifying the highway description within the definition to remove reference to the roadway ''rights-of-way'' and to add language so that the highway consists of ''any portion of the paved surface, including shoulders.'' Also, PHMSA is specifying that highways with 4 or more lanes are included. PHMSA believes these changes provide additional clarity.

Per the GPAC's request that PHMSA provide additional guidance on what roadways are included in the MCA definition as it pertains to ''other principal roadways with 4 or more lanes,'' PHMSA notes that the Federal Highway Administration defines *Other Principal Arterial* roadways [73] as those roadways that serve major centers of metropolitan areas, provide a high degree of mobility, and can also provide mobility through rural areas. Unlike their access-controlled counterparts (interstates, freeways, and expressways), abutting land uses can be served directly. Forms of access for *Other Principal Arterial* roadways include driveways to specific parcels and at-grade intersections with other roadways. For the most part, roadways that fall into the top three functional classification categories (Interstate, Other Freeways & Expressways, and Other Principal Arterials) provide similar service in both urban and rural areas. The primary difference is that there are usually multiple arterial routes serving a particular urban area, radiating out from the urban center to serve the surrounding region. In contrast, an expanse of a rural area of equal size would be served by a single arterial. The MCA definition does not include all roadways that meet this definition but instead is limited to those roadways meeting this definition that have four or more lanes.

With respect to ''occupied sites,'' PHMSA evaluated the comments and the GPAC discussion and concluded that including occupied sites within the MCA definition was not necessary. Industry representatives on the GPAC asserted that most locations meeting the definition of occupied site are, as a practical matter, already included as an identified site and designated as an HCA. Commenters suggested most operators find it expedient to declare sites similar to occupied areas as HCAs instead of counting the specific occupancy of such locations to see if they meet the occupancy standard over the course of a year. Operators then monitor occupancy in subsequent years for changes that might change the site's status as an occupied site. Such an approach would require fewer resources and be more conservative from a public safety standpoint. Based on these comments, PHMSA is persuaded that including another category of locations, similar to identified sites in HCAs but with a lower occupancy standard of 5 persons, is unnecessarily burdensome without a comparable decrease in risk.

PHMSA disagrees that the MCA definition should be moved to subpart O. The term is used in sections outside of subpart O. Including the MCA definition in § 192.3 is necessary for it to apply to the sections in which it is used throughout part 192.

H. Assessing Areas Outside of HCAs—§§ 192.3, 192.710

ii. Non-HCA Assessments—§ 192.710

1. Summary of PHMSA's Proposal

PHMSA proposed to add a new § 192.710 to require that pipeline segments in Class 3 or Class 4 locations, and piggable segments in MCAs, be initially assessed within 15 years and no later than every 20 years thereafter on a recurring basis. PHMSA also proposed to require assessments in these areas be conducted using the same methods that are currently allowed for HCAs. PHMSA has found that operators have assessed significant non-HCA pipeline mileage in conjunction with performing HCA integrity assessments in the same pipeline. Therefore, PHMSA proposed to allow the use of those prior assessments of non-HCA pipeline segments to comply with the new § 192.710.

In effect, to this limited population of pipeline segments outside of HCAs, PHMSA proposed to expand the applicability of IM program elements related to baseline integrity assessments, remediating conditions found during integrity assessments, and periodic reassessments. In addition, under the proposed provisions, MCAs would be subject to other requirements related to the congressional mandates, including material properties verification and MAOP reconfirmation. Any assessments an operator would conduct to reconfirm MAOP under proposed § 192.624 would count as an initial assessment or re-assessment, as applicable, under the proposed requirements for non-HCA assessments.

2. Summary of Public Comment

The NTSB and multiple citizen groups supported the expansion of IM elements to gas transmission pipelines in areas outside those currently defined as HCAs. However, several entities, including PST, stated that applying a limited suite of IM tools to these areas was insufficient and requested that the full suite of IM elements be applied to the additional pipeline segments. Some citizen groups expressed concern that the 15-year implementation period and 20-year re-inspection period was too long.

While pipeline companies and trade associations generally supported PHMSA's efforts to expand IM elements beyond HCAs, many of them stated concerns over the time and cost required to identify MCAs, the efficacy of the changes, and the language and requirements regarding both the limitation of assessments to pipeline segments accommodating inline inspection tools and (re)assessment periods. Many groups requested a clear, concise set of codified requirements for IM outside of HCAs to simplify identification, recordkeeping, and repairs.

Several commenters provided input on the allowable assessment methods for non-HCAs. AGA suggested that PHMSA create a new subpart consisting of a clear and concise set of codified requirements for the non-HCA assessments, including new definitions regarding the limitation of assessments to pipeline segments accommodating instrumented inline inspection tools. Many trade associations and pipeline companies stated that they thought the direct assessment method could achieve a satisfactory level of inspection in place of costlier in-line inspection,

[73] Federal Highway Administration, Office of Planning, Environment, & Realty (HEP), *Highway Functional Classification Concepts, Criteria and Procedures (2013) https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/section03.cfm#Toc336872980.*

especially given the additional detail added to the in-line inspection assessment method in the proposal. API requested that PHMSA allow operators to rely on any prior assessments performed under subpart O requirements of part 192 in effect at the time of the assessment rather than limit the allowance to ILI. Furthermore, other organizations supported AGA's proposal that mirrors and extends to MCAs the two-methodology approach used to determine HCAs in the existing § 192.903, which allows for identification based on class location or by the pipeline's potential impact radius.

Entities, including API and Atmos Energy, requested clarification regarding assessment periods and reassessment intervals due to the language regarding shorter reassessment intervals ''based on the type [of] anomaly, operational, material and environmental conditions [. . .], or as otherwise necessary.'' Those commenters said that language was vague and subject to varying interpretations, so they suggested revisions to the language for the reassessment intervals. Lastly, AGA suggested that PHMSA define the term ''pipelines that can accommodate inspection by means of an instrumented in-line inspection tool'' used in proposed §§ 192.710 and 192.624, stating that providing the criteria that a pipeline must meet to be able to accommodate an in-line inspection tool would remove uncertainty and inconsistency in determining which pipelines meet PHMSA's proposed qualifier.

The GPAC discussed the provisions related to assessments outside of HCAs during the meeting on March 2, 2018. The GPAC found the provisions to be technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that direct assessment could be used only if appropriate for the threat being assessed and could not be used to assess threats for which direct assessment is not suitable, and removed the provisions related to low-stress assessments. The GPAC also recommended revising the initial assessment and reassessment intervals for applicable pipeline segments from an initial assessment within 15 years of the effective date of the rule and periodic assessments every 20 years thereafter to an initial assessment within 14 years of the effective date of the rule and periodic assessments every 10 years thereafter. The GPAC stated that the prioritization of initial assessments and reassessments should be based on the risk profiles of the pipelines. The GPAC also wanted PHMSA to apply the assessment and reassessment requirements only to pipelines with MAOPs greater than or equal to 30 percent SMYS.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding integrity assessments outside HCAs. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to specify that direct assessment may be used only if appropriate for the threat being assessed and cannot be used to assess threats for which direct assessment is not suitable, such as assessing pipe seam threats. PHMSA made these changes to provide clarity regarding the proper use of direct assessments.

In addition, PHMSA is revising the applicability of § 192.710 to apply only to pipelines with an MAOP of greater than or equal to 30 percent of SMYS. PHMSA made this change because the GPAC recommended it was cost-effective for the provision to only apply to pipe operating above 30% SMYS in Class 3 and 4 locations and because those pipelines present the greatest risk to safety. Because of this modification, PHMSA is withdrawing provisions related to low-stress assessments since they will no longer be applicable.

Based on the comments and recommendations from the GPAC, PHMSA is also modifying the initial assessment deadline and reassessment intervals for applicable pipeline segments to 14 years after the publication date of the rule and every 10 years thereafter, which was reduced from 15 years and 20 years, respectively. PHMSA believes this change increases regulatory flexibility while maintaining pipeline safety. PHMSA is also adding a requirement that the initial assessments must be scheduled using a risk-based prioritization.

PHMSA disagrees with the need to implement a dual approach to MCA identification that would be similar to the ways that HCAs are identified. Subpart O and the IM regulations were first promulgated before pipeline operators had experience with potential impact radius (PIR) techniques, and incorporating an alternative HCA identification method into the original IM regulations using conventional class locations was convenient and appropriate. Pipeline operators now have over 15 years of experience working with the PIR concept; therefore, PHMSA determined using the PIR method for determining MCAs in the definition of MCAs is appropriate. PHMSA also disagrees that a separate subpart would be preferable and is retaining the requirements for MCA assessments in a new § 192.710.

PHMSA believes the requirement to have a shorter reassessment interval is clear and is not modifying that aspect of the rule. PHMSA included a requirement for operators to not automatically default to the maximum reassessment interval but to establish shorter reassessment intervals ''based upon the type anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety'' when appropriate. Operators have been required to perform similar analyses and adjustment of reassessment intervals for HCAs since the inception of the IM regulations in 2003 and should be familiar with this process over 15 years later. PHMSA believes that stating the overarching goal of assuring public safety by evaluating each pipeline and its circumstances and establishing appropriate assessment intervals based on those circumstances provides clear intent and is an appropriate approach.

PHMSA believes that the term ''piggable segment'' is very widely understood in the industry and is not including additional definitions or regulatory language to expand upon this term. PHMSA understands that a pipeline segment might be incapable of accommodating an in-line inspection tool for a number of reasons, including but not limited to short radius pipe bends or fittings, valves (reduced port) that would not allow a tool to pass, telescoping line diameters, and a lack of isolation valves for launchers and receivers. Some unpiggable pipelines can be made piggable with modest modifications, but others cannot be made piggable short of pipe replacement.

PHMSA understands that a pipeline segment is piggable if it can accommodate an instrumented ILI tool without the need for major physical or operational modification, other than the normal operational work required by the process of performing the inline inspection. This normal operational work includes segment pigging for internal cleaning, operational pressure and flow adjustments to achieve proper tool velocity, system setup such as valve positioning, installation of temporary launchers and receivers, and usage of proper launcher and receiver length and setup for ILI tools. In addition, a pipeline segment that is not piggable for a particular threat because of limitations in technology such that an ILI tool is not commercially available, might be piggable for other threats. For example, a pipeline that is unable to accommodate a crack tool might be able

to accommodate a conventional MFL or deformation tool, and thus be piggable for those threats. Launcher and receiver lengths are not a reason for a pipeline to be considered unpiggable, since through a minor modification they can be modified to be piggable, and the removal of launchers or receivers from the pipeline segment does not make a pipeline unpiggable either.

I. Miscellaneous Issues

i. Legal Comments

The following section discusses industry comments related to legal and administrative procedure issues with the proposed rule.

Summary of Public Comment

Several commenters asserted that the proposed provisions go beyond PHMSA's statutory authority provided by the 2011 Pipeline Safety Act. Many trade associations and pipeline industry entities stated that PHMSA exceeded the congressional mandates in the proposed provisions by imposing retroactive recordkeeping requirements and retroactive material properties verification requirements. These comments are discussed in more detail in their respective sections above.

Commenters asserted that, in the 2011 Pipeline Safety Act, Congress identified specific factors that PHMSA is required to consider when proposing regulations per the statutory mandates, including whether certain proposed provisions would be economically, technically, and operationally feasible, and that the proposed rule did not adequately address these factors. For example, AGA expressed concerns that PHMSA proposed to adopt NTSB recommendations without independently justifying those provisions based on the specific factors required by Congress or providing the reasoning behind adopting said recommendations.

AGA and INGAA also stated that PHMSA did not adequately consider the impact that the Natural Gas Act of 1968 would have on implementation of the proposed rule. Noting that operators are required to obtain permission from FERC before removing pipelines from service or replacing pipelines, these commenters stated that obtaining permissions could hinder operators from quickly performing required tests and repairs. INGAA and AGA also stated that PHMSA did not consult with FERC and State regulators about implementation timelines for certain provisions, which PHMSA is required to do in accordance with 49 U.S.C. 60139(d)(3) because gas service would be affected by the proposed rule.

PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the statutory authority for the proposed rule. With regard to the comments about imposing retroactive recordkeeping requirements and retroactive material properties verification requirements, PHMSA explained in this document that the final provisions of this rule are prospective and do not create retroactive requirements. This topic is discussed in more detail in the respective sections about recordkeeping and material properties verification.

Pertaining to PHMSA's broader authority, Congress has authorized the Federal regulation of the transportation of gas by pipeline in the Pipeline Safety Laws (49 U.S.C. 60101 *et seq.*) and established the current framework for regulating pipelines transporting gas in the Natural Gas Pipeline Safety Act of 1968, Public Law 90–481. Through these laws, Congress has delegated the DOT the authority to develop, prescribe, and enforce minimum Federal safety standards for the transportation of gas, including natural gas, flammable gas, or toxic or corrosive gas, by pipeline. As required by law, PHMSA has considered whether the provisions of this rule are economically, technically, and operationally feasible and has provided relevant analysis in the Regulatory Impact Analysis and preamble of this rule.

In accordance with section 23 of the 2011 Pipeline Safety Act, PHMSA consulted with the Federal Energy Regulatory Commission and State regulators as appropriate to establish the timeframes for completing MAOP reconfirmation. As a part of this consultation, PHMSA accounted for potential consequences to public safety and the environment while also accounting for minimal costs and service disruptions. Furthermore, PHMSA will note that both a FERC member and a NAPSR member are on the GPAC, providing both input and positive votes that the provisions were technically feasible, reasonable, cost-effective, and practicable if certain changes were made. As previously discussed, PHMSA has taken the GPAC's input into consideration when drafting this final rule and made the according changes to the provisions.

I. Miscellaneous Issues

ii.—Records

1. Summary of PHMSA's Proposal

Many pipeline records are necessary for the correct setting and validation of MAOP, which is critically important for providing an appropriate margin of safety to the public. Much of operator and PHMSA data is obtained through testing and inspection under the existing IM requirements. Section 192.917(b) requires operators to gather pipeline attribute data as listed in ASME/ANSI B31.8S—2004 Edition, section 4, table 1. ASME/ANSI B31.8S—2004 Edition, section 4.1 states:

''*Pipeline operator procedures, operation and maintenance plans, incident information, and other pipeline operator documents specify and require collection of data that are suitable for integrity/risk assessment. Integration of the data elements is essential in order to obtain complete and accurate information needed for an integrity management program. Implementation of the integrity management program will drive the collection and prioritization of additional data elements required to more fully understand and prevent/mitigate pipeline threats.*''

However, despite this requirement, there continue to be data gaps that make it hard to fully understand the risks to and the integrity of the nation's pipeline system. Therefore, PHMSA proposed amendments to the records requirements for part 192, specifically under the general recordkeeping requirements, class location determination records, material mechanical property records, pipe design records, pipeline component records, welder qualification records, and the MAOP reconfirmation provisions.

2. Summary of Public Comment

Several commenters provided input on the proposed amendments to the records requirements for part 192. Several public interest groups, including Pipeline Safety Coalition and PST, supported the increased emphasis on recordkeeping requirements, stating that the requirements are a proactive response to NTSB recommendations and are common-sense business best practices.

Several commenters opposed the proposed provisions providing general recordkeeping requirements for part 192. Commenters asserted that these proposed provisions apply significant new recordkeeping requirements on operators by requiring that operators

document every aspect of part 192 to a higher and impractical standard than before. Commenters also stated that the proposed recordkeeping requirements appear to be retroactive and stated that it would be inappropriate to require operators to document compliance in cases where there have not been requirements to document or retain records in the past. Commenters also asserted that the Pipeline Safety Laws at 49 U.S.C. 60104(b) prohibits PHMSA from applying new safety standards pertaining to design, installation, construction, initial inspection, and initial testing to pipeline facilities already existing when the standard is adopted, and that PHMSA does not have the authority to apply these requirements retroactively. These commenters suggested that even the recordkeeping requirements in these non-retroactive subparts could not be changed under PHMSA's current authority. Subsequently, commenters requested that PHMSA confirm that the proposed general, material, pipe design, and pipeline component recordkeeping requirements would not apply to existing pipelines and that recordkeeping requirements for the qualification of welders and qualifying plastic pipe joint-makers would not apply to completed pipeline projects.

Additionally, several commenters also requested that PHMSA clarify that many of the proposed recordkeeping requirements apply only to gas transmission lines. AGA also expressed concern regarding the proposed reference to material properties verification requirements in the proposed general recordkeeping requirements, which, as written, would also require distribution pipelines without documentation to comply with the proposed material properties verification requirements.

Many commenters opposed the proposed application of the term ''reliable, traceable, verifiable, and complete'' in part 192 beyond the requirements for MAOP records, and AGA recommended the deletion of ''reliable, traceable, verifiable and complete'' from proposed provisions under MAOP reconfirmation. Similarly, other commenters, including INGAA, recommended omitting ''reliable'' from the phrase and provided a suggested definition for ''traceable, verifiable, and complete'' records. Additionally, commenters opposed the use of this term in the general recordkeeping requirements at § 192.13, stating that it would apply a new standard of documentation to part 192. Citing a 2012 PHMSA Advisory Bulletin in which PHMSA stated that verifiable records are those ''in which information is confirmed by other complementary, but separate, documentation,'' INGAA requested that PHMSA acknowledge that a stand-alone record will suffice and a complementary record is only necessary for cases in which the operator is missing an element of a traceable or complete record.[74] INGAA also provided examples of records that they believed to be acceptable, and requested that PHMSA includes these examples in the final preamble.

Several commenters also opposed the proposed Appendix A to part 192 that summarizes the records requirements within part 192 and requested that it be eliminated, stating that Appendix A goes beyond summarizing the existing records requirements and introduces several new recordkeeping requirements and retention times. Commenters also asserted that Appendix A should not be retroactive. Some commenters supported the inclusion of Appendix A, saying that it is a much-needed clarification of record requirements and retention. Noting that the title of Appendix A suggests that it is specific to gas transmission lines but that it does include some record retention intervals for distribution lines, NAPSR recommended that Appendix A be expanded to include records and retention intervals for all types of pipelines. Many commenters requested that PHMSA clarify that the proposed changes to Appendix A apply only to gas transmission lines.

Some commenters also opposed the newly proposed recordkeeping requirements for pipeline components at § 192.205. Commenters, including Dominion East Ohio, stated that PHMSA should exclude pipeline components less than 2 inches in diameter, as these small components are often purchased in bulk with pressure ratings and manufacturing specifications only printed on the component or box. They further stated that in doing this, PHMSA would be consistent with its proposed material properties verification requirements. Another commenter stated that these requirements should be eliminated because they are duplicative of the current requirements for establishing and documenting MAOP at § 192.619(a)(1).

Some commenters also opposed the proposed recordkeeping requirements regarding qualifications of welders and welding operators and qualifying persons to make joints in §§ 192.227 and 192.285, stating that keeping these records for the life of the pipeline is not needed, nor are they necessary for the establishment of MAOP.

Issues related to records were discussed during all of the GPAC meetings in various capacities. At the meeting in January 2017, several issues were discussed, including: broad records guidance in a general duties clause might be a good idea in theory but might cause unintended consequences, and they discussed the advisability of addressing necessary record components individually in the context of specific code sections.

The GPAC discussed the proposed addition of ''reliable'' to the phrase ''traceable, verifiable, and complete'' (TVC) record in the proposed rule. The ''TVC'' standard was recommended by the NTSB following the PG&E incident. Changing that standard could potentially derail work being done by operators to meet that traceable, verifiable, and complete record standard.

The GPAC also discussed PHMSA's statutory authority to impose the proposed recordkeeping requirements, even in subparts that are retroactive, because PHMSA is not requiring particular types of design, installation, construction, etc., but is requiring that operators keep records relevant to current operation.

At the GPAC meeting on June 6, 2017, the GPAC discussed the proposed recordkeeping requirements for the qualification of welders and welding operators as well as the qualification of persons making joints on plastic pipe systems. Specifically, the discussion revolved around whether the recordkeeping requirements should be for the life of the pipeline, as proposed in the NPRM, or whether it should be for 5 years. Certain members believed it should be a 5-year requirement to be consistent with other operator qualification requirements, and other members believed that a 5-year requirement would be adequate due to the ''bathtub curve'' phenomenon where pipelines are more likely to fail early or late in their service history. Therefore, having the records for welding qualification within that early period would be sufficient.

Following that discussion, the committee recommended that PHMSA modify the proposed rule to delete the word ''reliable'' from the records standard to now read ''traceable, verifiable, and complete'' wherever that standard is used; clarify that documentation be required to substantiate the current class location under § 192.5(d); and modify the recordkeeping provisions related to the

[74] *https://www.phmsa.dot.gov/regulations-fr/notices/2012-10866*; 77 FR 26822; May 7, 2012, ''Pipeline Safety: Verification of Records.''

qualification of welders and the qualification of persons joining plastic pipe to include an effective date and change the retention period of the necessary records to 5 years.

At the March 2, 2018, meeting, the GPAC recommended that PHMSA withdraw the general duty recordkeeping requirement at § 192.13(e) and Appendix A; modify the recordkeeping requirements for pipeline components to clarify they apply to components greater than 2 inches in nominal diameter; and revise the requirements related to material, pipe design, and pipeline component records to clarify the effective date of the requirements.

At the meeting on March 27, 2018, the GPAC recommended that PHMSA provide guidance in the preamble regarding what constitutes a traceable, verifiable, and complete record. Further, the GPAC recommended PHMSA clarify that the MAOP recordkeeping requirements in the MAOP establishment section at § 192.619(f) apply only to onshore, steel, gas transmission pipelines, and that they only apply to the records needed to demonstrate compliance with paragraphs (a) through (d) of the section. The GPAC suggested PHMSA could remove examples of acceptable MAOP documents from the rule and include that listing in the preamble of the final rule and through guidance materials.

The GPAC also recommended that PHMSA clarify that the MAOP recordkeeping requirements are not retroactive, that existing records on pipelines installed prior to the rule must be retained for the life of the pipeline, that pipelines constructed after the effective date of the rule must make and retain the appropriate records for the life of the pipeline, and that MAOP records would be required for any pipeline placed into service after the effective date of the rule. Further, the GPAC recommended PHMSA revise the rule by changing other sections, including §§ 192.624 and 192.917, to require when and for which pipeline segments missing MAOP records would need to be verified in accordance with the MAOP reconfirmation and material properties verification requirements of the rulemaking.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed records requirements. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to withdraw the proposed § 192.13(e) and Appendix A to avoid possible confusion regarding recordkeeping requirements. Also, whenever new recordkeeping requirements are included, PHMSA modified the rule to clarify that the new requirements are not retroactive. To the degree that operators already have such records, they must retain them. Operators must retain records created while performing future activities required by the code.

In addition to these general modifications, with regard to specific records requirements, PHMSA is modifying the rule as follows: (1) In § 192.5(d), operators must retain records documenting the current class location (but not historical class locations that no longer apply because PHMSA agrees they are not necessary). (2) In § 192.67, the rule is being modified to delete reference to ''original steel pipe manufacturing records'' to avoid retroactivity concerns, add wall thickness and seam type to clarify that this manufacturing information must be recorded, and include an effective date to eliminate retroactivity concerns. (3) In § 192.205, records for components are only required for components greater than 2 inches (instead of greater than or equal to 2 inches) (see Section III(A)(i)(3)). (4) In § 192.227, records demonstrating each individual welder qualification must be retained for a minimum of 5 years because PHMSA believes 5 years of welder qualification records are sufficient to evaluate whether systemic issues are present upon inspection and at the start-up of the pipeline. (5) In § 192.285, records demonstrating plastic pipe joining qualifications at the time of pipeline installation in accordance must be retained for a minimum of 5 years because PHMSA believes 5 years of records are sufficient to evaluate whether systemic issues are present upon inspection and at the start-up of the pipeline. (6) In § 192.619, PHMSA clarified that new recordkeeping for MAOP only apply to onshore, steel, gas transmission pipelines. In addition, PHMSA deleted the sentence with examples of records that establish the pipeline MAOP, which include, but are not limited to, design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data to prevent redundancies in the regulations as this list is maintained in § 192.607.

PHMSA notes that the recordkeeping requirements in this final rule under §§ 192.67, 192.127, 192.205, and 192.227(c) applicable to gas transmission pipelines will apply to offshore gathering pipelines and Type A gathering pipelines as well. In accordance with this final rule's requirements, operators of such pipelines must keep any of the pertinent records they have upon this rule's issuance, and they must retain any records made when complying with these requirements following the publication of this rule. PHMSA notes that the requirements for creating records in §§ 192.67, 192.127, 192.205, and 192.227(c) are forward-looking requirements. However, and in accordance with this final rule, operators must retain any records they currently have for their pipelines. Any records generated through the course of operation, including, most notably, records generated by the material properties verification process at § 192.607, must also be retained by operators for the life of the pipeline.

As requested by the GPAC, PHMSA considered moving § 192.619(e) to be a subsection of § 192.619(a) and considered referencing § 192.624 in § 192.619(a). However, PHMSA is retaining the proposed paragraph (e) in the final rule and the reference to § 192.624 within § 192.619(e) because it more clearly requires pipeline segments that meet any of the applicability criteria in § 192.624(a) must reconfirm MAOP in accordance with § 192.624, even if they comply with § 192.619(a) through (d). This also avoids the potential for conflict if this requirement were to be placed in a paragraph that applies to gathering lines and distribution lines. It also makes it clear that pipeline segments with MAOP reconfirmed under § 192.624 are not required to comply with § 192.619(a) through (d).

Lastly, throughout this final rule, PHMSA is deleting the word ''reliable'' from the records standard to now read ''traceable, verifiable, and complete'' wherever that description is used. PHMSA issued advisory bulletins ADB 12–06 on May 7, 2012 (77 FR 26822) and ADB 11–01 on January 10, 2011 (76 FR 1504). In these advisory bulletins, PHMSA provided clarification and guidance that all documents are not records and provided additional information on the definition and standard for records. For a document to be a record, it must be traceable, verifiable, and complete. PHMSA provides further explanation of these concepts below.

Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, which include mechanical and chemical properties; purchase requisition; or as-built documentation indicating minimum pipe yield

strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.

Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a pipeline segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipeline segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by a qualified individual who observed the test or inspection being performed.

Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking such as a corporate stamp or seal. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipeline segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.

For example, a mill test report must be traceable, verifiable, and complete, which is a typical record for pipelines. For the mill test report to be traceable it would need to be dated in the same time frame as construction or have some other link relating the mill record to the material installed in the pipeline, such as a work order or project identification. For the mill test report to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the mill test report to be complete, it must be signed, stamped, or otherwise authenticated as a genuine and true record of the material by the source of the record or information, in this example it could be the pipe mill, supplier, or testing lab.

Another common record is a pressure test record, which must be traceable, verifiable, and complete. For the pressure test record to be traceable, it would need to identify a specific and unique segment of pipe that was tested (such as mileposts, survey stations, etc.) or have some other link relating the pressure test to the physical location of the test segment, such as a work order, project identification, or alignment sheet. For the pressure test record to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the pressure test record to be complete, it should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, elevation information, and any other information required by § 192.517, as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test.

I. Miscellaneous Issues

iii.—Cost/Benefit Analysis, Information Collection, and Environmental Impact Issues

NPRM Assumptions/Proposals

U.S. Code, title 49, chapter 601, section 60102 specifies that the U.S. Department of Transportation (U.S. DOT), when prescribing any pipeline safety standard, shall consider relevant available gas and hazardous liquid pipeline safety information, environmental information, the appropriateness of the standard, and the reasonableness of the standard. In addition, the U.S. DOT must, based on a risk assessment, evaluate the reasonably identifiable or estimated benefits and costs expected to result from implementation or compliance with the standard. PHMSA prepared a preliminary regulatory impact analysis (PRIA) to fulfill this statutory requirement for the proposed rule and a new regulatory impact analysis (RIA) for this final rule. In addition, PHMSA's Environmental Assessment (EA) is prepared in accordance with NEPA, as amended, and the Council on Environmental Quality (CEQ) regulations for implementing NEPA (40 CFR parts 1500–1508). When an agency anticipates that a proposed action will not have significant environmental effects, the CEQ regulations provide for the preparation of an EA to determine whether to prepare an environmental impact statement or finding of no significant impact.

Summary of Public Comment

Cost Impacts

Several commenters provided input on the cost analysis conducted in the PRIA, providing comments on the structure, assumptions, and unit costs in the PRIA as well as on the lack of accounting for impacts such as the abandonment of pipelines and the cost increase to electricity ratepayers.

Some public interest groups provided input on the cost analysis in the PRIA. EDF stated that the PRIA reasonably addressed uncertainty and lack of information surrounding certain key data assumptions. EDF further stated that the PRIA aligned with Office of Management and Budget guidance on the development of regulatory analysis for rulemakings. They stated that PHMSA used conservative values when making best professional judgments. PST asserted that the costs included in the PRIA for reconfirmation of MAOP, data gathering, record maintenance, and data integration for lines subject to the IM provisions result from the current IM regulations and practices and should not be attributed to this rulemaking. They further stated that the PRIA should be amended to remove these costs related to lines within HCAs.

Several trade associations and industry pipeline entities provided input on the assumptions, methodology, and unit costs used in the PRIA, stating that PHMSA underestimated the cost of complying with the proposed regulations. AGA stated that the organization of the PRIA by ''topic areas'' made it difficult to evaluate the cost estimates of the various provisions of the rule and requested that PHMSA provide a RIA with the final rule that addresses each regulatory section as organized in the preamble. Many commenters, including INGAA, AGA, AGL Resources, and Piedmont, stated that the PRIA underestimated the cost impacts of increased material properties verification, recordkeeping, and MAOP reconfirmation requirements. AGL Resources asserted that complying with the proposed record requirements would involve increased labor and investment costs that should be quantified in the final RIA. AGA stated that it was unclear whether or how the PRIA incorporated material properties verification costs related to material documentation, plan creation, revisions, and testing. NYSEG asserted that the PRIA underestimated the cost impact of the proposed rule on smaller local

distribution companies with combined transmission and distribution systems and estimated that they would have to perform IM elements on 8 times the mileage currently in their IM program. Lastly, INGAA provided a higher cost for MAOP confirmation than was estimated in the PRIA due in large part to their assumption that industry would continue to rely on pressure testing, as they asserted that the proposed methods for ILI and ECA are not feasible.

INGAA, AGA, and API submitted detailed cost analyses to the rulemaking docket, while many other commenters (approximately 40) provided estimated unit costs for various provisions of the proposed rule that were generally higher than the unit costs used in the PRIA. For example, Southwest Gas stated that the costs included in the PRIA for options such as ILI and pressure testing were not representative of the costs to their system. With regard to the cost of integrity assessments, BG&E stated that it would cost them over $1 million per year to perform integrity assessments on the additional 100 miles of MCA transmission pipelines, a total which equates to a higher cost per mile estimate than was used in the PRIA. Additionally, New Mexico Gas Co. stated that the proposed rule would cost their company $5.6 million per year to perform integrity assessments on 528 miles of MCA transmission pipe. Vectren estimated the impact to its transmission system would cost $22 million annually. Lastly, PG&E stated that their forecasted costs to implement the proposed rule are significantly higher than the estimates in the PRIA. PG&E provided a comparison of the PRIA costs with their expected expenditures to comply with many provisions in the proposed rule. They projected the cost of compliance would require an upfront investment of $578 million in addition to $222 million per year (as well as a reoccurring cost of $30 million every 7 years) and stated that, comparatively, the PRIA estimates a present value annualized cost of $47 million per year.

Some stakeholders provided input on the estimated number of miles that PHMSA used to determine the regulatory impact of the provisions in the proposed rule. For example, INGAA stated that it assumed the mileage estimated by PHMSA for estimation of MAOP confirmation, material properties verification, and integrity assessments outside HCAs to be accurate with the addition of reportable in-service incidents since last pressure test data. INGAA also asserted that the mileage estimated for MCA transmission pipes should be done on the per-foot basis instead of on the per-mile basis because these pipes are likely to be an aggregation of short pipeline segments that are 1 mile or shorter in length. The North Dakota Petroleum Council asserted that proposed changes in the definition of onshore gathering lines would dramatically increase the number of miles of regulated gathering wells beyond the mileage estimates in the PRIA.

Some commenters asserted that the financial impact of the proposed rule would be immense and that, because operators would not be able to bear these costs alone, they would likely pass the costs on to the ratepayers. For example, APGA stated that all of their member utilities purchase gas and pay transportation charges to transmission pipelines to deliver gas from the producer to the utility. They asserted that ratepayers would pay for the costs that would be incurred by their transmission suppliers to comply with this rule. Similarly, Indiana Utility Regulatory Commission requested that PHMSA consider the costs to ratepayers in its cost analysis. Other commenters stated that this rule could force operators to take significant portions of their pipelines out of service while they are brought into compliance and that the PRIA failed to recognize that FERC requires interstate natural gas pipelines operators to provide demand charge credits to customers when service is disrupted.

Some commenters stated that the proposed rule may cause pipeline abandonment and that these impacts should be considered in the final RIA. Boardwalk Pipeline stated that if a pipe is no longer economic to operate, but FERC does not grant abandonment authority, a pipeline company would be forced to either operate a pipeline that may not meet PHMSA standards or undertake expensive replacement projects. Boardwalk Pipeline further stated that while operators may seek to recover the costs of replacement projects through rate increases, in a competitive pipeline market where operators are forced to discount their pipeline rates in order to retain customers, these costs might be too great to recover. Similarly, the Independent Petroleum Association of America stated that the PRIA failed to account for the costs that could be incurred by operators if pipeline infrastructure is abandoned because the cost that would be required to comply with the rule would necessitate this abandonment. The Public Service Commission of West Virginia suggested that, should operators abandon wells and pipelines due to the requirements of this proposed rule, it could cause an environmental and economic liability for State regulators if operators abandon wells and pipelines without proper clean up.

Several commenters expressed concern that PHMSA's cost-benefit analysis does not meet the requirements established by the 2011 Pipeline Safety Act and the Administrative Procedures Act (APA). Trade associations stated that the PRIA does not fulfill PHMSA's statutory obligations because it omits relevant costs, relies on incorrect assumptions, and contains multiple inconsistencies. INGAA asserted that the PRIA does not comply with the APA because the finding in the PRIA that the proposed benefits outweigh the costs is contingent on an underestimation of the costs of the proposed rule. INGAA also noted that flawed cost-benefit analysis can be grounds for courts to reject agency rulemakings. INGAA asserted that the proposed rulemaking does not comply with the Paperwork Reduction Act (PRA), because PHMSA's estimate of the information collection burden did not include the costs of these additional recordkeeping requirements for transmission pipeline operators.

Benefit Estimates

PHMSA also received comments on the benefits associated with the proposed rule. Physicians for Social Responsibility expressed their support of the proposed rule and the analysis of reduced accidents and increased worker safety in the PRIA. Additionally, Physicians for Social Responsibility stated that many harmful air pollutants, such as nitrous oxide, sulfur dioxide, particulate matter, formaldehyde, and lead, are all associated with gas pipelines and compressor stations. They further stated that this rule would help reduce or mitigate this pollution and that these public health benefits should be accounted for in the benefits calculations.

Other commenters, including AGA and INGAA, stated that PHMSA overestimated the damage caused by incidents in the quantification of benefits in the PRIA. AGA stated that PHMSA allowed one major incident to skew the data in their benefits analysis and proposed that PHMSA adopt a new approach to quantify the benefits of reduced accidents. INGAA stated that using data from the past 13 years skewed the results and that the most recent 5 years of incident history would more reasonably reflect positive developments in pipeline safety, given that significant developments in pipeline safety have occurred within this time period.

Several commenters provided input on the proposed use of the social cost of carbon and the social cost of methane in the PRIA. EDF and National Resource Defense Council supported the use of the social costs of carbon and methane methodology in the PRIA. However, these commenters stated that the estimates for social costs of carbon and methane were likely too conservative and that the values should be higher than those used in the PRIA. These commenters stated that PHMSA should encourage the Interagency Working Group on Social Cost of Carbon to update regularly the social cost of carbon and social cost of methane as new economic and scientific information emerges. API stated that the proposed use of the social cost of methane to calculate the benefits of emissions reductions was flawed due to the discount rates used by PHMSA. They asserted that PHMSA used low discount rates that led to a liberal damage estimate. In addition, API and Industrial Energy Consumers of America asserted that the social cost of carbon values used by PHMSA inappropriately impose global carbon costs on domestic manufacturers, which damages the industry's ability to compete internationally. AGA stated that the process used to develop the social cost of methane values in the PRIA did not undergo sufficient expert and peer review. INGAA stated that PHMSA overestimated the amount of greenhouse gas emissions that the rule would reduce.

Environmental Impacts

Several commenters noted that the 2011 Pipeline Safety Act mandates that PHMSA consider the environmental impacts of proposed safety standards. Citizen groups stated that the proposed regulation fulfills this statutory obligation and is a step forward in reducing methane emissions from natural gas pipelines. Multiple citizen groups emphasized the consequences of climate change, the high global warming potential of methane, and the responsibility of natural gas systems for a significant portion of U.S. methane emissions. Citizen groups underlined the importance of regulating methane leaks and considering methane's climate implications in natural gas regulations. The Lebanon Pipeline Awareness Group addressed local environmental impacts, requesting that pipelines not be permitted to contaminate agricultural soils.

Trade associations asserted that PHMSA did not fulfill its statutory obligation to consider the full environmental impacts of the proposed safety standards, suggesting that PHMSA failed to consider several topics in the NPRM that would have direct environmental impacts. These commenters claimed that certain topics and their impacts, including IM clarifications, MAOP reconfirmation, and hydrostatic pressure testing, were mischaracterized in the EA, and that PHMSA further underestimated the number of excavations that would need to be made per the proposal as well as the impacts of procuring and disposing of water for hydrostatic tests.

Trade associations further expressed concerns that, while PHMSA had addressed the emissions avoided under the proposed rule, PHMSA had not addressed the extent to which the proposed rule would increase emissions. AGA and INGAA noted that operators need to purge lines of natural gas before conducting hydrostatic tests or removing pipelines from service for replacement or repair. These commenters stated that the proposed regulation would increase methane emissions by increasing the number of hydrostatic tests, pipeline replacements, and pipeline repairs required and asserted that the EA did not take the increased emissions from these blowdowns into account. INGAA asserted that not considering these methane emissions constituted a violation of the 2011 Pipeline Safety Act and failure to ''engage in reasoned decision making.'' INGAA also suggested that the methane emissions resulting from this rulemaking would run counter to President Obama's goals of reducing methane emissions.

EDF and PST commissioned a study from M.J. Bradley & Associates (MJB&A) that calculated the extent to which the proposed rule would result in blowdown emissions. MJB&A found that potential methane emissions resultant from the proposed rule would increase annual methane emissions from natural gas transmission systems by less than 0.1 percent and increase annual methane emissions from transmission system routine maintenance by less than one percent. MJB&A also noted five mitigation methods that if implemented, could decrease blowdown emissions by 50 to 90 percent.[75] MBJ&A calculated that the societal benefits of methane reduction outweighed the mitigation costs for all mitigation options considered. Based on this study, EDF asserted that while the marginal increase in emissions from the proposed rule would be small, the total emissions from blowdowns would nonetheless be significant. They stated that PHMSA should require operators to select and implement one of the mitigation options and report to PHMSA information about their blowdown events, such as the mitigation option selected and the amount of product lost due to blowdowns required by the proposed rule. EDF also stated that if operators do not mitigate blowdown emissions, they should be required to provide an engineering or economic analysis demonstrating why mitigation is deemed infeasible or unsafe.

AGA stated that the EA did not address other environmental impacts resultant from hydrostatic pressure testing. AGA noted two anticipated water-related impacts: (1) Hydrostatic pressure testing's water demand could aggravate water scarcity in already water-scarce environments, and (2), the water used in hydrostatic tests could introduce contaminants if disposed on-site (or be very expensive to transport to off-site disposal). AGA explained that wastewater from hydrostatic tests could include hydrocarbon liquids and solids, chlorine, and metals.

AGA also asserted that the EA did not adequately consider the land disturbances that could result from the proposed hydrostatic testing requirements, nor did it consider that performing inline inspections and modifying pipelines to accommodate inline inspection tools would generate waste and disturb natural lands. AGA explained that operators must clean pipelines prior to conducting inline inspections or modifying pipelines for inline inspection tools and that this cleaning could produce large volumes of pipeline liquids, mill scale, oil, and other debris. AGA expressed concerns that the proposed EA did not discuss these environmental impacts associated with requiring MAOP confirmation, given that PHMSA anticipates that most affected pipelines would verify MAOP using ILI and pressure testing.

AGA also provided input on the local environmental impacts of the proposed increased testing and inspection. AGA expressed concerns that the EA had (1), underestimated the quantity of excavations that would be required under the proposed rule, and (2), inadequately assessed the environmental impacts of those excavations. AGA asserted that the EA had insufficiently considered the extent to which more excavations would generate water and soil waste. AGA also suggested that the proposed rule may

[75] The methods are (1) gas flaring; (2) pressure reduction prior to blowdown with inline compressors; (3) pressure reduction prior to blowdown with mobile compressors; (4) transfer of gas to a low-pressure system; and (5) reducing the length of pipe requiring blowdown by using stopples.

induce operators to modify or replace pipelines and that these modifications and replacements may affect land beyond existing rights of way. AGA asserted that this additional land area should be considered in the EA.

Trade associations raised other technical issues regarding the EA. AGA expressed concerns that PHMSA provided insufficient information about methods used to calculate values in the EA and that this insufficient documentation interfered with stakeholders' ability to provide comments on the values that PHMSA chose. INGAA asserted that the proposed rule fell short of several legal obligations under NEPA, stating that the EA does not provide the required ''hard look'' at environmental impacts, that the EA does not adequately discuss the indirect and cumulative effects of the proposed rule, and that the purpose and need statement in the EA do not fulfill NEPA instructions. INGAA also expressed concern that PHMSA did not consider sufficient regulatory alternatives, stating that the EA considered solely the proposed rule, one regulatory alternative, and the no action alternative. INGAA stated that given the many provisions of the proposed rule, this approach was too limited.

Other Impacts

Some trade associations and pipeline industry entities provided input that the PRIA failed to account for the indirect effects of operators shifting resources to comply with the proposed rule. For example, AGA stated that the PRIA did not consider the potential indirect impacts the rule might impose on distribution lines. They asserted that the magnitude and prescriptiveness of the proposed rule would require distribution companies with intrastate transmission and distribution assets to reassign their limited resources to transmission lines.

Some commenters stated that PHMSA did not consider that the proposed rule would divert resources away from voluntary safety programs their companies are initiating, stating that these voluntary safety measures would be scaled back because of the proposed rule. For example, AGA stated that accelerated pipe replacement programs that replace aging cast iron, unprotected steel pipe, and vintage plastic pipe, would lose resources as operators shift staff and capital to comply with the proposed rule. They further asserted that failing to replace these pipes would delay reductions in methane emissions from old, leaky pipes.

PHMSA Response

Cost Impacts

PHMSA has reviewed the comments related to the RIA for the proposed rule and has revised the final analysis consistent with the final rule and in consideration of the comments. PHMSA addressed the comments received on the RIA in two key ways. First, PHMSA revised many of the requirements in the final rule, including (a) revising or clarifying that the final provisions do not apply to gas distribution or gas gathering pipelines; (b) revising MAOP reconfirmation requirements for grandfathered pipelines to include only those lines with MAOP greater than or equal to 30 percent SMYS; (c) streamlining the process for operators to use an alternative technology for MAOP reconfirmation; (d) removing the term ''occupied sites'' in the MCA definition; and (e) revising the records provisions to remove certain proposed provisions and clarifying that the new requirements are not retroactive. These changes, as well as others made in the final rule, result in less costly and more cost-effective requirements. Second, in response to comments received, PHMSA made several revisions to the analysis conducted in the RIA for the proposed rule, discussed below. Also, in response to comments, PHMSA revised the final RIA to align more closely to the preamble organization.

PHMSA acknowledges the baseline issues associated with establishing MAOP, data collection, and other provisions noted in the comments. In the final RIA, PHMSA is including estimated incremental costs to reconfirm MAOP for lines within HCAs based on a current compliance baseline. Attributing compliance to existing pipeline safety regulations would reduce both the costs and benefits of the final rule. Regarding the comments that the RIA for the proposed rule underestimated the cost impacts of material properties verification, recordkeeping, and MAOP confirmation, as discussed above, the changes to the scope and applicability of the MAOP reconfirmation, data, and recordkeeping provisions result in common-sense, cost-effective requirements. For example, PHSMA designed the final requirements for material properties verification to allow operators the option of a sampling program that opportunistically takes advantage of repairs and replacement projects to verify material properties simultaneously. The final provisions allow, over time, operators to collect enough information to gain significant confidence in the material properties of pipe subject to this requirement.

Further, as discussed under the section regarding the material properties verification process, the final rule removes the applicability criteria of the material properties verification requirements and makes a procedure for obtaining pipeline physical properties and attributes that are not documented in traceable, verifiable, and complete records or for otherwise verifying pipeline attributes when required by MAOP reconfirmation requirements, IM requirements, repair requirements, or other code sections. Therefore, due to the changes made from the proposed rule, the material properties verification requirements mandated by section 23 of the 2011 Pipeline Safety Act represent a cost savings in comparison to existing regulations, although PHMSA has not quantified those savings.

With regard to the operator-provided cost information or estimates of the proposed rule, the commenters' estimates were not transparent enough for PHMSA to discern the assumptions and inputs underlying the estimates. As a result, PHMSA could not reliably confirm whether the cost information accurately reflected the quantity and character of the actions required by the proposed rule. To improve the transparency of the analysis and address commenters' concerns about PHMSA's reliance on best professional judgment in the RIA for the proposed rule, PHMSA contacted five vendors of pipeline inspection and testing services to obtain updated cost estimates for several unit costs that were based on best professional judgement in the RIA for the proposed rule. These vendors provided representative incremental costs associated with the final rule requirements. In the final RIA, PHMSA used prices provided by vendors to estimate unit costs for all MAOP reconfirmation and integrity assessment methods, as well as for upgrades to launchers and receivers.

Regarding MAOP reconfirmation specifically, in the RIA for the proposed rule PHMSA assumed operators would conduct MAOP reconfirmation using either pressure testing or ILI. In the final RIA, based on feedback received during a GPAC meeting,[76] PHMSA assumed that operators would reconfirm MAOP using a mix of all six available compliance methods.

Additionally, in the final RIA, PHMSA analyzed the requirements for MAOP reconfirmation and integrity

[76] GPAC Meeting, March 26–28, 2018. For a transcript of the meeting, see *https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=970.*

assessments outside HCAs for each operator individually based on the information they submitted in their Annual Reports. Based on the information in operator Annual Reports and the final rule requirements for MAOP reconfirmation, some operators will incur less of an impact than indicated by their public comments.

Regarding the comment that the proposed changes to the definition of onshore gathering lines would dramatically increase the number of miles of regulated gathering wells beyond the mileage estimates in the RIA for the proposed rule, this final rule does not change the definition of gathering pipelines.

With respect to pipelines located within MCAs, PHMSA confirmed the analysis of the length of gas transmission pipelines located within MCAs in the RIA for the proposed rule by integrating additional spatial data from the U.S. Census Bureau, U.S. Geological Survey, Environmental Systems Research Institute, and Tele-Atlas North America, Inc. For additional details on the MCA GIS analysis, see section 5.7 of the RIA for the final rule. This allowed PHMSA to confirm the number of impacted miles. Additionally, due to existing state MAOP reconfirmation requirements, PHMSA updated the RIA to reflect that impacts in California are not attributable to the rule. Lastly, PHMSA presented all impacted mileage on a dollar-per-foot basis instead of dollars per mile, based on comments received that these pipeline segments are likely to be an aggregation of short pipeline segments that are a mile or shorter in length.

Regarding the comment that PHMSA underestimated the cost impact of the proposed rule on smaller local distribution companies with combined gas transmission and gas distribution systems, PHMSA conducted an analysis of the rule's impact on small entities by comparing entity-level cost estimates to annual entity revenues and identifying entities for which annualized costs may exceed 1 percent and 3 percent of revenue. As documented in the final Regulatory Flexibility Act (FRFA) analysis, PHMSA relied on conservative assumptions in performing this sales test, which may overstate, rather than understate, compliance costs for small entities. PHMSA found that the final rule will not have a significant economic impact on small entities.

PHMSA does not agree that the final rule requirements constitute a significant energy action. PHMSA agrees with the comment that the costs would be passed on to ratepayers; however, PHMSA disagrees that these costs would be immense. E.O. 13211 requires agencies to prepare a Statement of Energy Effects when undertaking certain agency actions if, among other criteria, the regulation is expected to see an increase in the cost of energy production or distribution in excess of one percent. The annualized cost of these requirements represents less than 0.1 percent of pipeline transportation of natural gas (North American Industry Classification System code 486210) industry revenues ($25 billion), adjusting the 2012 Economic Census value into 2017 dollars using the Gross Domestic Product Implicit Price Deflator Index. Therefore, in the aggregate it is extremely unlikely that these requirements would cause a significant increase in costs that utilities would pass on to the ratepayer.

Available information supports that, in the baseline, operators are replacing or abandoning certain pipelines regardless of the implementation of this rule as well as taking other actions such as making lines piggable.[77] As discussed above, in the final RIA, PHMSA assumed some use of pipe replacement and abandonment as a means of operators reconfirming MAOP. However, the costs of replacing infrastructure operating beyond the design useful life are not attributable to safety regulations and investment in plant, including a return on investment, are already recovered through rates.

The RIA for the final rule meets all PHMSA's requirements under applicable acts and executive orders. The analysis involves estimating a baseline scenario and changes under the regulation. PHMSA has used its judgement, available data, information, and analytical methods to develop an analysis of the baseline and incremental costs and benefits under the rule. As discussed above, some costs and benefits may be attributable to existing requirements and some may occur in the absence of the rule.

Benefits Estimates

PHMSA agrees that recent data is more reflective of recent improvements in pipeline safety and performance relative to current standards. For the final RIA, PHMSA used more recent data on pipeline incidents from 2010 to 2017 versus the 2003 to 2015 data used in the RIA for the proposed rule. PHMSA used the data from 2010 on because PHMSA updated its incident reporting methodology in 2010, and this period therefore provides the largest available sample of consistently reported incident data. Regarding the benefits analysis for the preliminary RIA developed for the NPRM potentially being skewed by one major incident (the PG&E incident at San Bruno), there is no evidence that more serious incidents are not possible in the future in the absence of the regulation, and therefore, PHMSA does not exclude this incident when qualitatively assessing benefits. At the same time, and although PHMSA developed this rule to prevent future, similar incidents, PHMSA cannot know with certainty whether a similar incident would occur again absent this rulemaking. According to the historical record, serious incidents, like the one occurring at San Bruno, occur approximately once per decade. For example, on August 19, 2000, a 30-inch-diameter natural gas transmission pipeline operated by the El Paso Natural Gas Company ruptured adjacent to the Pecos River near Carlsbad, NM. The released gas ignited and burned for 55 minutes. Twelve persons camping near the incident location were killed, and their three vehicles were destroyed.[78] Similarly, on March 23, 1994, a 36-inch-diameter natural gas transmission pipeline owned and operated by Texas Eastern Transmission Corporation ruptured in Ellison Township, NJ. The incident caused at least $25 million in damages, dozens of injuries, and the evacuation of hundreds.[79] More detailed data on current pipeline integrity in relation to populations and the environment would enable more detailed predictions of the benefits of regulations.

Due to the speculative nature of predicting the occurrence, avoidance, and character of specific future pipeline incidents, in the final RIA, PHMSA elected not to quantify the rule's benefits. PHMSA uses this approach rather than make highly uncertain predictions about both a specific number of future incidents avoided due to the final rule, and the character of avoided incidents with respect to effects on benefit-analysis endpoints (*e.g.,* fatalities, injuries, evacuation). The

[77] PG&E. 2011. ''Pacific Gas And Electric Company's Natural Gas Transmission Pipeline Replacement Or Testing Implementation Plan.'' California Public Utilities Commission; Consolidated Edison Company Of New York. 2016. ''Consolidated Edison Company Of New York, Inc. 2017–2019 Gas Operations Capital Programs/Projects.'' New York State Department of Public Service. *http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-G-0061&submit=Search.*

[78] Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico, August 19, 2000, Pipeline Accident Report, NTSB/PAR–03/01, Washington, DC.

[79] Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Pipeline Accident Report, NTSB/PAR–95–01, Washington, DC.

quantified benefits for each provision therefore represent the quantity of a given benefit category required to achieve a dollar value equal to the provision's compliance cost.

PHMSA does not have data on harmful air pollutants such as nitrous oxide, sulfur dioxide, particulate matter, formaldehyde, and lead associated with gas pipelines and compressor stations, or the reductions in these pollutants under the rule. Therefore, the analysis did not address the environmental costs associated with these pollutants. PHMSA did not include estimates of benefits based on the social cost of methane for the final rule.

Environmental Impacts

Regarding the comments stating that the preliminary EA did not adequately consider the air emissions that would result from hydrostatic pressure testing, inline inspections, excavations, and MAOP reconfirmation, PHMSA revised the EA to address this issue. Commenters asserted that by increasing the number of hydrostatic tests, pipeline replacements, and pipeline repairs required, the proposed provisions would increase methane ''blowdown'' emissions that result from the required purging of natural gas pipelines before conducting these actions. PHMSA revised the EA to include a discussion of the study conducted by M.J. Bradley & Associates (MJB&A) [80] that calculated the extent to which the proposed rule would result in blowdown emissions.

MJB&A found that unmitigated blowdown from the miles of transmission pipeline that would be required to conduct a MAOP determination would release an average of 1,353 metric tons per year of methane to the atmosphere for the 15-year compliance period [81] proposed by PHMSA. By comparison, historical unintentional releases from natural gas transmission pipelines outside of HCAs with piggable lines greater than 30 percent SMYS (a universe of facilities that could be subject to MAOP reconfirmation in MCAs) averaged 13,500 metric tons per year from 2010 to 2017. These releases were caused by 163 incidents that released an average of 663.4 metric tons per incident.[82]

Therefore, if the final rule requirements avoided two average incidents per year, the rule would not result in any net methane releases. MJB&A further stated that the potential methane emissions resultant from the NPRM would increase annual methane emissions from natural gas transmission systems by less than 0.1 percent and increase annual methane emissions from transmission system routine maintenance/upsets by less than one percent. Given these factors, PHMSA does not believe that the final rule will result in a significant, if any, increase in methane releases.

In response to comments, PHMSA revised the EA to also include a discussion of water-related impacts resulting from hydrostatic pressure testing as well as waste generation land disturbances from hydrostatic pressure testing and inline inspections. Operators must conduct all waste and wastewater disposal activities in accordance with federal, state, and local regulations and permit requirements, and the final rule requires processes and procedures in which pipeline operators are already familiar with respect to pipeline IM. Regarding the comments on the environmental impacts of pipe replacement, as discussed above, the impacts of replacing infrastructure that is operating beyond the design useful life are not attributable to the final rule requirements. While the final RIA assumes that operators will comply with MAOP reconfirmation using pipe replacement for approximately 300 miles of pipe, PHMSA did not consider these replacements to be incremental costs. Similarly, the environmental impacts are not attributable to the final rule requirements.

Other Impacts

PHMSA disagrees with the analysis of operators shifting resources away from safety programs to comply with the proposed rule. PHMSA has revised and clarified the pipeline safety and integrity applicability of the final rule such that many operators will incur lower costs than previously anticipated. The final rule also provides long compliance schedules to enable planning for efficient compliance actions.

IV. GPAC Recommendations

This section briefly summarizes the NPRM proposals, the GPAC's major comments on the proposals discussed, and the recommendations of the committee regarding how those provisions should be finalized. More detail, the presentations, and the transcripts from all of the meetings are available in the docket for this rulemaking.[83] The provisions, which are presented in the order they were discussed at the GPAC meetings, the changes the committee agreed upon, and the corresponding vote counts are as follows:

6-Month Grace Period for 7-Calendar-Year Reassessment Intervals (§ 192.939(b))

In the NPRM, PHMSA proposed to allow operators to request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to the Secretary with sufficient justification of the need for the extension in accordance with the technical correction at section 5 of the 2011 Pipeline Safety Act. The committee had no objections or substantial comments on this provision and voted 12–0 that it was, as published, technically feasible, reasonable, cost-effective, and practicable.

Safety Features on ILI Launchers and Receivers (§ 192.750)

In the NPRM, PHMSA proposed to require operators equip ILI tool launchers and receivers with a device capable of safely relieving pressure in the barrel before the insertion or removal of ILI tools, scrapers, or spheres. Further, PHMSA proposed requiring operators to use a suitable device to indicate that pressure has been relieved in the barrel or otherwise provide a means to prevent the opening of the barrel if pressure has not been relieved. The committee voted 12–0 that this provision was, as published, technically feasible, reasonable, cost-effective, and practicable, as long as PHMSA clarified that the rule language does not require ''relief valves'' or use ''relief valve'' as a term. Some committee members were concerned that using language related to ''relief valves'' would bring in other code requirements, which was not PHMSA's intent.

Seismicity (§§ 192.917, 192.935(b)(2))

In the NPRM, PHMSA proposed to include seismicity in the list of factors operators must evaluate for the threat of outside force damage when considering preventative and mitigative measures, as well as include the seismicity of an area as a pipeline attribute in an operator's data gathering and integration when performing risk analyses. The committee had no substantial comments or recommendations on this topic, and

[80] The study was commissioned by EDF and PST and is available at *http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf.*

[81] See § 192.624(b).

[82] ''Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data.'' Phmsa.Dot.Gov. 2017. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.*

[83] *https://www.regulations.gov/docket?D=PHMSA-2011-0023.*

they voted 12–0 that this provision was, as published, technically feasible, reasonable, cost-effective, and practicable.

Records (§§ 192.5(d), 192.13(e), 192.67, 192.127, 192.205, 192.227(c), 192.285(e), 192.619(f), 192.624(f), Appendix A)

In the NPRM, PHMSA proposed to clarify that the records required by part 192 must be documented in a reliable, traceable, verifiable, and complete manner. PHMSA summarized the recordkeeping requirements of part 192 in a new Appendix A, and required that operators must re-establish pipeline documentation whenever records were not available and make and retain records demonstrating compliance with part 192. Issues related to records were discussed through the final 4 GPAC meetings over the course of 2017 and 2018. The committee found the assorted provisions related to records as being technically feasible, reasonable, cost-effective, and practicable, if certain changes were made. Specifically, the committee recommended the word ''reliable'' be deleted from the records standard so that it reads ''traceable, verifiable, and complete'' records wherever the standard is used. Members noted that the NTSB never used the term ''reliable,'' and a PHMSA advisory bulletin reflects the language without referring to ''reliable'' records. In the class location requirements at § 192.5, the committee recommended PHMSA clarify that documentation be required to substantiate the current class location and not previous historical ones. The committee also recommended that PHMSA modify the requirements for the qualification of welders and persons joining plastic pipe to include an effective date and change the records retention provision to a period of 5 years.

During the June 2017 GPAC meeting, the committee recommended PHMSA amend provisions related to the general duty clause for records and edit the corresponding reference to retention periods in Appendix A. After further discussion, during the meeting on March 2, 2018, the committee recommended PHMSA withdraw the proposed addition of § 192.13. Similarly, in the June 2017 meeting, the committee recommended PHMSA modify the proposed Appendix A to clarify that it does not apply to distribution or gathering pipelines. After considering the issue at the meeting on March 2, 2018, the committee recommended PHMSA withdraw proposed Appendix A from the rulemaking.

Other changes the committee suggested regarding the proposed recordkeeping requirements included revising the record provisions for materials, pipe design, and components to clarify the effective date of those provisions and recommended PHMSA clarify that the recordkeeping provisions for components only applies to components greater than 2 inches in nominal diameter. The recordkeeping provisions proposed under the MAOP determination and MAOP reconfirmation sections were discussed by the GPAC separately and are expanded upon under the discussions for those specific topics below.

Following those discussions over the course of multiple meetings, the committee voted unanimously that the provisions related to recordkeeping requirements in part 192 were technically feasible, reasonable, cost-effective, and practicable, if PHMSA made the changes outlined above.

IM Clarifications (§§ 192.917(e)(2), (e)(3) & (e)(4))

In the NPRM, PHMSA proposed several changes to provisions related to how operators use data in their IM programs and manage certain types of defects. PHMSA proposed changes regarding an operator's analysis of cyclic fatigue and clarifying that certain pipe, such as low-frequency electric resistance welded pipe, must have been pressure tested for an operator to assume that any seam flaws are stable. PHMSA also proposed that any failures or changes to operation that could affect seam stability must be evaluated using a fracture mechanics analysis.

Regarding cyclic fatigue, some GPAC members expressed concern that PHMSA proposed to require an annual analysis of cyclic fatigue even if the underpinning conditions affecting cyclic fatigue had not changed. Certain GPAC members wanted to ensure that it would be a change in conditions that would trigger an evaluation and that operators would not necessarily need to do an evaluation within a certain period otherwise. During the meeting, PHMSA suggested it would consider changing cyclic fatigue analysis from annually to periodically based on any changes to cyclic fatigue data and other changes to loading conditions since the previous analysis was completed, not to exceed 7 calendar years. Further, PHMSA would consider whether there was conflict with this section and the MAOP reconfirmation requirements, which was a concern brought up during the public comment period of the meeting. Following the discussion, the committee voted 11–0, that the provisions related to cyclic fatigue were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the paragraph based on the GPAC member discussion and PHMSA's proposed language at the meeting.

For the provisions related to the stability of manufacturing- and construction-related defects, PHMSA proposed during the GPAC meeting to provide that an operator could consider manufacturing- and construction-related defects as stable only if the covered segment has been subjected to a subpart J pressure test of at least 1.25 times MAOP and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test. Pipeline segments that have experienced a reportable incident since its most recent subpart J pressure test due to an original manufacturing-related defect, a construction-related defect, an installation-related defect, or a fabrication-related defect would be required to be prioritized as a high-risk segment for the purposes of a baseline assessment or a reassessment. PHMSA proposed to explicitly lay out these requirements in the regulations rather than cross-reference these requirements to the MAOP reconfirmation provisions. Additionally, PHMSA indicated it would create a stand-alone section to deal with pipeline cracking issues within the IM regulations and would delete a specific reference to ''pipe body cracking'' in the provisions related to electric resistance welded pipe.

Following the discussion, the committee voted 12–0 that the provisions related to IM clarifications regarding manufacturing and construction defects were technically feasible, reasonable, cost-effective, and practicable if PHMSA made the changes it proposed during the meeting, created a new, stand-alone section for addressing pipeline cracking within the IM regulations, deleted the phrase related to ''pipe body cracking,'' and considered allowing other test procedures for determining whether manufacturing- and construction-related defects were stable.

MAOP Exceedances (§§ 191.23, 191.25)

In the NPRM, PHMSA proposed requiring operators to report each exceedance of the MAOP that exceeds the build-up allowed for the operation of pressure-limiting or control devices per the congressional mandate provided in the 2011 Pipeline Safety Act, which requires operators to report such exceedances on or before the 5th day

following the date on which the exceedance occurs.

During the public comment period of the June 7, 2017, meeting, a commenter expressed concern that being required to report an exceedance within 5 days might be problematic where an ongoing investigation might preclude an operator from being able to complete a full safety-related condition report. The GPAC considered this viewpoint but noted that the 5-day reporting requirement was prescribed by statute, and PHMSA does not have discretion when implementing that deadline. The GPAC, echoing another comment from the public, discussed whether the provision would be applicable to gathering lines. PHMSA, in response, noted that the requirement would be limited to gas transmission lines only. Following the discussion, the GPAC voted 11–0 that the provision was technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that this provision does not apply to gathering lines.

Verification of Pipeline Material Properties and Attributes (§ 192.607)

In the NPRM, PHMSA proposed a process for operators to re-establish material properties on pipelines where those attributes may be unknown. The process was an opportunistic sampling approach that did not require any mandatory excavations and allowed operators to verify material properties of pipelines as opportunities presented themselves during normal operations and maintenance, such as excavations for the repair of anomalies.

The GPAC had a robust discussion on the proposed material properties verification requirements and wanted to clarify that two separate activities—MAOP reconfirmation and the application of IM principles—drive the need for material properties verification and should be addressed separately. Overall, the GPAC was supportive of PHMSA's opportunistic approach for verifying material properties. During the public comment period, members representing the pipeline industry suggested PHMSA allow a statistical sampling plan developed by operators instead of prescribing a specific number of samples needed. PHMSA clarified that it expected a 1 pipe-per-mile sampling standard in most cases.

At the December 2017 GPAC meeting, some GPAC members expressed concern with the specific attributes PHMSA was proposing operators collect and verify. There was also some discussion regarding how the notification procedure PHMSA proposed might be cumbersome if operators would be required to wait on a response or action from PHMSA every time an operator wanted to submit an alternative plan. The GPAC suggested adding language where, if PHMSA was to object to an operator notification, they would have to object within 90 days. If PHMSA did not object within 90 days, the operator would be free to go forward with the intended action.

Following the discussion, the GPAC voted 12–0 that the provisions related to material properties verification were technically feasible, reasonable, cost-effective, and practicable if the following changes were made:

- Clarify that material properties verification applies to onshore steel transmission lines only, and not distribution or gathering lines.
- Remove the applicability criteria of the section and make the material properties verification provisions a procedure that operators can use for obtaining missing or inadequate records or verifying pipeline attributes if required by the MAOP reconfirmation provisions or other code sections. The committee agreed to address the applicability of the material properties verification requirements under each of the MAOP reconfirmation methods and other sections as appropriate.
- Delete the requirements for creating a material properties verification program plan.
- Drop the list of mandatory attributes operators would be required to verify but require that operators keep any records developed through this material properties verification method.
- Retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to use their own statistical approach and submit a notification to PHMSA with their method. Establish a minimum standard of a 95% confidence level for operator statistical methods submitted to PHMSA.
- Retain flexibility to allow either destructive or non-destructive tests when verification is needed.
- Incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. PHMSA will notify the operator if additional review time is needed.
- Revise the paragraph to accommodate situations where a single material properties verification test is needed (*e.g.,* additional information is needed for an anomaly evaluation/repair).
- Drop accuracy specifications (retain requirement that test methods must be validated and that calibrated equipment be used).
- Drop mandatory requirements for multiple test locations for large excavations (multiple joints within the same excavation).
- Reduce number of quadrants at which NDE tests must be made from 4 to 2.
- Delete specified program requirements for how to address sampling failures and replace with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. Require notification to provide expanded sample program to PHMSA, and require operators establish a minimum standard that sampling programs must be based on a minimum 95% confidence level.
- Clarify the applicability of § 192.607 (d)(3)(i).

Strengthened Assessment Requirements (Appendix F, §§ 192.493, 192.506, 192.921(a))

In the NPRM, PHMSA proposed to clarify the selection and conduct of ILI tools per updated industry standards that would be incorporated by reference, clarify the consideration of uncertainties in ILI reported results, add additional assessment methods to allow greater flexibility to operators, and allow direct assessment as a method only if the pipeline was not piggable. PHMSA also proposed to explicitly allow guided wave ultrasonic testing (GWUT) in the list of integrity assessment methods by codifying in a new Appendix F the current guidelines operators use for submitting GWUT inspection procedures.

For the updated ILI standards, some GPAC members requested PHMSA delete the ''requirements and recommendations'' language in § 192.493 and other places where standards are incorporated by reference to avoid the consequence that non-mandatory recommendations in the standards would become regulatory requirements. Following the discussion, the GPAC voted 10–0 that the provisions related to strengthened assessment requirements pertaining to in-line assessment standards were technically feasible, reasonable, cost-effective, and practicable if PHMSA struck the phrase ''the requirements and recommendations of'' from the appropriate paragraph in § 192.493.

Regarding the usage of assessment methods, certain committee members recommended PHMSA allow the direct assessment method whenever appropriate (*i.e.,* do not restrict the use of direct assessments to unpiggable pipeline segments or when other methods are impractical) and incorporate better language to clarify when it is appropriate for operators to use direct assessments. Similarly, the GPAC suggested PHMSA clarify the regulatory language so that it was clear operators must select the appropriate assessment method based on the applicable threats. The clarification would avoid the implication that operators need to run certain tools against certain threats when there is no evidence or susceptibility of that threat for that particular pipeline segment.

The GPAC also recommended that PHMSA delete the proposed requirement in the baseline assessment method that required a review of ILI results by knowledgeable individuals, since it is duplicative with other existing requirements elsewhere in the regulations. Further, some GPAC members expressed concern that all tools cannot meet the 90 percent tool tolerance that is specified in the referenced industry standard. PHMSA representatives noted that the rule would not require that every tool perform within a 90 percent specification rate, but that actual tool performance should be verified and applied when ILI data is interpreted. As in other sections of the proposed regulations, the committee also requested PHMSA adopt the same objection procedure that the GPAC discussed and approved under the material properties verification provisions for any notification under this section.

Following the discussion, the GPAC voted 10–0 that the provisions related to strengthening the conduct of a baseline integrity assessment were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the requirements to clarify that operators must select assessment methods based on the threats to which the pipeline is susceptible and removed language in the provision that is duplicative with requirements elsewhere in the regulations; clarified that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable; and incorporated the same objection procedure the committee approved for the material properties verification provisions and with a PHMSA review timeframe of 90 days.

In discussing the provisions related to the ''spike'' hydrostatic pressure test method, the committee had several comments and recommendations. Specifically, some GPAC members recommended that the spike test should be performed at a pressure level of 100 percent SMYS, and not 105 percent, to account for varying elevations and test segment lengths. They also suggested that the 30-minute hold time was too long and requested PHMSA consider minimizing the duration of the spike pressure to avoid growing subcritical cracks. Further, the GPAC recommended PHMSA clarify that spike testing should be performed against the threat of ''time-dependent cracking'' and remove instances in other sections of the regulations where PHMSA listed the threats for which a spike pressure test is appropriate. Following the discussion, the committee voted 10–0 that the provisions related to the ''spike'' hydrostatic pressure test method were technically feasible, reasonable, cost-effective, and practicable if PHMSA changed the minimum spike pressure to whichever is lesser: 100 percent SMYS or 1.5 times MAOP, reduced the spike hold time to a minimum of 15 minutes after the spike pressure stabilizes, referred to ''time-dependent cracking'' in the section, incorporated the same objection procedure the committee approved for the material properties verification provisions and with a PHMSA review timeframe of 90 days, and incorporated the term ''qualified technical subject matter expert'' (SME) at the SME requirements.

The GPAC did not have major concerns with incorporating the GWUT procedures into the regulations and voted 13–0 that the provisions related to the GWUT process were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the objection procedure as recommended by GPAC members during the discussion on the proposed material properties verification requirements and considering certain minor technical recommendations made by the GPAC members.

Moderate Consequence Area Definition (§ 192.3)

In the NPRM, PHMSA proposed a new definition for ''Moderate Consequence Areas'' (MCA) which would be areas operators would have to assess per the proposed requirements for performing integrity assessments outside of HCAs. PHMSA proposed to define an MCA as an area in a ''potential impact circle'' [84] with 5 or more buildings intended for human occupancy; an ''occupied site;'' or the right-of-way of an interstate, freeway, expressway, and other principal 4-lane arterial roadway. PHMSA proposed the definition of an ''occupied site'' to be areas or buildings occupied by 5 or more persons, which was the same as an ''identified site'' under the HCA definitions at § 192.903, except that the occupancy threshold was lowered from 20 persons to 5 persons.

The GPAC, based on a comment made by a member of the public, asked if PHMSA could provide more guidance on what a ''piggable'' line is, for the purposes of this definition. The GPAC asked whether PHMSA believed that qualifier applies to pipelines that can be fully assessed by a traditional, free-swimming ILI tool without further modification to the pipeline, and PHMSA noted during the meeting that a ''piggable'' line would be one without physical or operational modifications. The GPAC then suggested PHMSA clarify that definition in the preamble of this final rule.

GPAC members representing the public were concerned about PHMSA's proposal during the meeting to eliminate the concept of an ''occupied site'' from the MCA definition. Industry members argued that, from a practicability standpoint, determining whether five people were in a location at any given time could be difficult, and there was significant overlap between ''occupied sites'' and the class locations that would need to be assessed per the proposal. The GPAC discussed whether some of these sites would be included within an operator's HCA identification program already and, if not, whether operators would be able to otherwise incorporate ''occupied sites'' into their identification and assessment programs.

Several GPAC members discussed whether PHMSA should create a database or provide other guidance on which highways should be included in the MCA definition for consistency between PHMSA, State regulators, and operators. Those comments regarding highways were made following a public comment asking whether certain elevated highways needed to be included.

Following the discussion, the GPAC voted 10–0 that the MCA definition was technically feasible, reasonable, cost-effective, and practicable if PHMSA

[84] A ''potential impact circle'' is defined under § 192.903 as ''a circle of radius equal to the potential impact radius,'' where the ''potential impact radius'' is the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property.

changed the highway description to remove the reference to ''rights-of-way'' and added language so that the highway description includes ''any portion of the paved surface, including shoulders;'' clarified that highways with 4 or more lanes are included within the definition; discussed in the preamble what the definition of ''piggable'' is; and worked with the Federal Highway Administration to provide operators with clear information and discuss it in the preamble of this final rule. Additionally, the GPAC recommended PHMSA modify the term ''occupied sites'' in the definition by removing ''5 or more persons'' and the occupancy timeframe of 50 days, and tie the requirement into the HCA survey for ''identified sites'' as discussed by members and PHMSA at the meeting. Such identification could be made through publicly available databases and class location surveys, and PHMSA was to consider the sites and enforceability per direction by the committee members.

Assessments Outside of HCAs (§ 192.710)

In the NPRM, PHMSA proposed to require operators perform integrity assessments of certain pipelines outside of HCAs. Specifically, operators would perform an initial assessment within 15 years and periodic assessments 20 years thereafter of pipelines in Class 3 and Class 4 locations as well as piggable pipelines in newly-defined ''moderate consequence areas'' as discussed above.

The GPAC, based on a public comment during the meeting, questioned whether the timeframes for the initial assessment and periodic assessments were appropriate. Members debated shortening the time frames and suggested a few timeframes that could be based on a risk-based prioritization and taking into account timeframes for HCA assessments.

Following the discussion, the GPAC voted 10–0 that the provisions related to assessments outside of HCAs were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that direct assessment can be used as an assessment method only if appropriate for the threat being assessed but cannot be used to assess threats for which direct assessment is not suitable; revised the initial assessment and reassessment intervals from 15 years and 20 years, respectively, to 14 years and 10 years, respectively, and with a risk-based prioritization; revised the applicability requirements to apply to lines with MAOPs of 30 percent SMYS or greater; and removed the provisions related to low-stress assessments.

MAOP Reconfirmation (§ 192.624)

In the NPRM, PHMSA proposed a testing regime for (1) pipelines in HCAs, Class 3 or Class 4 locations, or ''piggable'' MCAs that experienced a reportable in-service incident due to certain types of defects since its most recent successful subpart J pressure test, (2) pipelines in HCAs or Class 3 or Class 4 locations that lacked the traceable, verifiable, and complete pressure test records necessary to substantiate the current MAOP, and (3) pipelines in HCAs, Class 3 or Class 4 locations, or piggable MCAs where the operator established the MAOP using the ''grandfather'' clause pursuant to § 192.619(c). PHMSA proposed operators of these pipelines re-confirm the MAOP of those pipelines by choosing and executing one of a variety of methods. Those methods are discussed in more detail in individual sections below.

MAOP Reconfirmation Scope and Completion Date

During the discussion on MAOP reconfirmation, some GPAC members suggested PHMSA revise the applicability of the provisions to remove pipeline segments with prior crack or seam incidents, as those issues would be dealt with in an operator's IM program. Certain committee members recommended PHMSA restrict the scope of the MAOP reconfirmation provisions to pipeline segments with MAOPs of 30 percent SMYS or greater. These members argued that threshold was explicit in the congressional mandate as it pertained to previously untested pipe, and that it was based on the concept that lower-stress lines leak rather than rupture. Members further suggested that the benefit in addressing low-stress lines was not commensurate with the cost of doing so. Other committee members supported retaining the scope of PHMSA's proposals in the NPRM in order to address specific NTSB recommendations.

Following the discussion, the committee voted 13–0 that the provisions related to the scope for MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA removed pipelines with previous reportable incidents due to crack defects from the applicability paragraph; addressed pipeline segments with crack incident history in a new paragraph under the IM requirements; withdrew the definitions for ''modern pipe,'' ''legacy pipe,'' and ''legacy construction techniques;'' revised a reference to necessary records within the applicability paragraph to refer to records needed for MAOP determination and not subpart J pressure test records; and revised the applicability of the requirements for grandfathered lines to apply only to those lines with MAOPs of 30 percent or greater of SMYS. The committee also recommended PHMSA review the costs and benefits of making the requirements applicable to Class 3 and Class 4 non-HCA pipe operating below 30 percent SMYS.

As for the completion date for the MAOP reconfirmation requirements, the GPAC voted 13–0 that the related provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA addressed how the completion plan and completion dates required by the section would apply to pipelines that currently do not meet the applicability conditions but may in the future. The committee suggested PHMSA could add a phrase stating that operators must complete all actions required by the section on 100 percent of the applicable pipeline mileage 15 years after the effective date of the rule or, as soon as practicable but not to exceed 4 years after the pipeline segment first meets the applicability conditions, whichever date is later. The GPAC also recommended that PHMSA consider a waiver or no-objection procedure for extending that timeline past 4 years, if necessary.

MAOP Reconfirmation: Methods 1 and 2 (Pressure Test and Pressure Reduction)

In the NPRM, PHMSA proposed six methods an operator could use if needing to reconfirm MAOP. Method 1, a hydrostatic pressure test, would be conducted at 1.25 times MAOP or the MAOP times the class location test factor, whichever is greater. PHMSA proposed operators use a ''spike'' test method on pipeline segments with reportable in-service incidents due to known manufacturing or construction issues, and PHMSA also proposed operators estimate the remaining life of pipeline segments with crack defects. Method 2, a pressure reduction, would allow operators to reduce the pipeline segment's MAOP to the highest operating pressure divided by 1.25 times MAOP or the class location test factor times MAOP, whichever is greater. Similar to Method 1, PHMSA proposed operators taking a pressure reduction to reconfirm MAOP be required to estimate the remaining life of pipeline segments with crack defects.

The GPAC members representing the industry argued that a ''spike'' test is more appropriate to include under IM requirements and that it is not

appropriate for MAOP reconfirmation. During the meeting, PHMSA noted that if the scope of the MAOP reconfirmation provisions was to be revised to delete lines with crack-like defects, the spike test requirement would not be needed. However, PHMSA would expect the spike test provisions to be utilized when otherwise required by the regulations. GPAC members also suggested adding language to address material properties verification requirements with respect to the information that is needed to conduct a pressure test. At the meeting, PHMSA suggested that the GPAC consider explicitly requiring that any information an operator does not have to perform a successful pressure test in accordance with subpart J (or that is not documented in traceable, verifiable, and complete records) be verified in accordance with the material properties verification provisions.

Following the discussion, the GPAC voted 12–0 that the provisions related to the pressure test method for MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA deleted the spike hydrostatic testing component for pipelines with suspected crack defects and referred to subpart J more broadly instead of certain sections within subpart J. The GPAC also recommended that if the pressure test segment does not have traceable, verifiable, and complete MAOP records, operators should use the best available information upon which the MAOP is currently based to perform the pressure test. The committee recommended PHMSA require operators of such pipeline segments add those segments to its plan for opportunistically verifying material properties in accordance with the material properties verification requirements, noting that most pressure tests will present at least two opportunities for material properties verification at the test manifolds.

As for the pressure reduction method of MAOP reconfirmation, the GPAC voted 12–0 that the related provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA increased the look-back period from 18 months to 5 years and removed the requirement for operators to perform fracture mechanics analysis on those pipeline segments where the pressure is being reduced to reconfirm the MAOP.

MAOP Reconfirmation: Method 3 (Engineering Critical Assessment and Fracture Mechanics)

In the NPRM, PHMSA proposed allowing operators to use an engineering critical assessment (ECA) analysis in conjunction with an ILI assessment to reconfirm a pipeline segment's MAOP where the segment's MAOP would be based upon the lowest predicted failure pressure (PFP) of the segment. This method would require specific technical documentation and material properties verification, and it would require operators analyze crack, metal loss, and interacting defects remaining in the pipe, or that could remain in the pipe, to determine the PFP. The pipeline segment's MAOP would then be established at the lowest PFP divided by 1.25 or by the applicable class location factor listed under the MAOP determination provisions, whichever of those derating factors is greater.

Most of the GPAC discussion on this portion of MAOP reconfirmation related to the specific values used in the fracture mechanics analysis portion of the ECA and whether those requirements would best be located in a section independent from the MAOP reconfirmation requirements. During the meetings, PHMSA noted it would consider creating a stand-alone fracture mechanics section that could be referenced when the procedure is needed or required by other sections of the regulations. PHMSA clarified that fracture mechanics would be needed in the context of MAOP reconfirmation only for the ECA method and ''other technology'' usage under Method 6 where the applicable pipeline segments have cracks or crack-like defects.

Following the discussion, the GPAC voted 12–0 that the provisions related to the ECA method of MAOP reconfirmation and fracture mechanics were technically feasible, reasonable, cost-effective, and practicable if PHMSA moved the fracture mechanics requirements to a stand-alone section in the regulations. The GPAC recommended the section not specify when, or for which pipeline segments, fracture mechanics analysis would be required, but instead provide a procedure by which operators needing to perform fracture mechanics analysis could do so.

The GPAC recommended several changes to the fracture mechanics requirements, including striking cross-references to the MAOP reconfirmation requirements and spike hydrostatic testing requirements, as well as striking the sensitivity analysis requirements and replacing them with a requirement that operators account for model inaccuracies and tolerances. Additionally, the GPAC recommended PHMSA add a paragraph specifying that any records created through the performance of a fracture mechanics analysis must be retained.

There were several technical GPAC recommendations related to the use of Charpy V-notch toughness values in the fracture mechanics analysis. Specifically, the GPAC recommended operators have the ability to use a conservative Charpy V-notch toughness value based on the sampling requirements of the material properties verification provisions, and that operators could use Charpy V-notch toughness values from similar or the same vintage pipe until the properties are obtained through an opportunistic testing program. Further, the GPAC recommended that the default Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) of 13-ft.-lbs. (body) and 4-ft.-lbs. (seam) only apply to pipe with suspected low-toughness properties or unknown toughness properties. Additionally, the GPAC recommended PHMSA include a requirement for operators of pipeline segments with a history of leaks or failures due to cracks to work diligently to obtain toughness data if unknown and use Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) of 5-ft.-lbs. (body) and 1-ft.-lbs. (seam) in the interim. Further, the GPAC suggested PHMSA allow operators to request the use of different default Charpy V-notch toughness values via a 90-day notification to PHMSA.

For the ECA method itself, the committee recommended PHMSA add a requirement to verify material properties in accordance with the material properties verification requirements if the information needed to conduct an ECA is not documented in traceable, verifiable, and complete records. Further, the GPAC recommended that PHMSA not include default Charpy V-notch toughness values or other technical fracture mechanics requirements in the ECA method, as those items would be specified in the new stand-alone fracture mechanics section. Similarly, the GPAC recommended removing ILI tool performance specifications and replacing them with a requirement to verify tool performance using unity plots or equivalent technologies.

MAOP Reconfirmation: Methods 4, 5, and 6 (Pipe Replacement, Small-Diameter & Potential Impact Radius Pressure Reduction, and Other Technology)

In the NPRM, PHMSA proposed three additional methods operators could use to reconfirm a pipeline's MAOP. Method 4, pipe replacement, would require operators to replace pipe for

which they have inadequate records or pipe that was not previously tested due to the grandfather clause in § 192.619(c). Method 5, as proposed, was applicable to low-stress, small diameter, and small potential impact radius (PIR) lines,[85] and would require operators to take a 10 percent pressure cut as well as perform more frequent patrols and leak surveys. Method 6, ''other technology,'' would allow operators to use an alternative method, with notification to PHMSA, to reconfirm the MAOP of their applicable pipeline segments.

The GPAC had no major comments regarding Method 4, pipe replacement. For Method 5, GPAC members representing the industry questioned the need for the compensatory safety measures, such as the additional patrols and leak surveys, in conjunction with the 10 percent pressure reduction. They also supported public comments that promoted expanding the applicability of Method 5 beyond the prescribed pipe diameter of less than or equal to 8 inches and the operating pressure of below 30 percent SMYS. During the meeting, PHMSA noted it could drop the diameter and operating pressure requirements from the applicability and use the prescribed PIR of 150 feet or less as a proxy for those risk factors. Additionally, PHMSA noted it would expand the look-back period to 5 years to be consistent with committee and public comments regarding the pressure reduction method (Method 2) of MAOP reconfirmation discussed earlier. With regard to the ''other technology'' method, committee members suggested using the notification procedure developed for the material properties verification requirements, and PHMSA acknowledged it could be included here as well.

Following the discussion, the committee voted 11–0 that the provisions related to the pipe replacement, pressure reduction for small PIR and diameter lines, and ''other technology'' methods of MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA made certain changes. For Method 4, pipe replacement, the committee had no significant comments or changes. For Method 5, the small PIR and diameter pressure reduction method, the GPAC recommended PHMSA delete the size and pressure criteria, limiting the requirement to those lines with a PIR of 150 feet or less; remove the external corrosion direct assessment, crack analysis program, odorization, and fracture mechanics analysis requirements; and change the frequency of patrols and surveys to 4 times per year in Class 1 and Class 2 locations and 6 times per year in Class 3 and Class 4 locations. For Method 6, the ''other technology'' method, the GPAC recommended PHMSA incorporate the same 90-day notification and objection procedure the GPAC approved for the material properties verification requirements.

MAOP Reconfirmation: Recordkeeping and Notification

The GPAC also voted on the notification procedure and recordkeeping requirements of the MAOP reconfirmation requirements. As there were no substantial GPAC comments on these issues, the GPAC voted 11–0 that the provisions are technically feasible, reasonable, cost-effective, and practicable if PHMSA provided guidance regarding what ''traceable, verifiable, and complete'' records are in the preamble, and if the notification procedure is retained as it was proposed in the NPRM, but incorporating the same 90-day notification and objection procedure the committee approved for the material properties verification requirements into any notification required under the MAOP reconfirmation requirements.

Other MAOP Amendments (§§ 192.503, 192.605(b)(5), 192.619(a)(2), 192.619(a)(4), 192.619(e), 192.619(f))

PHMSA presented to the committee issues related to other portions of MAOP determination [86] that had cross-references to MAOP reconfirmation methods or other areas of the proposed regulations. More specifically, the GPAC was to consider recommending PHMSA eliminate duplications in scope between the MAOP determination provisions and the MAOP reconfirmation provisions, and eliminate a duplicative revision to the subpart J pressure test general requirements that was referenced adequately elsewhere in the proposal. PHMSA also proposed that the establishment of MAOP under § 192.619 should rely on traceable, verifiable, and complete records, and therefore cross-referenced the material properties verification provisions with the MAOP determination provisions. Similarly, PHMSA added a paragraph to the existing MAOP determination provisions to more clearly specify that operators must have records to substantiate the MAOP of their pipeline segments. To address an NTSB recommendation from the PG&E incident, PHMSA also proposed requiring that the MAOP pressure limitation factor specified in the MAOP determination section of the regulations for Class 1 pipeline segments be based on the subpart J test pressure divided by 1.25, whereas the existing requirement was the test pressure divided by 1.1. Finally, PHMSA proposed adding a clarification that the requirement for overpressure protection applied to pipeline segments where the MAOP was established using one of the six methods under MAOP reconfirmation. However, PHMSA noted in response to public comment that the clarification seemed to be overly confusing and should be withdrawn.

The GPAC reviewed and discussed PHMSA's proposed changes to the other MAOP-related provisions, voting 12–0 that the provisions are technically feasible, reasonable, cost-effective, and practicable if PHMSA considered editorially restructuring the applicability of the MAOP determination provisions; clarifying that the recordkeeping requirements specified under MAOP determination only apply to onshore, steel, gas transmission pipelines; and clarifying that the MAOP recordkeeping requirements are not retroactive. The GPAC suggested this be clarified by stating existing records for pipelines installed on or before the effective date of the rule must be kept for the life of the pipeline, that pipelines installed after the effective date of the rule must make and retain records as required for the life of the pipeline, and that MAOP records are required for any pipeline placed in service after the effective date of the rule. The GPAC noted that other sections, including the MAOP reconfirmation and material properties verification requirements, would require when and for which pipeline segments where MAOP records are not documented in a traceable, verifiable, and complete manner would need to be verified.

Changes From the GPAC Recommendations

In this final rule, PHMSA considered the recommendations of the GPAC and adopted them as PHMSA deemed appropriate. However, there were recommendations from the GPAC that PHMSA considered but did not adopt. To summarize, the major changes PHMSA made in this rule that deviate from the GPAC recommendations are as follows:

(1) When discussing the other proposed issues related to the MAOP requirements, the GPAC recommended

[85] These lines would be lines operating below 30 percent SMYS with diameters of 8 inches or less and PIRs of 150 feet or less.

[86] See § 192.619.

PHMSA consider moving § 192.619(e) to be a subsection of § 192.619(a) and consider referencing section § 192.624 in § 192.619(a). PHMSA did not implement this recommendation because MAOP reconfirmation for grandfathered segments is not applicable for new pipeline segments.

(2) When considering the IM clarifications at § 192.917, the GPAC recommended PHMSA consider removing the term ''hydrostatic'' from the testing requirements at § 192.917(e)(3), which deals with manufacturing and construction defects, and allow other authorized testing procedures. PHMSA is not implementing this recommendation because allowing pneumatic tests would be a safety concern to the public and operating personnel.

(3) When discussing the assessment requirements for non-HCAs under proposed § 192.710, the GPAC recommended PHMSA change the ''discovery of condition'' period allotted from 180 to 240 days. PHMSA is not implementing this suggestion from the GPAC and is retaining the 180-day timeframe for operators to determine whether a condition presents a potential threat to the integrity of the pipeline.

(4) PHMSA added a notification requirement for the use of other technology under the non-HCA assessment requirements at § 192.710. While the GPAC did not specifically request PHMSA make this change, the GPAC was generally supportive of incorporating the notification procedure the committee agreed to under the proposed material properties verification requirements for other applications.

(5) Regarding the requirements for the scope of MAOP reconfirmation, the GPAC recommended PHMSA review the costs and benefits of including Class 3 and Class 4 pipelines not located in HCAs and that operate at less than 30 percent SMYS. PHMSA did consider this as an alternative in the RIA but chose not to move forward with the proposal as suggested as it is outside the scope of the mandate.

(6) Regarding the MCA definition, the GPAC recommended PHMSA consider modifying the term ''occupied sites'' within the definition by removing reference to ''5 or more persons'' and the timeframe of 50 days and tying the requirement for identifying occupied sites to the HCA ''identified sites'' survey requirement as discussed by members and PHMSA at the meeting. In this final rule, PHMSA chose to delete the term ''occupied sites'' from the MCA definition and from the general definitions section of part 192.

(7) PHMSA moved the specific ECA requirements outside of the MAOP reconfirmation section into a new stand-alone § 192.632. The MAOP reconfirmation requirements regarding the ECA method at § 192.624(c)(3) and the ECA requirements in § 192.632 will cross-reference each other. PHMSA made this change to streamline the MAOP reconfirmation provisions and improve the readability of the requirements. No substantive changes were made to the procedure in connection with this reorganization; this was a stylistic change only.

V. Section-by-Section Analysis

§ 191.23 Reporting Safety-Related Conditions

Section 23 of the 2011 Pipeline Safety Act requires operators to report each exceedance of MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. On December 21, 2012, PHMSA published advisory bulletin ADB–2012–11, which advised operators of their responsibility under section 23 of the 2011 Pipeline Safety Act to report such exceedances. PHMSA is revising § 191.23 to codify this statutory requirement.

§ 191.25 Filing Safety-Related Condition Reports

Section 23 of the 2011 Pipeline Safety Act requires operators to report each exceedance of the MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. As described above, PHMSA is revising § 191.23 to codify this requirement. Section 191.25 is also revised to make conforming edits and comply with the mandatory 5-day reporting deadline specified in section 23 of the 2011 Pipeline Safety Act.

§ 192.3 Definitions

Section 192.3 provides definitions for various terms used throughout part 192. In support of other regulations adopted in this final rule, PHMSA is amending the proposed definition of ''*Moderate consequence area.*'' This change will define this term as it is used throughout part 192.

The definition of a ''*moderate consequence area,*'' or MCA, is based on similar methodology used to define ''*high consequence area,*'' or HCA in § 192.903. Moderate consequence areas will define the subset of non-HCA locations where integrity assessments are required (§ 192.710) and where MAOP reconfirmation is required (§ 192.624). The criteria for determining MCA locations differs from the criteria currently used to identify HCAs in that the threshold for buildings intended for human occupancy located within the potential impact radius is lowered from 20 to 5, and identified sites are excluded. In response to NTSB recommendation P–14–01, which was issued as a result of the incident near Sissonville, WV, the MCA definition also includes locations where interstate highways, freeways, expressways, and other principal 4-or-more-lane arterial roadways are located within the potential impact radius.

PHMSA is also adopting a definition of an ''*engineering critical assessment,*'' as that term will be used in §§ 192.624 and 192.632. More specifically, the ECA is a documented analytical procedure that operators can use to determine the maximum tolerable size for pipeline imperfections based on the MAOP of the particular pipeline segment. Operators can use an ECA in conjunction with an ILI inspection as one of the methods to reconfirm MAOP, if required.

§ 192.5 Class Locations

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that an important aspect of compliance with this requirement is to assure that pipeline class location records are complete and accurate. This final rule adds a new paragraph, § 192.5(d), to require each operator of transmission pipelines to maintain records documenting the current class location of each pipeline segment and demonstrating how an operator determined each current class location in accordance with this section.

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

Section 192.7 lists documents that are incorporated by reference in part 192. PHMSA is making conforming amendments to § 192.7 in the rule text to reflect other changes adopted in this final rule.

§ 192.9 What requirements apply to gathering lines?

This final rule codifies new standards for gas transmission pipelines, most of which are not intended to be applied to gas gathering pipelines. PHMSA is making conforming amendments to § 192.9 to clarify which provisions

apply only to gas transmission pipelines and not to gas gathering pipelines.

§ 192.18 How To Notify PHMSA

This final rule allows operators to notify PHMSA of proposed alternative approaches to achieving the objective of the minimum safety standards in several different regulatory sections. These notification procedures for alternative actions are comparable to the existing notification requirements in subpart O for the integrity management regulations. Because PHMSA is expanding the use of notifications to pipeline segments for which subpart O does not apply (*i.e.,* to non-HCA pipeline segments), PHMSA is adding a new § 192.18 in subpart A that contains the procedure for submitting such notifications for any pipeline segment.

§ 192.67 Records: Material Properties

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline material properties records are complete and accurate. This final rule moves the original § 192.67 to § 192.69 and adds in its place a new § 192.67 that requires each operator of gas transmission pipelines installed after the effective date of this final rule to collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured. The physical characteristics an operator must keep documented include diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition. These requirements also apply to any new materials or components that are put on existing pipelines. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. These recordkeeping requirements apply to offshore gathering lines and Type A gathering lines in accordance with § 192.9.

Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.69 Storage and Handling of Plastic Pipe and Associated Components

Previous § 192.67, titled ''Storage and handling of plastic pipe and associated components,'' was created as a part of the Plastic Pipe rule, which was published on November 20, 2018 (83 FR 58716). PHMSA is redesignating that section in this final rule to a new § 192.69. No other changes have been made to the section.

§ 192.127 Records: Pipe Design

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipe design records are complete and accurate. For pipelines installed after the effective date of this final rule, this final rule adds a new § 192.127 to require each operator of gas transmission pipelines to collect or make, and retain for the life of the pipeline, records documenting pipe design to withstand anticipated external pressures and determination of design pressure for steel pipe. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.150 Passage of Internal Inspection Devices

The current pipeline safety regulations in § 192.150 require that pipelines be designed and constructed to accommodate in-line inspection devices. Prior to this rulemaking, part 192 was silent on technical standards or guidelines for implementing requirements to assure pipelines are designed and constructed for in-line inspection assessments. Previously, there was no consensus industry standard that addressed design and construction requirements for in-line inspection assessments. NACE Standard Practice, NACE SP0102–2010, ''In-line Inspection of Pipelines,'' has since been published and provides guidance on this issue in section 7. The incorporation of this standard into the Federal Pipeline Safety Regulations at § 192.150 will promote a higher level of safety by establishing consistent standards for the design and construction of pipelines to accommodate in-line inspection devices.

§ 192.205 Records: Pipeline Components

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline component records are complete and accurate. For pipelines installed after the effective date of this final rule, this final rule adds a new § 192.205 to require each operator of gas transmission pipelines to collect or make, and retain for the operational life of the component, records documenting manufacturing and testing information for valves and other pipeline components. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.227 Qualification of Welders

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline welding qualification records are complete and accurate. This final rule adds a new paragraph, § 192.227(c), to require each operator of gas transmission pipelines to make and retain records demonstrating each individual welder's qualification in accordance with this section for a minimum of 5 years following construction. This requirement will apply to pipelines installed after one year from the effective date of the rule.

§ 192.285 Plastic Pipe: Qualifying Persons To Make Joints

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and

operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that plastic pipeline qualification records are complete and accurate. This final rule adds a new paragraph, § 192.285(e), to require each operator of gas transmission pipelines to make and retain records demonstrating a person's plastic pipe joining qualifications in accordance with this section for a minimum of 5 years following construction. This requirement will apply to pipelines installed after one year from the effective date of the rule.

§ 192.493 In-Line Inspection of Pipelines

The current pipeline safety regulations at §§ 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances (*e.g.,* IM assessments for pipelines in HCAs) and allow the use of ILI tools for these assessments. Operators of gas transmission pipelines are required to follow the requirements of ASME/ANSI B31.8S, ''Managing System Integrity of Gas Pipelines,'' in conducting their IM activities. ASME B31.8S provides limited guidance for conducting ILI assessments. Presently, part 192 is silent on the technical standards or guidelines for performing ILI assessments or implementing these requirements. When the IM regulations were initially promulgated, there were no uniform industry standards for ILI assessments. Three related standards have since been published:

- API STD 1163–2013, ''In-Line Inspection Systems Qualification Standard.'' This Standard serves as an umbrella document to be used with and as a complement to the NACE and ASNT standards below, which are incorporated by reference in API STD 1163.
- NACE Standard Practice, NACE SP0102–2010, ''In-line Inspection of Pipelines.''
- ANSI/ASNT ILI–PQ–2005 (2010), ''In-line Inspection Personnel Qualification and Certification.''

API 1163–2013 is more comprehensive and rigorous than the current requirements in 49 CFR part 192. The incorporation of this standard into the Federal Pipeline Safety Regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software utilized by the ILI industry. The API standard addresses in detail each of the following aspects of ILI inspections, most of which are not currently addressed in the regulations:

- Systems qualification process.
- Personnel qualification.
- ILI system selection.
- Qualification of performance specifications.
- System operational validation.
- System results qualification.
- Reporting requirements.
- Quality management system.

The NACE standard covers in detail each of the following aspects of ILI assessments, most of which are not currently addressed in part 192 or in ASME B31.8S:

- Tool selection.
- Evaluation of pipeline compatibility with ILI.
- Logistical guidelines, which includes survey acceptance criteria and reporting.
- Scheduling.
- New construction (planning for future ILI in new lines).
- Data analysis.
- Data management.

The NACE standard provides a standardized questionnaire and specifies that the completed questionnaire should be provided to the ILI vendor. The questionnaire lists relevant parameters and characteristics of the pipeline section to be inspected. PHMSA determined that the consistency, accuracy, and quality of pipeline in-line inspections would be improved by incorporating the consensus NACE standard into the regulations.

The NACE standard applies to ''free swimming'' inspection tools that are carried down the pipeline by the transported product. It does not apply to tethered or remotely controlled ILI tools, which can also be used in special circumstances (*e.g.,* examination of laterals). While their use is less prevalent than free-swimming tools, some pipeline IM assessments have been conducted using tethered or remotely controlled ILI tools. PHMSA determined that many of the provisions in the NACE standard can be applied to tethered or remotely controlled ILI tools. Therefore, PHMSA is amending the Federal Pipeline Safety Regulations to allow the use of these tools, provided they comply with the applicable sections of the NACE standard.

The ANSI/ASNT standard provides for qualification and certification requirements that are not addressed by 49 CFR part 192. The incorporation of this standard into the regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes and software utilized by the ILI industry. The ANSI/ASNT standard addresses in detail each of the following aspects, which are not currently addressed in the regulations:

- Requirements for written procedures.
- Personnel qualification levels.
- Education, training and experience requirements.
- Training programs.
- Examinations (testing of personnel).
- Personnel certification and recertification.
- Personnel technical performance evaluations.

The final rule adds a new § 192.493 to require compliance with the three consensus standards discussed above when conducting ILI of pipelines.

§ 192.506 Transmission Lines: Spike Hydrostatic Pressure Test

A pressure test that incorporates a short duration ''spike'' pressure is a proven means to confirm the strength of pipe with known or suspected threats of cracks or crack-like defects (*e.g.,* stress corrosion cracking, longitudinal seam defects, etc.). Currently, part 192 does not include minimum standards for such a spike hydrostatic pressure test. This final rule adds a new § 192.506 to codify the minimum standards for performing spike hydrostatic pressure tests when operators are required to, or elect to, use this assessment method. Under the spike hydrostatic pressure test requirements, an operator may use other technologies or processes equivalent to a spike hydrostatic pressure test with justification and notification in accordance with § 192.18.

§ 192.517 Records: Tests

Section 192.517 prescribes the recordkeeping requirements for each test performed under §§ 192.505 and 192.507. PHMSA is making conforming amendments to § 192.517 to add the recordkeeping requirements for the new § 192.506.

§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore Steel Transmission Pipelines

Section 23 of the 2011 Pipeline Safety Act mandates the Secretary of Transportation to require operators of gas transmission pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 locations in HCAs to verify records to ensure the records accurately reflect the physical and operational characteristics of the pipelines and confirm the MAOP of the pipelines established by the operator (49 U.S.C. 60139). PHMSA issued Advisory Bulletin 11–01 on January 10, 2011 (76

FR 1504), and Advisory Bulletin 12–06 on May 7, 2012 (77 FR 26822), to inform operators of this requirement. Operators have submitted information in their Annual Reports (starting for calendar year 2012) indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP and that some operators do not have traceable, verifiable, and complete records that accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA has determined that additional regulations are needed to implement the 2011 Pipeline Safety Act. This final rule promulgates specific criteria for determining which pipeline segments must undergo examinations and tests to understand and document physical and material properties and reconfirm a proper MAOP. For operators that do not have traceable, verifiable, and complete documentation for the physical pipeline characteristics and attributes of a pipeline segment, PHMSA is adding a new § 192.607 that contains the procedure for verifying and documenting pipeline physical properties and attributes that are not documented in traceable, verifiable, and complete records and to establish standards for performing these actions. For operators of certain pipelines lacking the necessary records to substantiate MAOP, PHMSA is also adding § 192.624, which provides operators several methods for reconfirming a pipeline segment's MAOP.

The new material properties verification requirements at § 192.607 include the scope of information needed and the methodology for verifying material properties and attributes of pipelines. The most difficult information to obtain, from a technical perspective, is the strength of the pipeline's steel. Conventional techniques to obtain that data would include cutting out a piece of pipe and destructively testing it to determine the yield and ultimate tensile strength. In this final rule, PHMSA is providing operators with flexibility by allowing the use of non-destructive techniques that have been validated to produce accurate results for the grade and type of pipe being evaluated (see § 192.624).

Another issue regarding material properties verification is the cost associated with excavating the pipeline to verify material properties and determining how much pipeline needs to be exposed and tested to have assurance of the accuracy of the verification. PHMSA addresses these issues within this final rule by specifying that operators can take advantage of opportunities when the pipeline is already being exposed, such as when maintenance activity is occurring and when anomaly repairs are being made, to verify material properties that are not documented in traceable, verifiable, and complete records. For example, PHMSA considers excavations associated with the direct examination of anomalies, pipeline relocations at road crossings and river or stream crossings, pipe upgrades for class location changes, pipe cut-outs for hydrostatic pressure tests, and excavations where pipe is replaced due to anomalies to be opportunities to perform material properties verification. Over time, pipeline operators will develop a substantial set of traceable, verifiable, and complete material properties data, which will provide assurance that material properties are reliably known for the population of segments that did not have pipeline physical properties and attributes documented in traceable, verifiable, and complete records previously. Through this final rule, PHMSA is requiring that operators continue this opportunistic material properties verification process until the operator has completed enough verifications to obtain a high level of confidence that only a small percentage of pipeline segments have physical pipeline characteristics and attributes that are not verified or are otherwise inconsistent with all available information or operators' past assumptions. This final rule specifies the number of excavations required for operators to achieve this level of confidence.

Operators may use an alternative sampling approach that differs from the sampling approach specified in the requirements if they notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.

Requirements are also included in the material properties verification section to ensure that operators document the results of the material properties verification process in records that must be retained for the life of the pipeline.

§ 192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

The NTSB report on the PG&E incident included a recommendation (P–11–15) that PHMSA amend its regulations so that manufacturing-and construction-related defects can only be considered ''stable'' if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP. This final rule revises the test pressure factors in § 192.619(a)(2)(ii) to correspond to at least 1.25 times MAOP for pipelines installed after the effective date of this rule.

The NTSB also recommended repealing § 192.619(c), commonly referred to as the ''grandfather clause,'' and requiring that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (recommendation P–11–14). Similarly, section 23 of the 2011 Pipeline Safety Act requires that selected pipeline segments in certain locations with previously untested pipe (*i.e.,* the MAOP is established under § 192.619(c)) or without MAOP records be tested with a pressure test or equivalent means to reconfirm the pipeline's MAOP. These requirements are addressed in the new § 192.624 and are described in more detail in the following section. This final rule also makes conforming changes to § 192.619 to require that operators of pipeline segments to which § 192.624 applies establish and document the segment's MAOP in accordance with § 192.624.

§ 192.624 Maximum Allowable Operating Pressure Reconfirmation: Onshore Steel Transmission Pipelines

Section 23 of the 2011 Pipeline Safety Act requires the verification of records for pipe in Class 3 and Class 4 locations, and high-consequence areas in Class 1 and Class 2 locations, to ensure they accurately reflect the physical and operational characteristics of the pipelines and confirm the established MAOP of the pipelines. Operators have submitted information in annual reports (beginning in calendar year 2012) indicating that some gas transmission pipeline segments do not have adequate material properties records or testing records to confirm physical and operational characteristics and to establish MAOP. For these pipelines, the 2011 Pipeline Safety Act requires that PHMSA promulgate regulations to require operators to reconfirm MAOP as expeditiously as economically feasible. The statute also requires PHMSA to issue regulations that require previously untested pipeline segments located in HCAs and operating at greater than 30 percent SMYS be tested to confirm the material strength of the pipelines. Such tests must be performed by pressure testing or other methods determined by the Secretary to be of equal or greater effectiveness.

As a result of its investigation of the PG&E incident, the NTSB issued two related recommendations. NTSB recommended that PHMSA repeal § 192.619(c), commonly referred to as

the ''grandfather clause,'' and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (P–11–14). The NTSB also recommended that PHMSA amend the Federal Pipeline Safety Regulations so that manufacturing- and construction-related defects can only be considered stable if a pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP (P–11–15).

Through this final rule, PHMSA is finalizing a new § 192.624 to address these mandates and recommendations. This final rule requires that operators reconfirm and document MAOP for certain onshore steel gas transmission pipelines located in HCAs or MCAs that meet one or more of the criteria specified in § 192.624(a). More specifically, this section applies to (1) pipelines in HCAs or Class 3 or Class 4 locations lacking traceable, verifiable, and complete records necessary to establish the MAOP (per § 192.619(a)) for the pipeline segment, including, but not limited to, hydrostatic pressure test records required by § 192.517(a); and (2) pipelines where the MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of SMYS, and the pipeline is located in an HCA, a Class 3 or Class 4 location, or an MCA that can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''). This approach implements the mandate in the 2011 Pipeline Safety Act for pipeline segments in HCAs and Class 3 and Class 4 locations (49 U.S.C. 60139). In addition, the scope includes pipeline segments in the newly defined MCAs. This approach is intended to address the NTSB recommendations and to provide increased safety in areas where a pipeline rupture would have a significant impact on the public or the environment. Though PHMSA is subjecting certain grandfathered pipeline segments to the MAOP reconfirmation requirements of § 192.624, PHMSA is not repealing § 192.619(c) for pipeline segments located outside of HCAs, Class 3 or Class 4 locations, or MCAs that can accommodate inspection by means of instrumented ILI tools. Previously grandfathered pipelines that reconfirm MAOP using one of the methods of § 192.624 that operate above 72 percent SMYS may continue to operate at the reconfirmed pressure.

The methods to reconfirm MAOP are specified in § 192.624 and are as follows:

Method 1—Pressure test. The pressure test method as specified in section 23 of the 2011 Pipeline Safety Act. Operators choosing to pressure test must also verify material property records in accordance with § 192.607. PHMSA notes that a pressure test requires the cutout of pipe at test manifold sites and those pipe cutouts would be a prime example of pipe that could and should be tested through the material properties verification procedure, if necessary. In accordance with the statute, PHMSA determined that the following methods (2) through (6) are equally effective as a pressure test for the purposes of reconfirming MAOP.

Method 2—Pressure reduction. De-rating the pipeline segment so that the new MAOP is less than the historical actual sustained operating pressure by using a pressure test safety factor of 0.80 (for Class 1 and Class 2 locations) or 0.67 (for Class 3 and Class 4 locations) times the sustained operating pressure (equivalent to a pressure test using gas or water as the test medium with a test pressure of 1.25 times MAOP for Class 1 and Class 2 locations and 1.5 times MAOP for Class 3 and Class 4 locations).

Method 3—Engineering critical assessment. An in-line inspection, previously performed pressure test, or alternative technology and engineering critical assessment process using technical analysis with acceptance criteria to establish a safety margin equivalent to that provided by a new pressure test. PHMSA organized the ECA process requirements under a new § 192.632 and established the technical requirements for analyzing the predicted failure pressure as a part of the ECA analysis in a new § 192.712. If an operator chooses the ECA method for MAOP reconfirmation but does not have any of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy V-notch toughness values, if applicable), the operator must include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

Method 4—Pipe replacement. Replacement of the pipe, which would require a new pressure test that conforms with subpart J before the pipe is placed into service.

Method 5—Pressure reduction for pipeline segments with small potential impact radii. For pipeline segments with a potential impact radius of less than or equal to 150 feet, a pressure reduction using a safety factor of 0.90 times the sustained operating pressure is allowed (equivalent to a pressure test of 1.11 times MAOP), supplemented with additional preventive and mitigative measures specified in this final rule.

Method 6—Alternative technology. Other technology that the operator demonstrates provides an equivalent or greater level of safety, provided PHMSA is notified in advance in accordance with § 192.18.

Lastly, this final rule includes a new paragraph, § 192.624(f), to clearly specify that records created while reconfirming MAOP must be retained for the life of the pipeline.

§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore Steel Transmission Pipelines

The requirements for reconfirming MAOP in the new § 192.624 include an option for operators to perform an engineering critical assessment, or ECA, to reconfirm MAOP in lieu of pressure testing and the other methods provided. The requirements for conducting such an ECA were proposed under the MAOP reconfirmation requirements at § 192.624(c)(3); however, PHMSA has moved the ECA requirements to a new, stand-alone section and cross-referenced those requirements in order to improve the readability of the MAOP reconfirmation requirements.

Operators choosing the ECA method for MAOP reconfirmation may perform an in-line inspection and a technical analysis with acceptance criteria to establish a safety margin equivalent to that provided by a pressure test. PHMSA established the technical requirements for analyzing the predicted failure pressure as a part of the ECA analysis in a new § 192.712, and those requirements are cross-referenced within this ECA process.

Although PHMSA expects that most operators will use an ECA in conjunction with in-line inspection, PHMSA would also allow operators with past, valid pressure tests to calculate the largest defects that could have survived the pressure test and analyze the postulated defects to calculate a predicted failure pressure with which to establish MAOP. This approach might be desirable for operators in certain circumstances, such as for line segments that have valid pressure test records, but that lack other records (such as material strength or pipe wall thickness) necessary to determine design pressure and establish MAOP under the existing § 192.619(a). Another situation for which operators could use this approach would be if the operator has a valid pressure test, but it was not conducted at a test pressure that

was high enough to establish the current MAOP.

Operators with pressure test records meeting the subpart J test requirements may use an ECA by calculating the largest defect that could have survived the pressure test and estimating the flaw growth between the date of the test and the date of the ECA. The ECA is then performed using these postulated defect sizes. In addition, operators must calculate the remaining life of the most severe defects that could have survived the pressure test and establish an appropriate re-assessment interval in accordance with new § 192.712.

If an operator chooses to use ILI to characterize the defects remaining in the pipe segment and the ECA method for MAOP reconfirmation but does not have one or more of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy V-notch toughness values, if applicable), the operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

§ 192.710 Transmission Lines: Assessments Outside of High Consequence Areas

Section 5 of the 2011 Pipeline Safety Act requires, if appropriate, the Secretary of Transportation to issue regulations expanding IM system requirements, or elements thereof, beyond HCAs. Currently, part 192 does not contain any requirement for operators to conduct integrity assessments of onshore transmission pipelines that are not HCA segments, as defined in § 192.903, and are therefore not subject to subpart O. However, only approximately 7 percent of onshore gas transmission pipelines are located in HCAs. Through this final rule, operators are required to periodically assess Class 3 locations, Class 4 locations, and MCAs that can accommodate inspection by means of an instrumented inline inspection tool. The periodic assessment requirements under this section apply to pipelines in these locations with MAOPs greater than or equal to 30 percent of SMYS.

Industry has, as a practical matter, assessed portions of pipelines in non-HCA segments coincident with integrity assessments of HCA pipeline segments. For example, INGAA has noted in comment submissions that approximately 90 percent of Class 3 and Class 4 mileage not in HCAs are presently assessed during IM assessments. This is because, in large part, ILI or pressure testing, by their nature, assess large continuous pipeline segments that may contain some HCA segments but that could also contain significant amounts of non-HCA segments.

While INGAA does not represent all pipeline operators subject to part 192, it does represent the majority of gas transmission operators. PHMSA has determined that, given this level of assessment, it is appropriate and consistent with industry direction to codify requirements for operators to periodically assess certain gas transmission pipelines outside of HCAs to monitor for, detect, and remediate pipeline defects and anomalies. Additionally, to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while minimizing the cost of identifying such locations, PHMSA is basing the requirements for identifying those locations on processes already being implemented by pipeline operators. More specifically, the MCA definition assumes a similar process used for identifying HCAs, with the exception that the threshold for buildings intended for human occupancy located within the potential impact circle is reduced from 20 to 5.

Because significant non-HCA pipeline mileage has been previously assessed in conjunction with the regular assessment of HCA pipeline segments, PHMSA is allowing operators to count those prior assessments as compliant with the new § 192.710 for the purposes of assessing non-HCAs if those assessments were conducted, and threats remediated, in conjunction with an integrity assessment required by subpart O.

This final rule also requires that the assessment required by the new § 192.710 be conducted using the same methods as adopted for HCAs (see § 192.921, below). Operators may use ''other technology'' as an assessment method, provided the operator notifies PHMSA in accordance with § 192.18.

§ 192.712 Analysis of Predicted Failure Pressure

The new requirements for reconfirming MAOP in the new § 192.624 include an option for operators to perform an engineering critical assessment, or ECA, to reconfirm MAOP in lieu of pressure testing and the other methods provided. A key aspect of the ECA analysis is the detailed analysis of the remaining strength of pipe with known or assumed defects. The current Federal Pipeline Safety Regulations in subparts I and O refer to methods for predicting the failure pressure for pipe with corrosion metal loss defects. However, the regulations are silent on performing such analysis for pipe with cracks (including crack-like defects such as selective seam weld corrosion). Therefore, in this final rule, PHMSA is inserting a new section to address the techniques and procedures for analyzing the predicted failure pressures for pipe with corrosion metal loss and cracks or crack-like defects. Examples of technically proven models for calculating predicted failure pressures include: For the brittle failure mode, the Newman-Raju Model [87] and PipeAssess PI™ software; [88] and for the ductile failure mode, Modified Log-Secant Model,[89] API RP 579–1 [90]—Level II or Level III, CorLas™ software,[91] PAFFC Model,[92] and PipeAssess PI™ software. All failure models used for the ECA analysis must be used within its technical parameters for the defect type and the pipe or weld material properties. Conforming changes are being made to applicable sections in subparts I and O to refer to this new section, for consistency, but the basic techniques are unchanged.

As a part of this section, PHMSA is including a new paragraph to address cracks and crack-like defects, which as stated above is a critical function of the ECA analysis. The ECA analysis requires the conservative analysis of any in-service cracks, crack-like defects remaining in the pipe, or the largest possible crack that could remain in the pipe, including crack dimensions (length and depth) to determine the predicted failure pressure (PFP) of each defect; the failure mode (ductile, brittle, or both) for the microstructure; the defect's location and type; the pipeline's operating conditions (including pressure cycling); and failure stress and

[87] Newman, J.C., and Raju; ''Stress Intensity Factors for Cracks in Three Dimensional Finite Bodies Subjected to Tension and Bending Loads;'' *Computational Methods in the Mechanics of Fracture;* Elsevier; 1986; pp. 311–334.

[88] Interim Report for Phase II—Task 5 of the Comprehensive Study to Understand Longitudinal ERW Seam Failures, ''Summary Report for an Integrity Management Software Tool,'' May 2017. *https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=11469.*

[89] ASTM International, ASTM STP 536, ''Failure Stress Levels of Flaws in Pressurized Cylinders,'' 1973.

[90] American Petroleum Institute and American Society of Mechanical Engineers, API 579–1/ASME FFS–1, ''Fitness-For-Service,'' Second Edition, June 2007.

[91] NACE International, NACE Corrosion 96 Paper 255, ''Effect of Stress Corrosion Cracking on Integrity and Remaining Life of Natural Gas Pipelines,'' March 1996.

[92] Pipeline Research Council International, Inc., Topical Report NG–18 No. 193, ''Development and Validation of a Ductile Flaw Growth Analysis for Gas Transmission Line Pipe,'' June 1991.

crack growth analysis to determine the remaining life of the pipeline. An ECA must use the techniques and procedures developed and confirmed through the research findings provided by PHMSA and other reputable technical sources for longitudinal seam and crack growth, such as the Comprehensive Study to Understand Longitudinal ERW Seam Research & Development study task reports: Battelle Final Reports (''Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications''—Task 1.4), Report No. 13–002 (''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams''—Subtask 2.4), Report No. 13–021 (''Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue''—Subtask 2.5), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1''—Task 4.5), which can be found online at: *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.* Operators wanting to use assumed Charpy V-notch toughness values differing from the prescribed values as a part of fracture mechanics analysis must notify PHMSA in accordance with § 192.18.

§ 192.750 Launcher and Receiver Safety

PHMSA has determined that more explicit requirements are needed for safety when performing maintenance activities that use launchers and receivers to insert and remove maintenance tools and devices, as such facilities are subject to pipeline system pressures. The current regulations for hazardous liquid pipelines at 49 CFR part 195 have, since 1981, contained such safety requirements for scraper and sphere facilities (§ 195.426). However, the regulations for natural gas pipelines do not similarly require controls or instrumentation to protect against inadvertent breaches of system integrity due to the incorrect operation of launchers and receivers for ILI tools, scraper, and sphere facilities. Accordingly, this final rule is adding a new § 192.750 to require a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the barrel or a means to prevent opening if pressure has not been relieved.

§ 192.805 Qualification Program

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.805 to refer to the new § 192.18.

§ 192.909 How can an operator change its integrity management program?

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.909 to refer to the new § 192.18.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA is revising § 192.917(a)(3) to include seismicity of the area in evaluating the threat of outside force damage. To address NTSB recommendation P–11–15, PHMSA is also revising the criteria in § 192.917(e)(3) for addressing the threat of manufacturing and construction defects by requiring that a pipeline segment must have been pressure tested to a minimum of 1.25 times MAOP to conclude latent defects are stable. Section 192.917(e)(4) has additional requirements for the assessment of low-frequency ERW pipe with seam failures. It now requires usage of the appropriate technology to assess low-frequency ERW pipe, including seam cracking and selective seam weld corrosion. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.712.

Lastly, the integrity management requirements to address specific threats in § 192.917(e) include requirements for the major causes of pipeline incidents, such as corrosion, third-party damage, cyclic fatigue, manufacturing and construction defects, and electric resistance welded pipe. However, § 192.917(e) does not address cracks and crack-like defects. Therefore, PHMSA is adding a new paragraph, § 192.917(e)(6), to include specific IM requirements for addressing the threat of cracks and crack-like defects (including, but not limited to, stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) comparable to the other types of threats addressed in § 192.917(e).

§ 192.921 How is the baseline assessment to be conducted?

Section 192.921 requires that pipelines subject to the IM regulations have an integrity assessment. The current regulations allow operators to use ILI tools; pressure testing in accordance with subpart J; direct assessment for the threats of external corrosion, internal corrosion, and stress corrosion cracking; and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline. Following the PG&E incident, PHMSA determined that the baseline assessment methods should be clarified and strengthened to emphasize ILI use and pressure testing over direct assessment. At San Bruno, PG&E relied heavily on direct assessment under circumstances for which direct assessment was not effective nor appropriate for the pipeline seam type and the threats to the pipeline. Therefore, this final rule requires that direct assessment only be allowed to assess the threats for which the specific direct assessment process is appropriate.

This final rule also adds three additional assessment methods for operators to use: (1) A ''spike'' hydrostatic pressure test, which is particularly well-suited to address time-dependent threats, such as stress corrosion cracking and other cracking or crack-like defects that can include manufacturing- and construction-related defects; (2) guided wave ultrasonic testing (GWUT), which is particularly appropriate in cases where short pipeline segments, such as road or railroad crossings, are difficult to assess; and (3) excavation with direct *in situ* examination. Based upon the threat assessed, examples of appropriate non-destructive examination methods for *in situ* examination can include ultrasonic testing, phased array ultrasonic testing, inverse wave field extrapolation, radiography, or magnetic particle inspection.

The current regulations indicate that ILI tools are an acceptable assessment method for the threats that the particular ILI tool type can assess. PHMSA is clarifying in this final rule that the use of ILI tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges, and grooves), material cracking and crack-like defects (*e.g.,* stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), and hard spots with cracking. As discussed above, this final rule

strengthens guidance in this area by adding a new § 192.493 to require compliance with the requirements and recommendations of API STD 1163–2005, NACE SP0102–2010, and ANSI/ASNT ILI–PQ–2005 when conducting in-line inspection of pipelines. Accordingly, PHMSA revises § 192.921(a)(1) in this final rule to require compliance with § 192.493 instead of ASME B31.8S for baseline ILI assessments for covered segments.

GWUT has been used by pipeline operators for several years. Previously, operators were required by § 192.921(a)(4) to submit a notification to PHMSA as an ''other technology'' assessment method to use GWUT. In 2007, PHMSA developed guidelines for how it would evaluate notifications for the use of GWUT. These guidelines have been effectively used for over 9 years, and PHMSA has confidence that operators can use GWUT to assess the integrity of short segments of pipe against corrosion threats. In this final rule, PHMSA is incorporating these guidelines into a new Appendix F, which is referenced in § 192.921. Therefore, operators would no longer be required to notify PHMSA to use GWUT.

ASME B31.8S, section 6.1, describes both excavation and direct *in situ* examination as specialized integrity assessment methods applicable to particular circumstances:

> It is important to note that some of the integrity assessment methods discussed in para. 6 only provide indications of defects. Examination using visual inspection and a variety of nondestructive examination (NDE) techniques are required, followed by evaluation of these inspection results in order to characterize the defect. The operator may choose to go directly to examination and evaluation for the entire length of the pipeline segment being assessed, in lieu of conducting inspections. For example, the operator may wish to conduct visual examination of aboveground piping for the external corrosion threat. Since the pipe is accessible for this technique and external corrosion can be readily evaluated, performing in-line inspection is not necessary.

PHMSA is clarifying its requirements to explicitly add excavation and direct *in situ* examination as an acceptable assessment method. As previously discussed under § 192.710, PHMSA intends for operators to assess non-HCA pipe with the same methods as HCA pipe. Therefore, PHMSA has standardized the assessment methods between both the IM and non-IM sections. Operators wishing to use ''other technology'' differing from the prescribed acceptable assessment methods must notify PHMSA in accordance with § 192.18.

§ 192.933 What actions must be taken to address integrity issues?

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.933 to refer to the new § 192.18.

§ 192.935 What additional preventive and mitigative measures must an operator take?

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA is revising § 192.935(b)(2) to include seismicity of the area when evaluating preventive and mitigative measures with respect to the threat of outside force damage.

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

Section 192.937 requires that operators continue to periodically assess HCA pipeline segments and periodically evaluate the integrity of each covered pipeline segment. PHMSA determined that conforming amendments would be needed to implement, and be consistent with, the changes discussed above for § 192.921. Accordingly, this final rule requires that reassessments use the same assessment methods specified in § 192.921. Operators wishing to use ''other technology'' differing from the prescribed acceptable assessment methods must notify PHMSA in accordance with § 192.18.

§ 192.939 What are the required reassessment intervals?

Section 192.939 specifies reassessment intervals for pipelines subject to IM requirements. Section 5 of the 2011 Pipeline Safety Act includes a technical correction that clarified that periodic reassessments must occur at a minimum of once every 7 calendar years, but that the Secretary may extend such deadline for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. PHMSA expects that any justification, at a minimum, must demonstrate that the extension does not pose a safety risk. In this final rule, PHMSA is codifying this technical correction.

As explained in PHMSA IM FAQ–41, the maximum interval for reassessment may be set using the specified number of calendar years. The use of calendar years is specific to gas pipeline reassessment interval years and does not alter the actual year interval requirements which appear elsewhere in the code for various inspection and maintenance requirements.

Additionally, PHMSA is revising § 192.939 to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.939 to refer to the new § 192.18.

§ 192.949 How does an operator notify PHMSA? (Removed and Reserved)

This rulemaking includes several requirements that allow operators to notify PHMSA of proposed alternative approaches to achieving the objective of the minimum safety standards. This is comparable to existing notification requirements in subpart O for pipelines subject to the IM regulations. Because PHMSA is expanding the use of notifications to pipeline segments for which subpart O does not apply (*i.e.,* to non-HCA pipeline segments), PHMSA is adding a new § 192.18 that contains the procedure for submitting such notifications. As such, § 192.949 is no longer needed and is being removed and reserved.

Appendix F to Part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

As discussed under § 192.921 above, a new Appendix F to part 192 is needed to provide specific requirements and acceptance criteria for the use of GWUT as an integrity assessment method. Operators must apply all 18 criteria defined in Appendix F to use GWUT as an integrity assessment method. If an operator applies GWUT technology in a manner that does not conform with the guidelines in Appendix F, it would be considered ''other technology'' for the purposes of §§ 192.710, 192.921, and 192.937.

VI. Standards Incorporated by Reference

A. Summary of New and Revised Standards

Consistent with the amendments in this document, PHMSA is incorporating by reference several standards as described below. Some of these standards are already incorporated by reference into the Federal Pipeline Safety Regulations and are being extended to other sections of the regulations. Other standards provide a technical basis for corresponding regulatory changes in this final rule.

• API STD 1163, ''In-Line Inspection Systems Qualification,'' Second edition, April 2013, Reaffirmed August 2018.

This standard covers the use of ILI systems for onshore and offshore gas and hazardous liquid pipelines. This includes, but is not limited to, tethered, self-propelled, or free-flowing systems for detecting metal loss, cracks, mechanical damage, pipeline geometries, and pipeline location or mapping. The standard applies to both existing and developing technologies. This standard is an umbrella document that provides performance-based requirements for ILI systems, including procedures, personnel, equipment, and associated software. The incorporation of this standard into the Federal Pipeline Safety Regulations will provide rigorous processes for qualifying the equipment, people, processes, and software used in in-line inspections.

• ANSI/ASNT ILI–PQ–2005(2010), ''In-line Inspection Personnel Qualification and Certification,'' Reapproved October 11, 2010.

This standard establishes minimum requirements for the qualification and certification of in-line inspection personnel whose jobs demand specific knowledge of the technical principles of in-line inspection technologies, operations, regulatory requirements, and industry standards as those are applicable to pipeline systems. The employer-based standard includes qualification and certification for Levels I, II, and III. The incorporation of this standard into the Federal Pipeline Safety Regulations provides for certification and qualification requirements that are not otherwise addressed in part 192 and will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software used in in-line inspections.

• NACE Standard Practice 0102–2010, ''In-Line Inspection of Pipelines,'' Revised 2010–03–13.

This standard outlines a process of related activities that a pipeline operator can use to plan, organize, and execute an ILI project, and it includes guidelines pertaining to ILI data management and data analysis. This standard is intended for individuals and teams, including engineers, O&M personnel, technicians, specialists, construction personnel, and inspectors, involved in planning, implementing, and managing ILI projects and programs. The incorporation of this standard into the Federal Pipeline Safety Regulations would promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software used in in-line inspections.

PHMSA is also extending the applicability of the following three currently incorporated-by-reference standards to new sections of the Federal Pipeline Safety Regulations:

• ASME/ANSI B16.5–2003, ''Pipe Flanges and Flanged Fittings,'' October 2004, IBR approved for § 192.607(f).

This standard covers pressure-temperature ratings, materials, dimensions, tolerances, marking, testing, and methods of designating openings for pipe flanges and flanged fittings. The standard includes requirements and recommendations regarding flange bolting, flange gaskets, and flange joints. This standard is intended for manufacturers, owners, employers, users, and others concerned with the specification, buying, maintenance, training, and safe use of valves with pressure equipment. The incorporation of this standard promotes industry best practices and operational, cost, and safety benefits.

• ASME/ANSI B31G–1991 (Reaffirmed 2004), ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' 2004, IBR approved for §§ 192.632(a) and 192.712(b).

This document provides guidance for the evaluation of metal loss in pressurized pipelines and piping systems. It is applicable to all pipelines and piping systems that are part of the scope of the transportation pipeline codes that are part of ASME B31 Code for Pressure Piping, namely: ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids; ASME B31.8, Gas Transmission and Distribution Piping Systems; ASME B31.11, Slurry Transportation Piping Systems; and ASME B31.12, Hydrogen Piping and Pipelines, Part PL.

• AGA, Pipeline Research Committee Project, PR–3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' (December 22, 1989), IBR approved for §§ 192.632(a) and 192.712(b).

This document was developed from the Modified B31G method to allow assessment of a river bottom profile of a corroded area on a pipeline to provide more accurate predictions of the pipeline's remaining strength, and it was adapted into a software program known as RSTRENG. Pipeline operators can use RSTRENG to calculate a pipeline's predicted failure pressure and safe pressure when determining operating pressures and anomaly response times.

The incorporation by reference of ASME/ANSI B31.8S was approved for §§ 192.921 and 192.937 as of January 14, 2004. That approval is unaffected by the section revisions in this final rule.

B. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 60 standards and specifications developed and published by standard developing organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices. ASTM often updates some of its more widely used standards every year, and sometimes multiple editions of standards are published in a given year.

In accordance with the National Technology Transfer and Advancement Act of 1995 (Pub. L. 104–113), PHMSA has the responsibility for determining which currently referenced standards should be updated, revised, or removed, and which standards should be added to 49 CFR parts 192, 193, and 195. Revisions to incorporated by reference materials in parts 192, 193, and 195 are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Public Law 112–90. Section 24 of that law states: ''Beginning 1 year after the date of enactment of this subsection, the Secretary may not issue guidance or a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge, on an internet website.'' 49 U.S.C. 60102(p).

On August 9, 2013, Public Law 113–30 revised 49 U.S.C. 60102(p) to replace ''1 year'' with ''3 years'' and remove the phrases ''guidance or'' and, ''on an internet website.'' This resulted in the current language in 49 U.S.C. 60102(p), which now reads as follows:

Beginning 3 years after the date of enactment of this subsection, the Secretary may not issue a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge.

On November 7, 2014, the Office of the Federal Register issued a final rule that revised 1 CFR 51.5 to require that Federal agencies include a discussion in the preamble of the final rule ''the ways the materials it incorporates by reference are reasonably available to interested parties and how interested parties can obtain the materials.'' 79 FR 66278. In relation to this rulemaking, PHMSA has contacted each SDO and has requested free public access of each standard that has been incorporated by reference. The SDOs agreed to make viewable copies of the incorporated standards available to the public at no cost. Pipeline operators interested in purchasing these standards can contact the individual and applicable standards organizations. The contact information is provided in this rulemaking action, see § 192.7.

In addition, PHMSA will provide individual members of the public temporary access to any standard that is incorporated by reference that is not otherwise available for free. Requests for access can be sent to the following email address: *PHMSAPHPStandards@dot.gov.*

VII. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*). Section 60102 authorizes the Secretary of Transportation to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities, as delegated to the PHMSA Administrator under 49 CFR 1.97.

PHMSA is revising the ''Authority'' entry for parts 191 and 192 to include a citation to a provision of the Mineral Leasing Act (MLA), specifically, 30 U.S.C. 185(w)(3). Section 185(w)(3) provides that ''[p]eriodically, but at least once a year, the Secretary of the Department of Transportation shall cause the examination of all pipelines and associated facilities on Federal lands and shall cause the prompt reporting of any potential leaks or safety problems.'' The Secretary has delegated this responsibility to PHMSA (49 CFR 1.97). PHMSA has traditionally complied with § 185(w)(3) through the issuance of its pipeline safety regulations, which require annual examinations and prompt reporting for all or most of the pipelines they cover. PHMSA is making this change to be consistent with and make clear its long-standing position that the agency complies with the MLA through the issuance of pipeline safety regulations.

B. Executive Orders 12866 and 13771, and DOT Regulatory Policies and Procedures

Executive Order 12866 requires agencies to regulate in the ''most cost-effective manner,'' to make a ''reasoned determination that the benefits of the intended regulation justify its costs,'' and to develop regulations that ''impose the least burden on society.'' This action has been determined to be significant under Executive Order 12866. It is also considered significant under the Regulatory Policies and Procedures of the Department of Transportation because of substantial congressional, State, industry, and public interest in pipeline safety. The final rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866 (Regulatory Planning and Review) and is consistent with the Executive Order 12866 requirements and 49 U.S.C. 60102(b)(5)–(6). Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.,* the Office of Information and Regulatory Affairs designated this rule as not a ''major rule,'' as defined by 5 U.S.C. 804(2). This final rule is considered an Executive Order 13771 regulatory action. Details on the estimated costs of this final rule can be found in the rule's RIA.

The table below summarizes the annualized costs for the provisions in the final rule. These estimates reflect the timing of the compliance actions taken by operators and are annualized, where applicable, over 21 years and discounted to 2017 using rates of 3 percent and 7 percent. PHMSA estimates incremental costs for the final requirements in Section 5 of the RIA. PHMSA finds that the other final rule requirements will not result in an incremental cost. Additionally, PHMSA did not quantify the cost savings from the material properties verification provisions under this final rule compared to the existing regulations. The costs of this final rule reflect incremental integrity assessments, MAOP reconfirmation actions, and ILI launcher and receiver upgrades; PHMSA estimates the annualized cost of this rule is $32.7 million at a 7 percent discount rate.

SUMMARY OF ANNUALIZED COSTS, 2019–2039

[$2017 thousands]

Provision	Annualized cost	
	3% Discount rate	7% Discount rate
1. MAOP Reconfirmation & Material Properties Verification	$25.9	$27.9
2. Seismicity	0	0
3. Six-Month Grace Period for Seven Calendar-Year Reassessment Intervals	0	0
4. In-Line Inspection Launcher/Receiver Safety	0.03	0.04
5. MAOP Exceedance Reports	0	0
6. Strengthening Requirements for Assessment Methods	0	0
7. Assessments Outside HCAs	5.48	4.71
8. Related Records Provisions	0	0
Total	31.4	32.7

The benefits of the final rule will depend on the degree to which compliance actions result in additional safety measures, relative to the current baseline, and the effectiveness of these measures in preventing or mitigating future pipeline releases or other incidents. For the final rule RIA, PHMSA did not monetize benefits. The rule's benefits are discussed qualitatively instead.

For more information, please see the RIA in the docket for this rulemaking.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Flexibility Fairness Act of 1996, requires Federal regulatory agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the Administrative Procedure Act unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. PHMSA prepared a FRFA which is available in the docket for the rulemaking.

D. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this final rule per the principles and criteria in Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because this final rule would not significantly or uniquely affect the communities of the Indian tribal governments or impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

E. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. On April 18, 2016, PHMSA published an NPRM seeking public comments on the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines and gas gathering pipelines. During that time, PHMSA proposed changes to information collections that are no longer included in this final rule. PHMSA determined it would be more effective to advance a rulemaking that focuses on the mandates from the 2011 Pipeline Safety Act and split out the other provisions contained in the NPRM into two other separate rules. As such, PHMSA has removed all references to those collections previously contained in the NPRM and will submit information collection revision requests to OMB based on the requirements solely contained within this final rule.

PHMSA estimates that the proposals in this final rule will impact the information collections described below. These information collections are contained in the PSR, 49 CFR parts 190–199. The following information is provided for each information collection: (1) Title of the information collection, (2) OMB control number, (3) Current expiration date, (4) Type of request, (5) Abstract of the information collection activity, (6) Description of affected public, (7) Estimate of total annual reporting and recordkeeping burden, and (8) Frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. Title: Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 09/30/2021.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. Based on the proposed revisions in this rule, 25 new recordkeeping requirements are being added to the pipeline safety regulations for owners and operators of natural gas pipelines. Therefore, PHMSA expects to add 24,609 responses and 3,740 hours to this information collection because of the provisions in this final rule.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,861,470.

Total Annual Burden Hours: 1,674,810.

Frequency of Collection: On occasion.

2. Title: Notification Requirements for Gas Transmission Pipeline Operators.

OMB Control Number: New Collection. Will Request from OMB.

Current Expiration Date: TBD.

Abstract: A person owning or operating a natural gas pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request. Based on the proposed revisions in this rule, 10 new notification requirements are being added to the pipeline safety regulations for owners and operators of natural gas pipelines. Therefore, PHMSA expects to add 721 responses and 1,070 hours because of the notification requirements in this final rule.

Affected Public: Gas Transmission operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 721.

Total Annual Burden Hours: 1,070.

Frequency of Collection: On occasion.

3. Title: Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 8/31/2020.

Abstract: This information collection covers the collection of annual report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission and Gas Gathering Annual Report (form PHMSA F7 100.2–1) to collect additional information including mileage of pipe subject to the MAOP reconfirmation and MCA criteria. Based on the proposed revisions, PHMSA estimates that the Annual Report will take an additional 5 hours per report to complete to include the newly required data, increasing the burden for each report to 47 burden hours for an overall burden increase of 7,200 burden hours across all operators.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 10,852.

Total Annual Burden Hours: 83,151.

Frequency of Collection: On occasion.

4. Title: Incident for Natural Gas Pipeline Operators.

OMB Control Number: 2137–0635.

Current Expiration Date: 4/30/2022.

Abstract: This information collection covers the collection of incident report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission Incident Report to have operators indicate whether incidents occur inside Moderate Consequence Areas. PHMSA does not expect there to be an increase in burden for the reporting of Gas Transmission incident data.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 301.

Total Annual Burden Hours: 3,612.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, Telephone (202) 366–4595.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those

who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

Those desiring to comment on these information collections should send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503. Comments should be submitted on or prior to October 31, 2019. Comments may also be sent via email to the Office of Management and Budget at the following address: *oira_submissions@omb.eop.gov.* OMB is required to make a decision concerning the collection of information requirements contained in this final rule between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if received within 30 days of publication.

F. Unfunded Mandates Reform Act of 1995

An evaluation of Unfunded Mandates Reform Act (UMRA) considerations is performed as part of the Final Regulatory Impact Assessment. PHMSA determined that this final rule does not impose enforceable duties on State, local, or tribal governments or on the private sector of $100 million or more, adjusted for inflation, in any one year and therefore does not have implications under Section 202 of the UMRA of 1995. A copy of the RIA is available for review in the docket.

G. National Environmental Policy Act

PHMSA analyzed this final rule in accordance with the National Environmental Policy Act (42 U.S.C. 4332) and determined this action will not significantly affect the quality of the human environment. The Environmental Assessment for this final rule is in the docket.

H. Executive Order 13132: Federalism

PHMSA analyzed this final rule in accordance with Executive Order 13132 (''Federalism''). The final rule does not have a substantial direct effect on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. The pipeline safety laws, specifically 49 U.S.C. 60104(c), prohibits State safety regulation of interstate pipelines. Under the pipeline safety law, States have the ability to augment pipeline safety requirements for intrastate pipelines regulated by PHMSA, but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility PHMSA does not regulate. It is these statutory provisions, not the rule, that govern preemption of State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

I. Executive Order 13211

This final rule is not a ''significant energy action'' under Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use). It is not likely to have a significant adverse effect on supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this final rule as a significant energy action.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement, published on April 11, 2000 (65 FR 19476), in the **Federal Register** at: *https://www.govinfo.gov/content/FR-2000-04-11/pdf/00-8505.pdf.*

K. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN number contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

List of Subjects

49 CFR Part 191

MAOP exceedance, Pipeline reporting requirements.

49 CFR Part 192

Incorporation by reference, Integrity assessments, Material properties verification, MAOP reconfirmation, Pipeline safety, Predicted failure pressure, Recordkeeping, Risk assessment, Safety devices.

In consideration of the foregoing, PHMSA is amending 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 is revised to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et. seq.,* and 49 CFR 1.97.

■ 2. In § 191.23, paragraph (a)(6) is revised, paragraph (a)(10) is added, and paragraph (b)(4) is revised to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) * * *

(6) Any malfunction or operating error that causes the pressure—plus the margin (build-up) allowed for operation of pressure limiting or control devices—to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG.

* * * * *

(10) For transmission pipelines only, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of §§ 192.201, 192.620(e), and 192.739. The reporting requirement of this paragraph (a)(10) is not applicable to gathering lines, distribution lines, LNG facilities, or underground natural gas storage facilities (*See* paragraph (a)(6) of this section).

(b) * * *

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report. Notwithstanding this exception, a report must be filed for:

(i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and

(ii) Any condition under paragraph (a)(10) of this section.

* * * * *

■ 3. Section 191.25 is revised to read as follows:

§ 191.25 Filing safety-related condition reports.

(a) Each report of a safety-related condition under § 191.23(a)(1) through (9) must be filed (received by the Associate Administrator) in writing

within 5 working days (not including Saturday, Sunday, or Federal holidays) after the day a representative of an operator first determines that the condition exists, but not later than 10 working days after the day a representative of an operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reporting methods and report requirements are described in paragraph (c) of this section.

(b) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in § 191.23(a)(10) for a gas transmission pipeline must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance using the reporting methods and report requirements described in paragraph (c) of this section.

(c) Reports must be filed by email to *InformationResourcesManager@dot.gov* or by facsimile to (202) 366–7128. For a report made pursuant to § 191.23(a)(1) through (9), the report must be headed ''Safety-Related Condition Report.'' For a report made pursuant to § 191.23(a)(10), the report must be headed ''Maximum Allowable Operating Pressure Exceedances.'' All reports must provide the following information:

(1) Name, principal address, and operator identification number (OPID) of the operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 4. The authority citation for part 192 is revised to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et. seq.,* and 49 CFR 1.97.

■ 5. In § 192.3, the definitions for ''Engineering critical assessment (ECA)'' and ''Moderate consequence area'' are added in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Engineering critical assessment (ECA) means a documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.

* * * * *

Moderate consequence area means:

(1) An onshore area that is within a potential impact circle, as defined in § 192.903, containing either:

(i) Five or more buildings intended for human occupancy; or

(ii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1* (see: *https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf*), and that does not meet the definition of high consequence area, as defined in § 192.903.

(2) The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either 5 or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

* * * * *

■ 6. In § 192.5, paragraph (d) is added to read as follows:

§ 192.5 Class locations.

* * * * *

(d) An operator must have records that document the current class location of each pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.

■ 7. Amend § 192.7 as follows:
■ a. Revise paragraph (a)(1)(ii);
■ b. Add paragraph (b)(12);
■ c. Revise paragraphs (c)(2) and (4);
■ d. Re-designate paragraphs (d) through (j) as paragraphs (e) through (k), respectively;
■ e. Add new paragraphs (d) and (h)(2); and
■ f. Revise newly redesignated paragraph (j)(1).

The revisions and additions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

(a) * * *

(1) * * *

(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fedreg.legal@nara.gov* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.*

(b) * * *

(12) API STANDARD 1163, ''In-Line Inspection Systems Qualification,'' Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for § 192.493.

(c) * * *

(2) ASME/ANSI B16.5–2003, ''Pipe Flanges and Flanged Fittings,'' October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a), 192.279, and 192.607(f).

* * * * *

(4) ASME/ANSI B31G–1991 (Reaffirmed 2004), ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' 2004, (ASME/ANSI B31G), IBR approved for §§ 192.485(c), 192.632(a), 192.712(b), and 192.933(a).

* * * * *

(d) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone: 800–222–2768, website: *https://www.asnt.org/.*

(1) ANSI/ASNT ILI–PQ–2005(2010), ''In-line Inspection Personnel Qualification and Certification,'' Reapproved October 11, 2010, (ANSI/ASNT ILI–PQ), IBR approved for § 192.493.

(2) [Reserved]

* * * * *

(h) * * *

(2) NACE Standard Practice 0102–2010, ''In-Line Inspection of Pipelines,'' Revised 2010–03–13, (NACE SP0102), IBR approved for §§ 192.150(a) and 192.493.

* * * * *

(j) * * *

(1) AGA, Pipeline Research Committee Project, PR–3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' (December 22, 1989), (PRCI PR–3–805 (R–STRENG)), IBR approved for §§ 192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d).

* * * * *

■ 8. In § 192.9, paragraphs (b), (c), and (d)(1), (2), and (6) are revised to read as follows:

§ 192.9 What requirements apply to gathering lines?

* * * * *

(b) Offshore lines. An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, and in subpart O of this part. However, operators of Type A regulated onshore gathering lines in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) * * *

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines except the requirements in §§ 192.67, 192.127, 192.205, 192.227(c), 192.285(e), and 192.506;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except the requirements in § 192.493;

* * * * *

(6) Establish the MAOP of the line under § 192.619(a), (b), and (c);

* * * * *

■ 9. Section 192.18 is added to read as follows:

§ 192.18 How to notify PHMSA.

(a) An operator must provide any notification required by this part by—

(1) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov;* or

(2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave. SE, Washington, DC 20590.

(b) An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate applicable pipeline segment is regulated by that State.

(c) Unless otherwise specified, if the notification is made pursuant to § 192.506(b), § 192.607(e)(4), § 192.607(e)(5), § 192.624(c)(2)(iii), § 192.624(c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv), § 192.712(e)(2)(i)(E), § 192.921(a)(7), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, sampling approach, or technique (*i.e.,* ''other technology'') that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

§ 192.67 [Redesignated as § 192.69]

■ 10. Redesignate § 192.67 as § 192.69.

■ 11. Section 192.67 is added to read as follows:

§ 192.67 Records: Material properties.

(a) For steel transmission pipelines installed after [July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §§ 192.53 and 192.55. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

(b) For steel transmission pipelines installed on or before July 1, 2020], if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§ 192.53 and 192.55, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020], if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 12. Section 192.127 is added to read as follows:

§ 192.127 Records: Pipe design.

(a) For steel transmission pipelines installed after July 1, 2020], an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with § 192.103 and documenting that the determination of design pressure for the pipe is made in accordance with § 192.105.

(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting pipe design and the determination of design pressure in accordance with §§ 192.103 and 192.105, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 13. In § 192.150, paragraph (a) is revised to read as follows:

§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line, must

be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, *see* § 192.7).

* * * * *

■ 14. Section 192.205 is added to read as follows:

§ 192.205 Records: Pipeline components.

(a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.

(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 15. In § 192.227, paragraph (c) is added to read as follows:

§ 192.227 Qualification of welders.

* * * * *

(c) For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

■ 16. In § 192.285, paragraph (e) is added to read as follows:

§ 192.285 Plastic pipe: Qualifying persons to make joints.

* * * * *

(e) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

■ 17. Section 192.493 is added to read as follows:

§ 192.493 In-line inspection of pipelines.

When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI–PQ, and NACE SP0102, (incorporated by reference, *see* § 192.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

■ 18. Section 192.506 is added to read as follows:

§ 192.506 Transmission lines: Spike hydrostatic pressure test.

(a) *Spike test requirements.* Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this section.

(1) The test must use water as the test medium.

(2) The baseline test pressure must be as specified in the applicable paragraphs of § 192.619(a)(2) or § 192.620(a)(2), whichever applies.

(3) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505.

(4) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.

(b) *Other technology or other technical evaluation process.* Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with § 192.18 and must include the following information:

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

(2) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;

(3) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;

(4) Assessment techniques and acceptance criteria;

(5) Remediation methods for assessment findings;

(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;

(7) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and

(8) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

■ 19. In § 192.517, paragraph (a) introductory text is revised to read as follows:

§ 192.517 Records: Tests.

(a) An operator must make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505, 192.506, and 192.507. The record must contain at least the following information:

* * * * *

■ 20. Section 192.607 is added to read as follows:

§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

(a) *Applicability.* Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.

(b) *Documentation of material properties and attributes.* Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (*e.g.,* yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the pipeline.

(c) *Verification of material properties and attributes.* If an operator does not have traceable, verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:

(1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.

(2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.

(3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.

(4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.

(5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.

(d) *Special requirements for nondestructive Methods.* Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:

(1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;

(2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and

(3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

(e) *Sampling multiple segments of pipe.* To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:

(1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.

(2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to § 192.614, until completion of the lesser of the following:

(i) One excavation per mile rounded up to the nearest whole number; or

(ii) 150 excavations if the population is more than 150 miles.

(3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).

(4) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with § 192.18.

(5) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (e)(2) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.

(f) *Components.* For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference, *see* § 192.7)),

(1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.

(2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:

(i) Larger than 2 inches in nominal outside diameter,

(ii) Material grades of 42,000 psi (Grade X–42) or greater, or

(iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

(g) *Uprating.* The material properties determined from the destructive or nondestructive tests required by this

section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with § 192.107(b)(2).

■ 21. In § 192.619, the introductory text of paragraphs (a) introductory text and (a)(2) and (4) are revised and paragraphs (e) and (f) are added to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:

* * * * *

(2) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 psi (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the Table 1 to paragraph (a)(2)(ii):

TABLE 1 TO PARAGRAPH (a)(2)(ii)

Class location	Installed before (Nov. 12, 1970)	Factors,[1] segment—		
		Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1] For offshore pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

* * * * *

(4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with § 192.607, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure.

* * * * *

(e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624.

(f) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (a) through (e) of this section as follows:

(1) Operators of pipelines in operation as of [July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline;

(2) Operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with § 192.624, must retain the records reconfirming MAOP for the life of the pipeline; and

(3) Operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline.

■ 22. Section 192.624 is added to read as follows:

§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

(a) *Applicability.* Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:

(1) Records necessary to establish the MAOP in accordance with § 192.619(a), including records required by § 192.517(a), are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:

(i) A high consequence area as defined in § 192.903; or

(ii) A Class 3 or Class 4 location.

(2) The pipeline segment's MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment is located in one of the following areas:

(i) A high consequence area as defined in § 192.903;

(ii) A Class 3 or Class 4 location; or

(iii) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.

(b) *Procedures and completion dates.* Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:

(1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.

(2) Operators must complete all actions required by this section on 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) (*e.g.,* due to a location becoming a high consequence area), whichever is later.

(3) If operational and environmental constraints limit an operator from meeting the deadlines in § 192.624, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with § 192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and

any needed temporary measures needed to mitigate the impact on safety.

(c) *Maximum allowable operating pressure determination.* Operators of a pipeline segment meeting a condition in paragraph (a) of this section must reconfirm its MAOP using one of the following methods:

(1) *Method 1: Pressure test.* Perform a pressure test and verify material properties records in accordance with § 192.607 and the following requirements:

(i) *Pressure test.* Perform a pressure test in accordance with subpart J of this part. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii).

(ii) *Material properties records.* Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).

(iii) *Material properties verification.* If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with § 192.607. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with § 192.607.

(2) *Method 2: Pressure Reduction.* Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (*i.e.,* the location-specific operating pressure at each location).

(i) Where the pipeline segment has had a class location change in accordance with § 192.611, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:

(A) For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.

(B) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 2.00.

(ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.

(iii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with § 192.18 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with § 192.712;

(C) Justification that establishing MAOP by another method allowed by this section is impractical;

(D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance § 192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and

(E) Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.

(3) *Method 3: Engineering Critical Assessment (ECA).* Conduct an ECA in accordance with § 192.632.

(4) *Method 4: Pipe Replacement.* Replace the pipeline segment in accordance with this part.

(5) *Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius.* Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:

(i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (*i.e.,* the location specific operating pressure at each location);

(ii) Conduct patrols in accordance with § 192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with § 192.706 at intervals not to exceed those in the following table 1 to § 192.624(c)(5)(ii):

TABLE 1 TO § 192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	3½ months, but at least four times each calendar year	3½ months, but at least four times each calendar year.
(B) Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year.

(iii) Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.

(6) *Method 6: Alternative Technology.* Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with § 192.18. The notification must include descriptions of the following details:

(i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

(iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

(iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;

(v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.712;

(vi) Operational monitoring procedures;

(vii) Methodology and criteria used to justify and establish the MAOP; and

(vii) Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.

(d) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

■ 23. Section 192.632 is added to read as follows:

§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines.

When an operator conducts an MAOP reconfirmation in accordance with § 192.624(c)(3) ''Method 3'' using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: Threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

(a) *ECA Analysis.* (1) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with § 192.607. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §§ 192.617, 192.710, and subpart O of this part.

(2) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:

(i) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with § 192.712.

(ii) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference, *see* § 192.7) or R–STRENG (incorporated by reference, *see* § 192.7) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).

(iii) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.

(iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using § 192.607.

(3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

(4) The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii).

(b) *Assessment to determine defects remaining in the pipe.* An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph (a) of this section.

(1) An operator may use a previous pressure test that complied with subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of subpart J of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in

accordance with § 192.712. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in § 192.712.

(2) Operators may use an inline inspection program in accordance with paragraph (c) of this section.

(3) Operators may use ''other technology'' if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use ''other technology'' in the ECA, it must notify PHMSA in advance of using the other technology in accordance with § 192.18. The ''other technology'' notification must have:

(i) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.

(c) *In-line inspection.* An inline inspection (ILI) program to determine the defects remaining the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.

(1) If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.

(2) If the pipeline has had a reportable incident, as defined in § 191.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.

(3) Inline inspection must be performed in accordance with § 192.493.

(4) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.

(5) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O of this part, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.

(6) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§ 192.713 and 192.933.

(d) *Defect remaining life.* If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712.

(e) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

■ 24. Section 192.710 is added to read as follows:

§ 192.710 Transmission lines: Assessments outside of high consequence areas.

(a) *Applicability:* This section applies to onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30% of the specified minimum yield strength and are located in:

(1) A Class 3 or Class 4 location; or

(2) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (*i.e.,* ''smart pig'').

(3) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.

(b) *General*—(1) *Initial assessment.* An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of § 192.710(a) (*e.g.,* due to a change in class location or the area becomes a moderate consequence area), whichever is later.

(2) *Periodic reassessment.* An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.

(3) *Prior assessment.* An operator may use a prior assessment conducted before July 1, 2020 as an initial assessment for the pipeline segment, if the assessment met the subpart O requirements of part 192 for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(2) of this section calculated from the date of the prior assessment.

(4) *MAOP verification.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) for establishing MAOP may be used as an initial assessment or reassessment under this section.

(c) *Assessment method.* The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:

(1) *Internal inspection.* Internal inspection tool or tools capable of detecting those threats to which the

pipeline is susceptible, such as corrosion, deformation and mechanical damage (*e.g.,* dents, gouges and grooves), material cracking and crack-like defects (*e.g.,* stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;

(2) *Pressure test.* Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;

(3) *Spike hydrostatic pressure test.* A spike hydrostatic pressure test conducted in accordance with § 192.506. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) *Direct examination.* Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) *Guided Wave Ultrasonic Testing.* Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;

(6) *Direct assessment.* Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or

(7) *Other technology.* Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.

(d) *Data analysis.* An operator must analyze and account for the data obtained from an assessment performed under paragraph (c) of this section to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (*e.g.,* tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

(e) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that 180 days is impracticable.

(f) *Remediation.* An operator must comply with the requirements in §§ 192.485, 192.711, and 192.713, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

(g) *Analysis of information.* An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.

■ 25. Section 192.712 is added to read as follows:

§ 192.712 Analysis of predicted failure pressure.

(a) *Applicability.* Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.

(b) *Corrosion metal loss.* When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R–STRENG (incorporated by reference, *see* § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(c) [Reserved]

(d) *Cracks and crack-like defects*—(1) *Crack analysis models.* When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).

(2) *Analysis for crack growth and remaining life.* If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.

(i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.

(ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).

(iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment

methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(3) *Cracks that survive pressure testing.* For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

(i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in § 192.607;

(iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or

(iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.

(e) *Data.* In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.

(1) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements.

(2) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator shall use conservative assumptions as follows:

(i) *Material toughness.* An operator must use one of the following for material toughness:

(A) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(B) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607;

(C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;

(D) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or

(E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.

(ii) *Material strength.* An operator must assume one of the following for material strength:

(A) Grade A pipe (30,000 psi), or

(B) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.

(iii) *Pipe dimensions and other data.* Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 192.607, the operator must use values upon which the current MAOP is based.

(f) *Review.* Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.

(g) *Records.* An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:

(1) The technical approach used for the analysis;

(2) All data used and analyzed;

(3) Pipe and weld properties;

(4) Procedures used;

(5) Evaluation methodology used;

(6) Models used;

(7) Direct in situ examination data;

(8) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;

(9) Pressure test data and results;

(10) In-the-ditch assessments;

(11) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

(12) All finite element analysis results;

(13) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;

(14) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;

(15) Safety factors used for fatigue life and/or predicted failure pressure calculations;

(16) Reassessment time interval and safety factors;

(17) The date of the review;

(18) Confirmation of the results by qualified technical subject matter experts; and

(19) Approval by responsible operator management personnel.

■ 26. Section 192.750 is added to read as follows:

§ 192.750 Launcher and receiver safety.

Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (*e.g.* inspection tools, scrapers, or spheres), if pressure has not been relieved.

■ 27. In § 192.805, paragraph (i) is revised to read as follows:

§ 192.805 Qualification Program.

* * * * *

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if an operator significantly modifies the program after the administrator or state agency has verified that it complies

with this section. Notifications to PHMSA must be submitted in accordance with § 192.18.

■ 28. In § 192.909, paragraph (b) is revised to read as follows:

§ 192.909 How can an operator change its integrity management program?

* * * * *

(b) *Notification.* An operator must notify OPS, in accordance with § 192.18, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide notification within 30 days after adopting this type of change into its program.

■ 29. In § 192.917, paragraphs (a)(3) and (e)(2) through (4) are revised, and paragraph (e)(6) is added to read as follows:

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) * * *

(3) Time independent threats such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and

* * * * *

(e) * * *

(2) *Cyclic fatigue.* An operator must analyze and account for whether cyclic fatigue or other loading conditions (including ground movement, and suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The analysis must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the analysis together with the criteria used to determine the significance of the threat(s) to the covered segment to prioritize the integrity baseline assessment or reassessment. Failure stress pressure and crack growth analysis of cracks and crack-like defects must be conducted in accordance with § 192.712. An operator must monitor operating pressure cycles and periodically, but at least every 7 calendar years, with intervals not to exceed 90 months, determine if the cyclic fatigue analysis remains valid or if the cyclic fatigue analysis must be revised based on changes to operating pressure cycles or other loading conditions.

(3) *Manufacturing and construction defects.* An operator must analyze the covered segment to determine and account for the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must account for the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP, and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment.

(i) The pipeline segment has experienced a reportable incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, or a construction-, installation-, or fabrication-related defect;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *Electric Resistance Welded (ERW) pipe.* If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding 5 years (including abnormal operation as defined in § 192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.712.

* * * * *

(6) *Cracks.* If an operator identifies any crack or crack-like defect (*e.g.,* stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment that could adversely affect the integrity of the pipeline, the operator must evaluate, and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar characteristics associated with the crack or crack-like defect. Similar characteristics may include operating and maintenance histories, material properties, and environmental characteristics. An operator must establish a schedule for evaluating, and remediating, as necessary, the similar pipeline segments that is consistent with the operator's established operating and maintenance procedures under this part for testing and repair.

■ 30. In § 192.921, revise paragraph (a) and add paragraph (i) to read as follows:

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917).

(1) Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible. The use of internal inspection tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (*e.g.,* stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. In addition, an operator must analyze and account for uncertainties in reported results (*e.g.,* tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool

performance) in identifying and characterizing anomalies;

(2) Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) to justify an extended reassessment interval in accordance with § 192.939.

(3) Spike hydrostatic pressure test conducted in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and the pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.

* * * * *

(i) *Baseline assessments for pipeline segments with a reconfirmed MAOP.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a baseline assessment under this section.

■ 31. In § 192.933, paragraphs (a)(1) and (2) are revised to read as follows:

§ 192.933 What actions must be taken to address integrity issues?

(a) * * *

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R–STRENG (incorporated by reference, *see* § 192.7); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, an operator must notify PHMSA under § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

* * * * *

■ 32. In § 192.935, paragraph (b)(2) is revised to read as follows:

§ 192.935 What additional preventive and mitigative measures must an operator take?

* * * * *

(b) * * *

(2) *Outside force damage.* If an operator determines that outside force (*e.g.,* earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include increasing the frequency of aerial, foot or other methods of patrols; adding external protection; reducing external stress; relocating the line; or inline inspections with geospatial and deformation tools.

* * * * *

■ 33. In § 192.937, revise paragraph (c) and add paragraph (d) to read as follows:

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

* * * * *

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified on the covered segment (*see* § 192.917).

(1) *Internal inspection tools.* When performing an assessment using an in-line inspection tool, an operator must comply with the following requirements:

(i) Perform the in-line inspection in accordance with § 192.493;

(ii) Select a tool or combination of tools capable of detecting the threats to which the pipeline segment is susceptible such as corrosion, deformation and mechanical damage (*e.g.* dents, gouges and grooves), material cracking and crack-like defects (*e.g.* stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible; and

(iii) Analyze and account for uncertainties in reported results (*e.g.,* tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

(2) *Pressure test conducted in accordance with subpart J of this part.* The use of pressure testing is appropriate for threats such as: Internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test

pressures specified in table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) to justify an extended reassessment interval in accordance with § 192.939.

(3) *Spike hydrostatic pressure test in accordance with § 192.506.* The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as: Stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, or magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927, and 192.929;

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18; or

(8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than 7 calendar years. An operator using this reassessment method must comply with § 192.931.

(d) *MAOP reconfirmation assessments.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a reassessment under this section.

■ 34. In § 192.939, paragraphs (a) introductory text, (b) introductory text, and (b)(1) are revised to read as follows:

§ 192.939 What are the required reassessment intervals?

* * * * *

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS, in accordance with § 192.18, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than 7 calendar years, the operator must, within the 7-calendar-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

* * * * *

(b) *Pipelines Operating below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS in accordance with § 192.18. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following—

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than 7 calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low stress reassessment in accordance with § 192.941.

* * * * *

§ 192.949 [Removed and Reserved]

■ 35. Remove and reserve § 192.949.

■ 36. Appendix F is added to read as follows:

Appendix F to Part 192–Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

This appendix defines criteria which must be properly implemented for use of guided wave ultrasonic testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered ''other technology'' as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified 90 days prior to use in accordance with §§ 192.921(a)(7) or 192.937(c)(7). GWUT in the ''Go-No Go'' mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested, or replaced prior to completing the integrity assessment on the carrier pipe.

I. *Equipment and Software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Computer software for the inspection equipment must be reviewed and updated, as required, on an annual basis, with intervals not to exceed 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.

II. *Inspection Range.* The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general, the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

III. *Complete Pipe Inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is

inspected. This may require multiple GWUT shots. Double-ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. *Sensitivity.* The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross sectional area (CSA).

The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

All defect indications in the ''Go-No Go'' mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. *Wave Frequency.* Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. *Signal or Wave Type: Torsional and Longitudinal.* Both torsional and longitudinal waves must be used and use must be documented.

VII. *Distance Amplitude Correction (DAC) Curve and Weld Calibration.* The distance amplitude correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross-sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

VIII. *Dead Zone.* The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. *Near Field Effects.* The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. *Coating Type.* Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the pipe, then another type of assessment method must be utilized.

XI. *End Seal.* When assessing cased carrier pipe with GWUT, operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. *Weld Calibration to set DAC Curve.* Accessible welds, along or outside the pipeline segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipeline segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by a documented engineering analysis and evaluation.

XIII. *Validation of Operator Training.* Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

A. Equipment operation,

B. field data collection, and

C. data interpretation on cased and buried pipe.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment. A senior-level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior-level GWUT equipment operator must have additional training and experience, including training specific to cased and buried pipe, with a quality control program which that conforms to Section 12 of ASME B31.8S (for availability, see § 192.7).

XIV. *Training and Experience Minimums for Senior Level GWUT Equipment Operators:*

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XV. *Equipment: Traceable from vendor to inspection company.* An operator must maintain documentation of the version of the GWUT software used and the serial number of the other

equipment such as collars, cables, etc., in the report.

XVI. *Calibration Onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated to a different casing or pipeline segment. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVII. *Use on Shorted Casings (direct or electrolytic).* GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (*see § 192.605*) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures.

XVIII. *Direct examination of all indications above the detection sensitivity threshold.* The use of GWUT in the ''Go-No Go'' mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe or other GWUT application. If this cannot be accomplished, then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XIV. *Timing of direct examination of all indications above the detection sensitivity threshold.* Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

REQUIRED RESPONSE TO GWUT INDICATIONS

GWUT criterion	Operating pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50% SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 5% CSA).	Replace or direct examination within 12 months, and instrumented leak survey once every 30 calendar days.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and maintain MAOP below the operating pressure at time of discovery.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.

Issued in Washington, DC, on September 16, 2019, under authority delegated in 49 CFR part 1.97.

Howard R. Elliott,

Administrator.

[FR Doc. 2019–20306 Filed 9–30–19; 8:45 am]

BILLING CODE 4910–60–P

SMALL BUSINESS ADMINISTRATION

National Small Business Development Center Advisory Board

AGENCY: Small Business Administration.

ACTION: Notice of open Federal Advisory Committee meeting.

SUMMARY: The SBA is issuing this notice to announce the date, time and agenda for a meeting of the National Small Business Development Center Advisory Board. The meeting will be open to the public; however, advance notice of attendance is required.

DATES: Wednesday, July 28, 2021 at 2:00 p.m. EDT.

ADDRESSES: Meeting will be held via Microsoft Teams.

FOR FURTHER INFORMATION CONTACT: Rachel Karton, Office of Small Business Development Centers, U.S. Small Business Administration, 409 Third Street SW, Washington, DC 20416; *Rachel.newman-karton@sba.gov;* 202–619–1816.

If anyone wishes to be a listening participant or would like to request accommodations, please contact Rachel Karton at the information above.

SUPPLEMENTARY INFORMATION: Pursuant to section 10(a) of the Federal Advisory Committee Act (5 U.S.C. Appendix 2), the SBA announces the meetings of the National SBDC Advisory Board. This Board provides advice and counsel to the SBA Administrator and Associate Administrator for Small Business Development Centers.

Purpose

The purpose of the meeting is to discuss the following issues pertaining to the SBDC Program:

- Cybersecurity
- Outreach to underserved communities
- Strategies for getting Small Business back to normal

Andrienne Johnson,

Committee Management Officer.

[FR Doc. 2021–12222 Filed 6–9–21; 8:45 am]

BILLING CODE P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2021–0050]

Pipeline Safety: Statutory Mandate To Update Inspection and Maintenance Plans To Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas From Pipeline Facilities

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Notice; issuance of advisory bulletin.

SUMMARY: PHMSA is issuing this advisory bulletin to remind each owner and operator of a pipeline facility that the ''Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020'' (PIPES Act of 2020) contains a self-executing mandate requiring operators to update their inspection and maintenance plans to address eliminating hazardous leaks and minimizing releases of natural gas (including intentional venting during normal operations) from their pipeline facilities. Operators must also revise their plans to address the replacement or remediation of pipeline facilities that are known to leak based on their material, design, or past operating and maintenance history. The statute requires pipeline operators to complete these updates by December 27, 2021.

FOR FURTHER INFORMATION CONTACT: Sayler Palabrica, by phone at 202–366–0559 or by email at *Sayler.Palabrica@dot.gov.*

SUPPLEMENTARY INFORMATION: Natural gas is composed primarily of methane, therefore leaks and other releases of natural gas emit methane gas into the atmosphere. According to the U.S. Environmental Protection Agency (EPA), methane is a potent greenhouse gas with a global warming potential (GWP) of 28–36 over 100 years.[1] Compared to carbon dioxide, methane gas has a stronger warming effect, but a shorter lifespan in the atmosphere. Due to the high GWP and short lifespan of methane gas in the atmosphere, minimizing releases of natural gas (both fugitive and vented emissions) has relatively near-term benefits to mitigating the consequences of climate change. Likewise, remediation or replacement of pipeline facilities that are known to leak based on material, design or past operating and maintenance history can result in enhanced public safety, environmental protection, and economic benefits.

The ''Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020'' (Pub. L. 116–260, Division R; ''PIPES Act of 2020'') was signed into law on December 27, 2020. This law contains several provisions that specifically address the elimination of hazardous leaks and minimization of releases of natural gas from pipeline facilities. Section 114(b) of the PIPES Act of 2020 contains self-executing provisions that apply directly to pipeline operators. This section requires each pipeline operator to update its inspection and maintenance plan required under 49 U.S.C. 60108(a) no later than one year after the date of enactment of the PIPES Act of 2020 (*i.e.,* by December 27, 2021) to address the elimination of hazardous leaks and minimization of releases of natural gas (including, and not limited to, intentional venting during normal operations) from the operators' pipeline facilities (49 U.S.C. 60108(a)(2)(D)). The PIPES Act of 2020 also requires those plans to address the replacement or remediation of pipelines that are known to leak due to their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history (49 U.S.C. 60108(a)(2)(E)). In addition, 49 U.S.C. 60108(a)(2) requires that operators continue updating these plans to meet the requirements of any future regulations related to leak detection and repair that are promulgated under 49 U.S.C. 60102(q).

Advisory Bulletin (ADB–2021–01)

To: Owners and Operators of Gas and Hazardous Liquid Pipeline Facilities.

Subject: Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline Facilities.

Advisory: The PIPES Act of 2020 contains self-executing provisions requiring pipeline facility operators to update their inspection and maintenance plans to address the elimination of hazardous leaks and minimization of releases of natural gas (including, and not limited to, intentional venting during normal operations) from their systems before December 27, 2021. PHMSA expects that operators will comply with the inspection and maintenance plan revisions required in the PIPES Act of 2020 by revising their operations and

[1] ''Understanding Global Warming Potentials,'' U.S. EPA, available at *https://www.epa.gov/ghgemissions/understanding-global-warming-potentials.*

maintenance (O&M) plans required under 49 CFR 192.605, 193.2017, and 195.402, to address the elimination of hazardous leaks and minimize releases of natural gas from pipeline facilities. The plans must also address the replacement or remediation of pipelines that are known to leak due to their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past O&M history. The plans must in be in writing, tailored to the operator's pipeline facilities, supported by technical analysis where necessary, and sufficiently detailed to clearly describe the manner in which each requirement is met. For additional guidance on O&M plans for hazardous liquid and natural gas pipeline facilities, see ''Operations & Maintenance Enforcement Guidance,'' part 192 subparts L and M, page 17, available at *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/regulatory-compliance/pipeline/enforcement/5776/o-m-enforcement-guidance-part-192-7-21-2017.pdf;* and ''Operations & Maintenance Enforcement Guidance,'' part 195 subpart F, page 18, available at *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/regulatory-compliance/pipeline/enforcement/5781/o-m-enforcement-guidance-part-195-7-21-2017.pdf.*

Pursuant to 49 U.S.C. 60108(a)(3), as amended by section 114(a) of the PIPES Act of 2020, PHMSA and state authorities with a certification under 49 U.S.C. 60105 will inspect operators' revised O&M plans in calendar year 2022, and such inspections must be completed by December 27, 2022. During these inspections, PHMSA, or the relevant state authority, is required to evaluate whether the plans adequately address items listed in section 114 of the PIPES Act of 2020.

Operators need to consider the following items as they update their plans to comply with section 114 of the PIPES Act of 2020:

• O&M plans must be detailed to address the elimination of hazardous leaks and minimization of releases of natural gas from the operators' pipeline facilities; meaning pipeline operators must update their plans to minimize, among other things, fugitive emissions and vented emissions from pipeline facilities. PHMSA and state inspections, therefore, will evaluate the steps taken to prevent and mitigate both unintentional, fugitive emissions as well as intentional, vented emissions. Fugitive emissions include any unintentional leaks from equipment such as pipelines, flanges, valves, meter sets, or other equipment. Vented emissions include any release of natural gas to the atmosphere due to equipment design or operations and maintenance procedures. Common sources of vented emissions include pneumatic device bleeds, blowdowns, incomplete combustion, or overpressure protection venting (*e.g.,* relief valves).

• O&M plans must address the replacement or remediation of pipelines that are known to leak based on the material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history of the pipeline. PHMSA and state inspections will include an evaluation of how the material present in the pipeline system, design of the system, as well as the past O&M history of the system, contribute to the leaks that occur on the system. PHMSA and states will evaluate whether the plans adequately address reducing leaks on operators' pipeline systems due to the aforementioned factors.

• Operators must carry out a current, written O&M plan to address public safety and the protection of the environment. In addition to the new statutory requirement that PHMSA and state inspections consider the extent to which the plans will contribute to the elimination of hazardous leaks and minimizing releases of natural gas from pipeline facilities, PHMSA's inspections will continue to include an evaluation of the extent to which the plans contribute to both public safety and the protection of the environment.

Developing and implementing comprehensive written O&M plans is an effective way to eliminate hazardous leaks and minimize the release of natural gas from pipeline systems. PHMSA anticipates these self-executing statutory mandates will result in enhanced public safety and reductions in pipeline emissions thereby reducing impact on the environment.

Issued in Washington, DC, on June 4, 2021, under authority delegated in 49 CFR 1.97.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

[FR Doc. 2021–12155 Filed 6–9–21; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF THE TREASURY

Office of the Comptroller of the Currency

[Docket ID OCC–2021–0010]

Mutual Savings Association Advisory Committee

AGENCY: Department of the Treasury, Office of the Comptroller of the Currency (OCC).

ACTION: Notice of federal advisory committee meeting.

SUMMARY: The OCC announces a meeting of the Mutual Savings Association Advisory Committee (MSAAC).

DATES: A virtual public meeting of the MSAAC will be held on Tuesday, June 29, 2021, beginning at 9:00 a.m. Eastern Daylight Time (EDT).

ADDRESSES: The OCC will host the June 29, 2021 meeting of the MSAAC virtually.

FOR FURTHER INFORMATION CONTACT: Michael R. Brickman, Deputy Comptroller for Thrift Supervision, (202) 649–5420, Office of the Comptroller of the Currency, Washington, DC 20219. You also may access prior MSAAC meeting materials on the MSAAC page of the OCC's website at Mutual Savings Association Advisory Committee.

SUPPLEMENTARY INFORMATION: Under the authority of the Federal Advisory Committee Act, 5 U.S.C. App. 2, and the regulations implementing the Act at 41 CFR part 102–3, the OCC is announcing that the MSAAC will convene a virtual meeting on Tuesday, June 29, 2021. The meeting is open to the public and will begin at 9:00 a.m. EDT. The purpose of the meeting is for the MSAAC to advise the OCC on regulatory or other changes the OCC may make to ensure the health and viability of mutual savings associations. The agenda includes a discussion of current topics of interest to the industry.

Members of the public may submit written statements to the MSAAC. The OCC must receive written statements no later than 5:00 p.m. EDT on Thursday, June 24, 2021. Members of the public may submit written statements to *MSAAC@occ.treas.gov.*

Members of the public who plan to attend the virtual meeting should contact the OCC by 5:00 p.m. EDT on Thursday, June 24, 2021, to inform the OCC of their desire to attend the meeting and to obtain information about participating in the meeting. Members of the public may contact the OCC via email at *MSAAC@OCC.treas.gov* or by

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–2011–0023; Amdt. No. 192–132]

RIN 2137–AF39

Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. This final rule addresses several lessons learned following the Pacific Gas and Electric Company incident that occurred in San Bruno, CA, on September 9, 2010, and responds to public input received as part of the rulemaking process. The amendments in this final rule clarify certain integrity management provisions, codify a management of change process, update and bolster gas transmission pipeline corrosion control requirements, require operators to inspect pipelines following extreme weather events, strengthen integrity management assessment requirements, adjust the repair criteria for high-consequence areas, create new repair criteria for non-high consequence areas, and revise or create specific definitions related to the above amendments.

DATES: The final rule is effective May 24, 2023. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of May 24, 2023. The incorporation by reference of other publications listed in this rule was approved by the Director of the Federal Register on July 1, 2020.

FOR FURTHER INFORMATION CONTACT: Technical questions: Steve Nanney, Senior Technical Advisor, by telephone at 713–272–2855. General information: Robert Jagger, Senior Transportation Specialist, by telephone at 202–366–4361.

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I. Executive Summary

A. Purpose of the Regulatory Action

This final rule concludes a decade-long effort by PHMSA to amend its regulations governing onshore natural gas transmission pipelines in response to the tragic September 9, 2010, incident at a Pacific Gas and Electric Company (PG&E) gas transmission pipeline in San Bruno, CA, which resulted in the death of 8 people, injuries to more than 60 other people, and the destruction or damage of over 100 homes. PHMSA expects the new requirements in this final rule will reduce the frequency and consequences of failures and incidents from onshore natural gas transmission pipelines through earlier detection of threats to pipeline integrity, including those from corrosion or following extreme weather events. The safety enhancements in this final rule, therefore, are expected to improve public safety, reduce threats to the environment (including, but not limited to, reduction of greenhouse gas emissions released during natural gas pipeline incidents), and promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities that are located near interstate gas transmission pipelines.

Although the Federal Pipeline Safety Regulations (49 Code of Federal Regulations (CFR) parts 190 through 199; PSR) applicable to gas transmission and gathering pipeline systems set forth in parts 191 and 192 have increased the level of safety associated with the transportation of gas, serious safety incidents continue to occur on gas transmission and gathering pipeline systems, resulting in serious risks to life and property. In its investigation of the 2010 PG&E incident, the National Transportation Safety Board (NTSB) found among several causal factors that PG&E had an inadequate integrity management (IM) program that failed to detect and repair or remove a defective pipe section on its gas transmission line.[1] PG&E based its IM program on incomplete and inaccurate pipeline information, which led to, among other issues, faulty risk assessments, improper assessment method selections, and internal assessments of the program that were superficial and resulted in no meaningful improvement.[2]

Prior to the PG&E incident, PHMSA had initiated an advance notice of proposed rulemaking (ANPRM) to seek comment on whether the IM requirements in part 192 should be changed and whether other issues related to pipeline system integrity should be addressed by strengthening or expanding non-IM requirements.

[1] NTSB, NTSB/PAR–11–01, ''Pipeline Accident Report: Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010'' (2011) (NTSB Incident Report on San Bruno).

[2] NTSB Incident Report on San Bruno at 107–115.

PHMSA published the ANPRM on August 25, 2011.[3]

Based on the comments on the ANPRM, PHMSA published a notice of proposed rulemaking (NPRM) on April 8, 2016, to seek public comments on proposed changes to the PSR governing transmission and gathering lines.[4] A summary of those proposed changes pertaining to this rulemaking, corresponding stakeholder feedback, and PHMSA's responses to stakeholder feedback on the individual provisions, is provided below in section III of this document (Discussion of NPRM Comments, GPAC Recommendations, and PHMSA Response).

PHMSA determined that the most efficient way to manage the proposals in the NPRM was to divide them into three separate final rule actions. The first of these final rules was published on October 1, 2019, and addressed topics primarily relating to congressional mandates and safety recommendations, including maximum allowable operating pressure (MAOP) reconfirmation and material properties verification, the expansion of integrity assessments beyond high-consequence areas (HCA), the consideration of seismicity, in-line inspection (ILI) launcher and receiver safety, MAOP exceedance reporting, and strengthened requirements for assessment methods (2019 Gas Transmission Rule).[5] Provisions related to gas gathering pipelines were addressed in a separate rulemaking.[6] This rulemaking finalizes the remaining provisions from the NPRM as outlined below.

B. Summary of the Major Provisions of the Final Rule

To reduce the risks of pipeline incidents, PHMSA is amending the PSR applicable to gas transmission pipelines to improve the protection of the public, property, and the environment; close regulatory gaps; and adopt additional safety measures to improve safety inside and outside of HCAs. Specifically, PHMSA is making changes to clarify the IM requirements; improve the management of change (MOC) process; strengthen corrosion control requirements; provide parameters for inspections following extreme weather events; strengthen requirements related to the IM assessment methods; and improve the repair criteria for pipeline anomalies. PHMSA is also amending certain definitions in part 192 in support of these provisions.

PHMSA is modifying the IM regulations by adding specificity to the data integration language. The final rule establishes several pipeline attributes that must be included in an operator's risk analysis when an operator determines what threats are applicable to a pipeline segment. PHMSA is also explicitly requiring that operators integrate analyzed information into their IM programs and is requiring that data be verified and validated. Additionally, PHMSA is issuing requirements for applying knowledge gained through an operator's IM program, including provisions for analyzing interacting threats, potential failures, and worst-case incident scenarios from the initial failure to incident termination. Several of these items were proposed in response to NTSB findings following the PG&E incident that suggested pipeline operators were often not conducting data analysis, data integration, threat identification, and risk assessment in the manner originally intended and specified in subpart O of part 192.

Similarly, following the PG&E incident, PHMSA, informed by (inter alia) the NTSB's evaluation of the incident and ANPRM comments, determined that the existing MOC requirements and industry practices were not sufficient[7] and looked to align the regulatory requirements with the standards outlined in American Society of Mechanical Engineers/American National Standards Institute (ASME/ANSI) B31.8S.[8] Specifically, this final rule requires each operator of an onshore gas transmission pipeline to develop and follow a MOC process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary.

This final rule also improves and updates the corrosion control requirements for gas transmission pipeline operators. Based on lessons PHMSA has learned following several pipeline failures, and following PHMSA's workshop on pipeline construction in Fort Worth, TX, on April 23, 2009,[9] PHMSA determined that construction practices, including the installation of pipe in-ditch, can result in damaged coating that can compromise corrosion control. Therefore, this rule requires that operators perform assessments to identify suspected damage promptly after backfilling and then remediate any coating damage found. Further, PHMSA has noted that the existing regulations were not always effective at eliminating deficiencies in cathodic protection[10] corrosion control or at preventing incidents from internal corrosion. Therefore, this rule strengthens the requirements for internal and external corrosion controls related to monitoring requirements and surveys. PHMSA also determined that additional prescriptive preventive and mitigative (P&M) measures are needed for managing electrical interference currents.

Extreme weather has been a contributing factor in several pipeline failures. PHMSA issued Advisory Bulletins in 2015, 2016, and 2019 to communicate the potential for damage to pipeline facilities caused by severe flooding, including actions that operators should consider taking to ensure the integrity of pipelines in the event of flooding, river scour, river channel migration, and earth movement.[11] As PHMSA has noted in another series of Advisory Bulletins, hurricanes are also capable of causing extensive damage to both offshore and inland pipelines.[12]

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[3] ''Safety of Gas Transmission Pipelines,'' 76 FR 53086 (Aug. 25, 2011).

[4] ''Safety of Gas Transmission and Gathering Pipelines,'' 81 FR 20722 (Apr. 8, 2016).

[5] ''Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments,'' 84 FR 52180 (Oct. 1, 2019).

[6] ''Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulations of Large, High-Pressure Lines, and Other Related Amendments,'' 86 FR 63266 (Nov. 15, 2021) (Gas Gathering Final Rule).

[7] See 81 FR 20796; NTSB Incident Report on San Bruno at 95–97 (concluding that the probable cause of the PG&E incident was PG&E's inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, and noting that PG&E had poor quality control during a pipe installation project that later failed in 2008 in Rancho Cordova, CA).

[8] ASME/ANSI ''B31.8S–2004: Supplement to B31.8 on Managing System Integrity of Gas Pipelines'' (Jan. 14, 2005).

[9] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=58.*

[10] Cathodic protection is a technique used to control corrosion by making the metal pipe a cathode of an electrochemical cell. Essentially, the pipeline is connected to a more easily corroded metal that acts as an anode. That ''sacrificial anode'' metal corrodes instead of the metal that is being protected. For pipelines, passive galvanic cathodic protection is often not adequate, and an external direct current (DC) electrical power source is used to provide sufficient current.

[11] ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,'' 80 FR 19114 (Apr. 9, 2015); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,'' 81 FR 2943 (Jan. 19, 2016); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,'' 84 FR 18919 (May 2, 2019).

[12] ''Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Ivan,'' 69 FR 57135 (Sept. 23, 2004); ''Pipeline Safety Advisory: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Katrina,'' 70 FR 53272 (Sept. 7, 2005); ''Pipeline Safety: Potential for

Continued

Because of the frequency and severe consequences of these events,[13] operators must protect the public from pipeline risks in the event of a natural disaster or extreme weather. While many prudent operators might voluntarily perform inspections following such events, the potential risk to public safety and environment merits codification of those practices in regulatory requirements. Therefore, PHMSA is amending the PSR to require that operators commence inspection of their potentially affected facilities within 72 hours after the operator determines the affected area can be safely accessed following the cessation of an extreme weather event such as a hurricane, landslide, flood; a natural disaster, such as an earthquake; or another similar event that has the likelihood to damage infrastructure. If an operator finds an adverse condition during the inspection, the operator must take appropriate remedial action to ensure the safe operation of the pipeline.[14]

PHMSA is also strengthening the standards for performing pipeline assessments by incorporating by reference certain consensus standards for both stress corrosion cracking (NACE International Standard Practice 0204–2008, ''Stress Corrosion Cracking Direct Assessment Methodology'' (2008) (NACE 0204–2008)) and internal corrosion direct assessments (NACE International Standard Practice 0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas'' (2006) (NACE SP0206–2006)). Operators are already required to assess the condition of gas transmission pipelines in HCAs and certain non-HCAs periodically in accordance with §§ 192.710, 192.921, and 192.937. When the initial IM regulations creating subpart O were issued in 2003 (2003 IM rule), industry standards did not exist for these types of assessments.[15] By incorporating by reference the standards subsequently published by NACE International,[16] PHMSA is ensuring greater consistency, accuracy, and quality when operators perform these assessments.

This final rule also updates the existing repair criteria for HCAs by incorporating criteria for additional anomaly types such as crack anomalies, certain corrosion metal loss defects, and certain mechanical damage defects. Such revisions will provide greater assurance that operators will repair injurious anomalies and defects before those defects grow to a size that causes a leak or rupture. PHMSA also is finalizing explicit repair criteria for non-HCAs. Prior to this final rule, there were only general requirements in the regulations for operators to perform repairs in non-HCAs. The content of the non-HCA repair criteria being finalized in this rule is consistent with the criteria for HCAs; however, PHMSA has provided longer timeframes for the remediation of conditions that are not categorized as ''immediate'' conditions to provide operators the ability to prioritize remediating anomalous conditions in HCAs where consequences of a pipeline failure may be greater.

The various changes in this rule have also prompted additions and changes to certain definitions in part 192. PHMSA has created or made changes to the following terms: ''close interval survey,'' ''distribution center,'' ''dry gas or dry natural gas,'' ''hard spot,'' ''in-line inspection (ILI),'' ''in-line inspection tool or instrumented internal inspection device,'' ''transmission line,'' and ''wrinkle bend.''

C. Costs and Benefits

PHMSA has prepared an assessment of the benefits and costs of the final rule as well as reasonable alternatives. PHMSA estimates the annual costs of the rule to be approximately $17 million, calculated using a 7 percent discount rate. The costs reflect improvements made to the MOC process, additional corrosion control requirements, the provisions related to inspections following extreme weather events, and the changes made to the repair criteria. PHMSA finds that the other final rule requirements will not result in incremental costs.

PHMSA is posting the Regulatory Impact Analysis (RIA) for this rule in the public docket. PHMSA has determined that the regulatory amendments adopted in this final rule will improve public safety, reduce threats to the environment (including, but not limited to, reduction of methane emissions contributing to the climate crisis), and promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities. PHMSA finds the regulatory amendments adopted in this final rule are technically feasible, reasonable, cost-effective, and practicable because the public safety, environmental, and equity benefits of its regulatory amendments described herein and within its supporting documents (including the RIA and environmental assessment, each available in the docket for this rulemaking) will justify any associated costs and demonstrate and the superiority of the final rule compared to alternatives.

II. Background

A. Overview

On September 9, 2010, a 30-inch-diameter natural gas transmission pipeline, owned and operated by PG&E, ruptured in a residential neighborhood in San Bruno, CA. The rupture produced a crater approximately 72 feet long by 26 feet wide. The segment of pipe that ruptured weighed approximately 3,000 pounds, was 28 feet long, and was found 100 feet south of the crater. When the escaping gas ignited, the resulting fire killed 8 people, injured approximately 60 more, destroyed or damaged 108 homes, and caused the evacuation of over 300 people. In its pipeline accident report for the incident, the NTSB determined that the probable cause of the incident was PG&E's inadequate quality control and assurance when it relocated the line in 1956 and its inadequate IM program. The NTSB determined that PG&E's IM program was deficient and ineffective because it was based on incomplete and inaccurate pipeline information, did not consider how the pipeline's design and materials contributed to the risk of a pipeline failure, and failed to consider the presence of previously identified welded seam cracks as part of its risk assessment. These deficiencies resulted in the selection of an assessment method that could not detect welded seam defects and led to internal assessments of PG&E's IM program that were superficial and resulted in no improvements. Ultimately, this inadequate IM program failed to detect and repair or replace the defective pipe section.

Damage to Pipeline Facilities Caused by the Passage of Hurricanes,'' 76 FR 54531 (Sept. 1, 2011) (alerting operators to the potential for damage from Hurricane Ivan).

[13] For the impacts of climate change on precipitation; droughts, floods, and wildfire; and extreme storms, see U.S. Global Change Research Program, ''Climate Science Special Report: Fourth National Climate Assessment, Volume 1,'' at ch. 7–9 (2017).

[14] PHMSA notes that these part 192 amendments are consistent with similar provisions adopted for part 195 for hazardous liquid pipelines. See ''Pipeline Safety: Safety of Hazardous Liquid Pipelines,'' 84 FR 52260 (Oct. 1, 2019).

[15] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines): Final Rule,'' 68 FR 69778 (Dec. 15, 2003).

[16] In 2021, NACE International merged with the Society for Protective Coatings, becoming the Association for Materials Protection and Performance (AMPP). They will continue to be referred to as NACE International throughout this document.

In response to this incident, Congress, the NTSB, and the Government Accountability Office (GAO) called for PHMSA to improve IM and address other weaknesses and gaps in the PSR. As described in more detail in the sections that follow, this is the second of three planned rulemakings that are the culmination of this rulemaking initiative.

B. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM to seek public comments regarding potential revisions to the PSR pertaining to the safety of gas transmission and gathering pipelines. PHMSA requested comments on 122 questions spread across 15 broad issues involving IM and non-IM requirements. The issues related to IM requirements included whether the definition of an HCA should be revised and whether additional restrictions should be placed on the use of certain pipeline assessment methods. The issues related to non-IM requirements included whether revised requirements were needed for mainline valve spacing and actuation, whether requirements for corrosion control should be strengthened, and whether new regulations were needed to govern the safety of gas gathering lines and underground natural gas storage facilities. Based on the comments received on several of the ANPRM topics, PHMSA developed specific proposals for some of those topics in an NPRM that was the basis for this final rule.

C. Notice of Proposed Rulemaking and Subsequent Final Rule

On April 8, 2016, PHMSA published an NPRM seeking public comments on proposed revisions to the PSR pertaining to the safety of onshore gas transmission pipelines and gas gathering pipelines. PHMSA considered the comments it received from the ANPRM and proposed new pipeline safety requirements and revisions of existing requirements in several major topic areas. A summary of the NPRM proposals and topics pertinent to this rulemaking, the comments received on those specific proposals, and PHMSA's response to the comments received, is provided under section III (Discussion of NPRM Comments, GPAC Recommendations, and PHMSA Response).

On October 1, 2019, PHMSA promulgated a subset of the rules proposed in the NPRM by issuing the first of three planned final rules. In that rule, PHMSA addressed gas transmission pipelines and established minimum Federal safety standards for MAOP reconfirmation, pipeline physical material properties verification, the expansion of integrity assessments beyond HCAs, the consideration of seismicity in an operator's risk assessment and P&M measures, ILI tool launcher and receiver safety, MAOP exceedance reporting, and strengthened requirements for IM assessment methods.

This final rule, the second of three planned rules, finalizes several proposed amendments in the NPRM related to gas transmission pipelines, including provisions related addressing repair criteria, IM improvements, cathodic protection, MOC processes, and other related amendments. A separate rulemaking, dealing with the safety of onshore gas gathering pipelines, was the subject of a final rule published on November 15, 2021, and extended reporting and safety requirements to certain gathering pipelines that were formerly not subject to Federal safety oversight. PHMSA estimated in that Gas Gathering Final Rule that there were over 400,000 miles of gas gathering pipelines that were not subject to minimum Federal pipeline safety standards, including basic incident and mileage reporting. The Gas Gathering Final Rule extended annual and incident reporting requirements to all gathering pipelines and defined a new category of ''Type C'' gathering pipelines to address the safety of larger-diameter, higher-pressure onshore gathering pipelines that were formerly unregulated. The scope of the requirements for Type C gas gathering pipelines are risk-based; basic damage prevention provisions apply to all Type C gas gathering pipelines while other safety requirements apply to larger-diameter Type C gas gathering pipelines or those Type C gas gathering pipelines that are located near buildings intended for human occupancy.

III. Discussion of NPRM Comments, Gas Pipeline Advisory Committee Recommendations, and PHMSA Response

The comment period for the NPRM ended on July 7, 2016. PHMSA received approximately 300 submissions to the docket containing thousands of comments on the NPRM. Submissions were received from the NTSB; groups representing the regulated pipeline industry; groups representing public interests, including environmental groups; State utility commissions and regulators; members of Congress; individual pipeline operators; and private citizens. PHMSA also received late-filed comments to this rulemaking from the major industry trade associations and others following advisory committee meetings as discussed below. Consistent with DOT Order 2100.6 and 190.323, PHMSA considered all comments, including those that were filed late, given their relevance to the rulemaking and the absence of additional expense or delay resulting from considering these comments.

Some of the comments PHMSA received in response to the NPRM were considered in finalizing the 2019 Gas Transmission Rule targeted at statutory mandates, while other comments were considered in response to the third final rule on gas gathering pipelines (under RIN 2137–AE38). In this final rule, PHMSA considers those comments that are relevant to repair criteria, IM improvements, cathodic protection, MOC, and other related amendments. PHMSA does not address the comments on pipeline safety issues that were beyond the scope of the NPRM and, therefore, beyond the scope of this final rule. However, that does not mean that PHMSA determined the comments lack merit or do not support additional rules or amendments. Such issues may be the subject of other existing rulemaking proceedings or may be addressed in future rulemaking proceedings. The remaining comments reflect a wide variety of views on the merits of particular sections of the proposed regulations.

The Technical Pipeline Safety Standards Committee, commonly known as the Gas Pipeline Advisory Committee (GPAC or ''the committee''), is a statutorily mandated advisory committee that advises and comments on PHMSA's proposed safety standards, risk assessments, and safety policies for natural gas pipelines prior to their final adoption. The GPAC is one of two pipeline advisory committees focused on technical safety standards that were established under the Federal Advisory Committee Act (Pub. L. 92–463) and section 60115 of the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*). Each committee consists of approximately 15 members, with membership equally divided among Federal and State agencies, regulated industry, and the public. The committees consider the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

Due to the size and technical detail of the NPRM, the GPAC met 5 times in 2017 and 2018 to discuss the proposed

regulations applicable to gas transmission pipelines. The GPAC convened one time in 2019 to discuss the provisions related specifically to gas gathering pipelines.[17] During those meetings, the GPAC considered the specific regulatory proposals of the NPRM and discussed various comments made on the NPRM's proposal by stakeholders, including the pipeline industry at large, public interest groups, and government entities. To assist the GPAC in its deliberations, PHMSA presented a description and summary of the major proposals in the NPRM and the comments received on those issues. Stakeholders could comment on the proposals during the meeting prior to the committee discussion. PHMSA assisted the committee in fostering discussion and developing recommendations by providing direction on which issues were most pressing.

For the proposals addressed in this final rule, the committee came to consensus when voting on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the NPRM's provisions. In many instances, the committee recommended changes to certain proposals that the committee found would make the rule more feasible, reasonable, cost-effective, or practicable.

This section discusses the substantive comments on the NPRM that were submitted to the docket, as well as the GPAC's recommendations. They are organized by topic and include PHMSA's response to, and resolution of, those comments.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

i. Threat Identification, Data Collection, and Integration—§ 192.917(a) and (b)

1. Summary of PHMSA's Proposal

Subpart O of 49 CFR part 192 prescribes requirements for managing pipeline integrity in HCAs and requires that operators identify and evaluate all potential threats to each covered pipeline segment. Operators are required to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment that informs the operator's baseline assessment schedule and reassessment intervals as well as any additional P&M measures that may be needed for the covered segment. The regulations also require operators to address particular threats, such as third-party damage and manufacturing and construction defects. For these requirements, the regulations reference, through incorporation, ASME/ANSI B31.8S.

For threat identification, the regulations in § 192.917 specify that the potential threats operators must consider include, but are not limited to, the threats listed in section 2 of ASME/ANSI B31.8S. Those threats are grouped into time-dependent threats, static or resident threats, time-independent threats, and human error. In performing data gathering and integration, operators must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, operators must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, which are the year of installation; pipe inspection reports; leak history; wall thickness; diameter; past hydrostatic test information; gas, liquid, or solid analysis; bacteria culture test results; corrosion detection devices; operating parameters; and operating stress level. An operator must also conduct a risk assessment that follows ASME/ANSI B31.8S section 5.

In a risk-based IM approach, data collection and integration is the backbone of an effective IM program. The PG&E incident exposed several problems in the way operators collect and manage pipeline condition data, showing that some operators have inadequate records regarding the physical and operational characteristics of their pipelines. The use of erroneous information leads to insufficient understanding of pipeline risks and incorrect integrity-related decision making. PG&E's IM program was missing or misidentified data elements that were necessary to characterize risk correctly and establish and validate MAOP, which is critically important for providing an appropriate margin of safety to the public.

Threat identification, data collection, and data integration are basic pillars on which IM was founded with the issuance of the 2003 IM rule. As specified in § 192.907(a), operators were to start with a framework, evolve that framework into a more detailed and comprehensive program, and continually improve their IM programs.[18] Operators would accomplish this constant improvement, in part, through learning about the IM process itself and learning more about the physical condition of their pipelines via IM assessments and the development of that data.

Data collection for new pipeline construction is relatively simple. However, collecting missing material property records for pipeline segments that have been in the ground for years can be challenging, as such data collection must be completed through integrity assessments or excavations. Operators are required to identify missing data and apply conservative assumptions, but incomplete data presents issues for risk assessment. The over-application of assumptions in the absence of real data, even if those assumptions are conservative, can lead to skewed or otherwise inaccurate risk analysis results.

In the NPRM, PHMSA proposed to revise § 192.917 to include specific requirements for collecting, validating, and integrating pipeline data. These requirements would add further specificity to the data integration regulations, list specific pipeline attributes that must be included in these analyses, explicitly require that operators integrate analyzed information, and require that data be verified and validated. PHMSA also proposed to require that operators use validated, objective data to the maximum extent practical. To the degree that subjective data from subject matter experts (SME) must be used, PHMSA would require that operator programs include specific features to compensate for SME bias, including training SMEs to recognize or avoid bias, and using outside technical experts or independent expert reviews to assess SME judgment and logic. Further, in § 192.917(b)(3), PHMSA proposed to require operators to identify and analyze spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings and evidence of pipeline damage where overhead imaging shows evidence of encroachment), stating that storing or recording the information in a common location, including a geographic information system (GIS) alone, is not sufficient.

2. Summary of Public Comment

Many stakeholders agreed with PHMSA that verified and validated data is important for data integration and threat analysis. The NTSB expressed support for the proposed additions to the IM analysis requirements and commented that expanded pipeline record and data requirements are a significant safety improvement in the management of pipelines through their service lifecycle. However, certain

[17] Specifically, the committee met on January 11–12, 2017; June 6–7, 2017; December 14–15, 2017; March 2, 2018; March 26–28, 2018; and June 25–26, 2019. Information on these meetings can be found at *regulations.gov* under docket no. PHMSA–2011–0023 and at PHMSA's public meeting page: *https://primis.phmsa.dot.gov/meetings/.*

[18] See 68 FR 69789.

stakeholders had concerns with PHMSA's specific proposed changes.

PHMSA also received comments from the industry on the feasibility of threat identification, data gathering, and integration. The American Petroleum Institute (API) stated that while the totality of attributes listed in proposed § 192.917 should not pose a major burden on the industry, some specific attributes listed may not be feasible to obtain in practice. Enterprise Products stated that including just four or five attributes that point to a specific conclusion would be more useful than the lengthy list of attributes in the proposed provisions. A few commenters requested PHMSA clarify what they meant by ''data integration, verification, and validation,'' as these terms were not clear.

The Interstate Natural Gas Association of America (INGAA) and the Texas Pipeline Association (TPA) expressed concern that the proposed provisions are more prescriptive than the ASME/ANSI standard that is referenced in the current IM requirements. INGAA also commented that PHMSA's proposed inclusion of specific attributes from ASME/ANSI B31.8S in the regulatory text alongside the existing incorporation by reference of that standard could cause confusion. INGAA further stated that PHMSA should retain the current regulatory language requiring operators to ''consider'' the relevant data for covered segments and similar non-covered segments, instead of adopting the proposed provisions that would require data evaluation for non-covered segments. INGAA also stated that many of the data elements required by ASME/ANSI B31.8S are not available for older pipelines, which can include non-covered segments. INGAA and other commenters also asserted that PHMSA should provide sufficient time for operators to comply with the proposed data validation and integration requirements given the expansion of § 192.917(b)(1) to non-covered segments.

Several commenters provided input on PHMSA's proposed requirements to address SME bias. INGAA suggested PHMSA should delete the references to SME bias listed in § 192.917(b)(2) and replace the text with more general language to include peer reviews and external SME verification, citing this alternative as more consistent and clearer than what PHMSA proposed. National Fuel stated that using outside technical experts for bias control would be unnecessarily costly to pipeline operators. The American Gas Association (AGA) asserted that using outside technical subject matter experts for bias control is already standard practice within the industry and that it is not necessary to codify it into regulation. PG&E also suggested improvements to the section, stating that there is not an existing industry standard to provide guidance on what constitutes an outside technical expert to perform this specific function, and PHMSA should provide further guidance on this topic.

Several industry trade groups provided input on the proposed language in § 192.917(b)(3) that would require operators to identify and analyze the spatial relationship among anomalous information (*e.g.,* corrosion coincident with foreign line crossings and evidence of pipeline damage where overhead imaging shows evidence of encroachment). TPA stated that it disagreed with PHMSA's proposal in this paragraph and commented that this requirement would impose a financial burden on smaller operators. PG&E asserted that the proposed language in § 192.917(b)(3) should be removed entirely since it was not clear how to comply with these requirements.

At the GPAC meeting on June 7, 2017, the committee noted that the NPRM's proposed revisions to § 192.917 do not include a way for operators to address the lack of availability of some data sets. The committee suggested that operators could assume the pipeline segment is susceptible to the threat associated with the missing data. The committee also questioned the purpose for the extensive, prescriptive data list, with some members believing it would turn into a compliance paperwork exercise without safety benefit. This, in turn, led to a discussion of how an operator demonstrates to a regulator that it is performing an effective risk analysis and whether that is a checklist of items or performing actions to generate better safety outcomes. Some committee members suggested PHMSA clarify that operators should only collect the pertinent data for operations and maintenance (O&M) tasks.

Committee members representing the industry noted the rule has no timeframe for the implementation of data collection and challenged the conclusion in the preliminary regulatory impact assessment (PRIA) that the data collection elements had a cost of zero, as databases may need to be upgraded to implement the listed attributes. Members representing the industry also requested PHMSA remove the proposed requirement to address SME bias; however, other committee members representing the public noted that SME bias in risk analysis is recognized across different disciplines and reflects a need to address how humans think about risk. Certain committee members representing the industry were also concerned that the requirements mandated the use of a GIS, which might be impractical for small operators.

Following the discussion, the committee voted 11–0 that the proposed rule, as published in the **Federal Register**, with regard to the provisions for IM clarifications regarding threat identification, data collection, and data integration, were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the list of pipeline attributes in the section to be more consistent with the existing regulations and the ASME/ANSI B31.8S standard, and if PHMSA also added language requiring operators to collect data that is pertinent and that a prudent operator would collect. The committee also recommended PHMSA require operators to have implementation procedures in place 1 year after the effective date of the rule, with full incorporation of all listed attributes by 3 years after the effective date of the rule, and strike requirements for operators to use a GIS in complying with these provisions. Finally, the committee recommended that PHMSA address SME bias by considering some of the specific suggestions made by committee members at the meeting, including striking or revising the last sentence of the provisions.

3. PHMSA Response

The current regulations at § 192.917(b) explicitly require that, at a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S. Operators may not ignore that requirement to collect the minimum set of data needed for a robust threat evaluation and risk assessment. PHMSA agrees that some assumptions regarding threat applicability based upon pipe type, operating parameters, and operating environment (*i.e.,* weld seam type, manufacturing date, coating type, operating pressure versus percentage specified minimum yield strength (SMYS), operating temperature, lack of cathodic protection (CP) or the time when CP was placed on the system, and location) can be made even if the pertinent data is missing. For example, a lack of CP on a pipeline system would mean that the pipeline is more prone to external corrosion, no matter what type of external coating is on the pipe. High operating temperatures, pressures, and a lack of quality pipe coating can also be risk factors for cracking.

Regarding INGAA's comment on retaining the current regulatory

language requiring operators to ''consider'' the relevant data for covered segments and similar non-covered segments rather than adopting the proposed provisions that would require data evaluation for non-covered segments, PHMSA reminds operators that the current requirement states that operators must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. At a minimum, operators must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S and consider both on the covered segment and similar non-covered segments the data and conditions specific to each pipeline. PHMSA's clarification in this final rule that operators must ''analyze'' the information that they are already required to collect, integrate, and consider, is consistent with the existing requirement, as performing those actions is, essentially, an analysis. Nevertheless, PHMSA is changing ''consider'' to ''analyze'' to reinforce that operators must have documentation demonstrating that they have reviewed the data for similar vintage pipe to determine whether they have threats or not that should be remediated.

PHMSA further disagrees that it is appropriate to allow industry to continue to ''consider'' data elements selectively or that only specifying a few required data elements is the best approach. While some pipelines without associated data may not pose a risk, some may pose a significant risk. Comprehensive data is the best way to ensure an appropriate assessment and, in turn, reduction of risk. The addition of the specific data elements in the regulatory text clarifies PHMSA's expectations of data collection. PHMSA agrees, however, that some data elements may not be pertinent to all pipeline segments. Therefore, in this final rule, PHMSA is revising the proposed requirement to specify that the operator must collect ''pertinent'' data ''about pipeline attributes to assure safe operation and pipeline integrity, including information derived from operations and maintenance activities,'' as recommended by the GPAC. Regarding the cost of this data collection, all the proposed elements were listed in ASME/ANSI B31.8S. As that standard has been incorporated by reference since 2004 for covered segments (*i.e.,* HCAs), collecting the listed data should not be a new or an extensive exercise for any prudent operator with appropriate processes in place. While specifying the list of data elements in the regulatory text is new, the elements listed have been incorporated by reference since the promulgation of subpart O and are not more prescriptive than the current regulations. Further, PHMSA disagrees that continuing to incorporate by reference ASME/ANSI B31.8S as well as specifying individual data elements will confuse operators.

Additionally, in response to comments and the GPAC recommendation, PHMSA is revising the listing of data elements to be more consistent with ASME/ANSI B31.8S. In some cases, PHMSA has clarified the meaning of generic terms in the data collection list found in ASME/ANSI B31.8S within this final rule. For example, where the ASME/ANSI standard lists ''material properties,'' PHMSA has elaborated by specifying these are ''material properties including, but not limited to, grade, SMYS, and ultimate tensile strength.'' In another example, where the standard lists ''pipe inspection reports,'' PHMSA has itemized, in this final rule, the pipe inspections required by part 192 and that are commonly performed by operators.

PHMSA agrees with commenters that sufficient time should be allotted for operators to comply with the data integration requirements. However, PHMSA also agrees with the comments made that operators should have been collecting and accounting for the pertinent items of this data set since the publication of the original IM rule almost 20 years ago. Therefore, in this final rule, PHMSA is providing a phased-in timeframe. The GPAC recommended that the implementation timeframe should begin in year 1, with full incorporation by 3 years. Given the existing requirements for collecting and using the data elements from ASME/ANSI B31.8S, and given the discussion at the GPAC meetings and the public comments received, PHMSA has revised this final rule to require that an operator must begin data integration on the effective date of the rule and integrate all attributes within 18 months of this rule's publication date.

Regarding comments calling for clarification of what ''data integration, verification, and validation'' meant, PHMSA notes that, at a minimum, an operator should consider the same set of data on a periodic basis and analyze changes and trends that would indicate the need for additional integrity evaluations.

Regarding SME bias, PHMSA believes that it is important for operators to address SME bias in data collection and risk assessment to account for the reality of how humans think about risk. Operators should take this into consideration when incorporating SME opinion as fact or when treating input from all SMEs as equivalent. While some operators may effectively account for SME bias, PHMSA has not observed this to be universal practice in the industry. To the point commenters made that using outside technical experts for bias control is unnecessarily costly, PHMSA notes that the use of outside technical experts would be optional: this final rule contemplates that operators could also employ training to ensure information provided by their own SMEs is consistent and accurate. While commenters also correctly noted that there is not an existing industry standard as to what constitutes an outside technical expert or an independent technical expert for SME bias control, an operator is ultimately responsible for determining the appropriateness and conductors of such a review. As a part of such a review, should an operator decide to have another SME review input from another SME, the operator must use a qualified SME—*e.g.,* an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. Operators would be required to document that the SME is appropriately knowledgeable and experienced in the subject being assessed.

PHMSA was persuaded, consistent with a GPAC recommendation, that some adjustments to the rule language are appropriate for clarity, or to eliminate redundant language, within the non-exhaustive list of specific types of data to be collected at § 192.179(a) and (b). Specific changes adopted in this final rule include the following:

- Section 192.917(a)(2): deleted a redundant reference to ''or equipment defects;''
- Section 192.917(b)(1)(iii): deleted explicit material properties (*e.g.,* hardness, chemical composition) from a non-exhaustive list of material properties;
- Section 192.917(b)(1)(xxiv): added ''seam cracking'' within the list of pipe operational and maintenance inspection reports to be reviewed;
- Section 192.917(b)(1)(xxv): deleted a redundant reference to ''outer/inner diameter corrosion monitoring;''
- Section 192.917(b)(1)(xxviii): eliminated specific examples of ''encroachments;'' and
- Section 192.917(b)(1)(xxxvi): deleted a redundant savings clause for ''other pertinent information'' when the lead-in to the section noted that the information listed was non-exhaustive.

PHMSA has also, consistent with a recommendation by the GPAC revised the rule by (1) requiring that operators employ adequate control measures for SME input to ensure consistent and accurate information rather than ''correct'' SME ''bias;'' and (2) requiring that operators document the names and qualifications of individuals who approve SME input rather than document the names of the SMEs and the information provided.

Concerning the use of a GIS, the NPRM's proposed revisions to § 192.917 were not intended to imply that all operators were required to implement a GIS system but were meant to clarify that data integration is not achieved solely by maintaining spatially located data in a GIS system. Accordingly, PHMSA has revised this final rule as recommended by the GPAC to delete reference to the use of a GIS system and maintain the core requirement to identify and analyze spatial relationships among anomalous information.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

ii. Risk Assessment Functional Requirements—§ 192.917(c)

1. Summary of PHMSA's Proposal

Section 192.917(c) requires operators to perform a risk assessment as part of an effective IM program. A risk assessment is an important element of a good IM plan. PHMSA analyzed the issues related to risk assessments that the NTSB identified in its investigation and held a workshop on July 21, 2011, to address perceived shortcomings in the implementation of IM risk assessments. PHMSA also sought input from stakeholders on these issues in the ANPRM. Based on the input received from both the ANPRM and the workshop, PHMSA determined that additional clarification was needed to emphasize the functions that risk assessments must accomplish and to elaborate on effective processes for risk management, both of which are critical to effective IM.

To address these issues, PHMSA proposed to clarify the risk assessment aspects of the IM regulations at subpart O by including the following functional requirements for risk assessments that operators should perform to assure pipeline integrity:

- Evaluate the effects of interacting threats;
- Ensure validity of the methods used to conduct the risk assessment;
- Determine additional P&M measures needed;
- Analyze how a potential failure could affect an HCA, including the consequences of the entire worst-case incident scenario, from initial failure to incident termination;
- Identify how each risk factor, or each combination of risk factors that simultaneously interact, contribute to risk at a common location;
- Account and compensate for uncertainties in the model and the data used in the risk assessment; and
- Evaluate risk reduction associated with candidate activities, such as P&M measures.

2. Summary of Public Comment

Public interest groups supported PHMSA's proposed revisions at § 192.917(c) to strengthen the functional requirements for risk assessment models. The Pipeline Safety Trust (PST) stated that the risk assessment models currently used by pipeline operators are inadequate and further noted that the proposed provisions could go farther to advance risk assessment quality. Other GPAC members representing the public supported the proposed revisions at § 192.917(c) during the committee meetings and noted that the NPRM language for this topic was written using a risk-informed approach that articulated the functions and purposes of risk assessments without being prescriptive as to the method or process to be used, which is consistent with IM principles.

Multiple industry trade associations and individual operators acknowledged the importance of risk assessments but believed that the proposed revisions at § 192.917(c) were too prescriptive. Several individual operators emphasized their voluntary efforts to improve their risk models and disagreed that the industry's risk models needed further prescription.

Many commenters emphasized that different pipeline systems are susceptible to different threats and believed that operators are best suited to determine which threat analyses are relevant to their systems. Multiple operators expressed the opinion that the proposed revisions at § 192.917(c) would require operators to expand datasets substantially but would contribute little benefit to risk identification, suggesting instead that integrating unnecessary datasets would distract from other safety efforts. AGA and several individual operators requested that PHMSA give operators discretion to select which data sets to incorporate into risk assessments for their system.

Some commenters requested that PHMSA specify what the NPRM meant when it proposed to revise § 192.917(c) to require operators to ''validate'' data. These commenters expressed doubts regarding the technical feasibility of implementing the proposed regulations in § 192.917(c), noting that some of the data PHMSA proposed requiring for the validation of risk assessment models is not available. These commenters proposed that operators be permitted to apply conservative values or values determined using engineering judgement. Southwest Gas Corporation, Paiute Pipeline, and Consumers Pipeline expressed concern that developing the newly required datasets would require the usage of ILI tools that their pipelines are not configured to accommodate. These commenters stated that gathering these datasets would present costs that were not captured by PHMSA's PRIA because PHMSA did not account for the cost of making lines piggable.

Multiple commenters were concerned that the proposed revisions would make operators' current relative risk models invalid and would require a transition to quantitative or probabilistic risk models. Similarly, API agreed with that assessment and noted that quantitative and probabilistic models are not useful or appropriate for the analysis, prediction, or prevention of low-frequency, high-consequence events such as the PG&E incident. Further, API noted that the probabilities of certain infrequent circumstances and conditions occurring at a single location and single time are so low that the quantitative or probabilistic risk models would not identify them because there are no statistics available from which to predict them. AGA asserted that the proposed requirements deviate from industry standards and that PHMSA did not provide sufficient justification for this departure. Commenters also emphasized the high costs associated with implementing quantitative risk models, which can include the procurement of specialist expertise, development of new datasets, and transition to a GIS or other new database management system.

Kern River requested clarification regarding which elements of § 192.917 need to be included in an operator's risk model and which elements only need to be included in the overall IM plan. They noted that integrity assessment method determinations, repair decisions, P&M measures selection, root cause analyses, and similar pipe studies all play a part in the overall IM plan and have at times overlapping, but also unique, requirements for data gathering, integration, and threat analysis.

AGA and several individual operators expressed concerns that the proposed rule does not provide a timeline for implementing new risk assessment requirements, thereby implying that operators must implement new requirements by the rule's effective date. Multiple operators and industry trade associations requested that operators be permitted to develop their own implementation schedules or provided suggestions for specific implementation schedules. For example, Enterprise Products requested that PHMSA include a 2-year implementation period for operators to incorporate the data integration and risk assessment requirements into their IM programs.

At the GPAC meeting on January 12, 2017, some committee members noted that any revisions to the risk assessment requirements should be deferred until after PHMSA's Pipeline Risk Modeling Work Group issues its pipeline system risk modeling technical document.[19] There was broad support from the committee for the revisions to § 192.917(c) proposed in the NPRM, with members noting the language was consistent with IM principles and was written using a performance-based approach that articulated the functions and purposes of risk assessment without being prescriptive as to the method or process needing to be used. However, some committee members representing the industry expressed concern with the use of the term ''probability'' in the NPRM's proposed revisions to § 192.917(c), which seemed to imply PHMSA intended for operators to be using probabilistic risk assessment techniques.

Following the discussion, the committee voted 11–0 that the proposed provisions for the risk assessment requirements were technically feasible, reasonable, cost-effective, and practicable if PHMSA modified the proposed rule to restore the reference to ASME/ANSI B31.8S, section 5, to clarify that other methods besides probabilistic techniques may be used; change the term ''probability'' to ''likelihood'' and delete the term ''risk factors'' from § 192.917 (c)(2); and provide a 3-year phase-in period for risk assessments to meet the functional objectives specified in § 192.917(c).

3. PHMSA Response

On March 6, 2020, PHMSA published the final report titled ''Pipeline Risk Modeling—Overview of Methods and Tools for Improved Implementation'' from the joint PHMSA/industry working group on risk modeling.[20] However, PHMSA notes that the report is focused exclusively on the models employed and ''best practices'' for using them. The working group did not address other aspects of the proposed rule, including how a risk assessment is used.

PHMSA believes that the revisions to § 192.917(c) are important to include in this rulemaking now, as many operators have not substantially improved their risk assessment techniques or models since the early initial efforts to prioritize baseline assessment plans in 2004, with the findings from the PG&E incident being a prime, national example. Therefore, PHMSA is establishing explicit minimum standards for the functional requirements of a risk assessment to help assure that operators will achieve this specific aspect of a ''more detailed and comprehensive'' program as discussed in the 2003 IM rule.

In the NPRM's proposed revisions to § 192.917(c), when PHMSA used terms such as ''probability'' and ''risk factors,'' it was not intended to imply that an operator must perform probabilistic risk analysis. To address this, PHMSA has modified the rule language to replace the term ''probability'' with ''likelihood'' and restored the reference to ASME/ANSI B31.8S, section 5, for acceptable risk assessment methodologies as recommended by the GPAC. Similarly, and as also recommended by the GPAC, PHMSA has deleted the phrase ''or risk factors'' from paragraph § 192.917(c)(2) for clarity. Whichever risk assessment methodology an operator chooses, the result must meet the functional requirements and accomplish the purposes specified in this final rule.

PHMSA notes that all data elements specified in § 192.917(b) are important for a robust risk assessment. While operators do have the discretion to expand their data collection efforts, this minimum defined data set is required to be used. As was emphasized by multiple operators in their comments, each pipeline system is susceptible to different threats, and the individual operator is best suited to determine these threats. However, an operator needs the specified data elements to identify threats objectively. As noted in the previous section, PHMSA has modified the rule to refer to the ''pertinent'' data elements, including information derived from O&M activities that assure safe operation and pipeline integrity. This revision clarifies that data elements that are not pertinent for a given pipeline segment need not be included in a risk assessment.

Pertaining to comments regarding the validity of the method used, an operator must ensure the soundness of the risk modelling method they are using applicable to the threats to a given pipeline segment, including its specific leak or failure history. To Kern River's comment as to which elements of § 192.917 need to be included in an operator's risk model and which elements need to be included in an operator's IM plan, PHMSA will note that integrity assessment method determinations, repair decisions, P&M measure selection, and root cause analyses are examples of items that could be included in an operator's risk model based on the particular types of threats being assessed. The existing regulations state that a ''particular threat'' is an identified threat being assessed for each covered segment.

As discussed above, some commenters claimed there would be high costs associated with implementing quantitative risk models, which might include the procurement of specialist expertise, the development of new data sets, and a transition to a GIS or other new database management system. PHMSA notes that operators can use the same data they have been, and are currently, collecting when implementing a quantitative risk model. Operators do not necessarily have to ''recollect'' or otherwise change their existing data to use a probabilistic risk model.

Given the state of some operators' risk assessment programs, PHMSA is persuaded that it is reasonable to allow operators a reasonable amount of time to upgrade their risk assessment models, methodologies, and analyses. However, this is an important provision that operators need to implement as soon as practicable. Therefore, and to be more consistent with the implementation for the data attributes discussed earlier, PHMSA is modifying this final rule to allow an 18-month implementation period for this provision.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

iii. Threat Assessment for Plastic Pipe—§ 192.917(d)

1. Summary of PHMSA's Proposal

PHMSA proposed to add to the regulations examples of threats unique to plastic pipe that operators must consider, such as poor joint fusion practices, pipe with poor slow crack

[19] For more information on the work group and its efforts, see *https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-work-group-overview.*

[20] *https://www.phmsa.dot.gov/news/now-available-phmsa-report-pipeline-risk-modeling-overview-methods-and-tools-improved-0.*

growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading. The proposed revisions would not otherwise change the current requirements of § 192.917(d).

2. Summary of Public Comment

PHMSA did not receive any public comments on this section. At the GPAC meeting on June 7, 2017, PHMSA noted in its presentation to the committee that there were no public comments on the issue. Subsequently, the GPAC voted 11–0 that the proposed changes to the provisions for IM clarifications for threat assessments for plastic pipe were technically feasible, reasonable, cost-effective, and practicable, and they did not recommend any additional changes to § 192.917(d).

3. PHMSA Response

Since PHMSA did not receive any public comments or additional GPAC recommendations regarding threat assessment for plastic pipe, the final rule includes the requirement in § 192.917(d) as proposed in the NPRM. PHMSA proposed these changes to highlight these potential threats to both operators and inspectors, and finalizing these requirements will provide additional safety and enforcement awareness.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

iv. Preventive and Mitigative Measures—§ 192.935(a)

1. Summary of PHMSA's Proposal

PHMSA's inspection experience shows that some operators do not implement additional P&M measures based on the evaluation required at § 192.935(a). PHMSA believes that strengthening requirements related to operators' use of insights gained from their IM programs is prudent to ensure effective risk management. Therefore, PHMSA proposed to clarify the expectation that operators use knowledge from risk assessments to establish and implement adequate P&M measures and provided more explicit examples of the types of P&M measures for operators to evaluate.

2. Summary of Public Comment

Several commenters requested that PHMSA revise the requirements at § 192.935(a) to remove the requirement for operators to perform all the listed measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in an HCA. These commenters stated that requiring operators to perform all the measures listed at § 192.935(a) negates the need for a risk analysis, as the rule would then require that operators perform each of the listed actions regardless of whether conditions warrant these actions or whether past efforts have been taken. INGAA suggested that PHMSA should keep the existing language, which states that an operator must base the additional measures on the threats the operator has identified to each pipeline segment. GPAC members representing the industry echoed INGAA's claims during the committee meetings.

During the GPAC meeting on June 7, 2017, the GPAC noted that PHMSA's proposed changes removed a statement that an operator must base additional P&M measures on the threats an operator has identified for each pipeline segment. The proposed text, the members believed, implied an operator would be required to evaluate and implement each listed P&M measure every time. Based on PHMSA's webinars and other discussions, the committee members didn't believe that was PHMSA's intent.

Following that discussion, the committee voted 11–0 that the proposed provisions for strengthening the requirements for applying IM knowledge were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified it was not the agency's intent to require that all listed P&M measures be implemented, and that operators ''must consider'' the listed items.

3. PHMSA Response

PHMSA agrees that all listed measures are not mandatory for implementation in all cases. Requiring an operator to implement P&M measures against threats that might not be applicable to their particular system could be overly burdensome. However, PHMSA has determined that requiring operators to consider the listed measures in their risk analyses and apply them to threats as appropriate is a practical requirement. As recommended by the GPAC, the final rule has been modified to reflect that position; each operator will be required to consider the listed measures and determine the appropriateness of each for their system.

B. Management of Change—§§ 192.13 & 192.911

1. Summary of PHMSA's Proposal

Section 192.911(k) requires that an operator's IM program include a MOC process as outlined in ASME/ANSI B31.8S, section 11. That document guides operators to develop formal MOC procedures to identify and consider the impact of major and minor changes to pipeline systems and their integrity. These changes can include technical, physical, procedural, and organizational changes, and they can be either temporary or permanent changes. Per ASME/ANSI B31.8S, section 11, an operator's MOC process should include the reason for the change, the authority for approving changes, an analysis of the implications of the change, the proper acquisition of the necessary work permits, appropriate documentation, communications of the change to any affected parties, time limitations of the change, and the qualification of staff. The document notes that changes to a pipeline system might require changes to an operator's IM program; similarly, changes to an IM program might also cause changes to a pipeline system. If changes in land use (*e.g.,* increased population) would affect the potential consequence of an incident or the likelihood of an incident occurring, such a change should be reflected in an operator's IM program. The operator should also reevaluate threats accordingly. In short, the MOC process outlined by ASME/ANSI B31.8S helps to ensure that an operator's IM process remains viable and effective as changes to pipeline systems occur or new data becomes available.

Inadequately reviewed or documented design, construction, maintenance, or operational changes can contribute to pipeline failures. In the PG&E incident, the NTSB investigation determined that a substandard piece of pipe was substituted in the field without proper authorization, design review, or approval. PHMSA has subsequently determined that more specific attributes of the MOC process should be explicitly codified within the text of §§ 192.13 (general requirements) and 192.911(k) (IM requirements). As a result, PHMSA proposed to require that operators have a MOC process that includes the reasons for the change; the authority for approving changes; an analysis of implications; the acquisition of required work permits; and evidence documenting communication of the change to affected parties, time limitations, and the qualification of staff.

2. Summary of Public Comment

Public interest groups, such as the PST, and the National Association of Pipeline Safety Representatives (NAPSR) agreed with and supported the proposed MOC provisions, stating that these provisions would enhance pipeline safety. Several individual pipeline operators and trade associations opposed the proposed MOC provisions, stating that the provisions are generally too broad and would be applied to many routine activities that already have established procedures. More specifically, AGA stated that they would create a new requirement for each transmission operator to have a formal MOC process to document and evaluate all changes to pipelines and processes. They further stated that the proposed revisions are unnecessary due to current industry progress related to MOC and the voluntary adoption of industry consensus standards.

Several commenters opposed the proposed addition of four types of changes (design, environmental, operational, and maintenance), asserting that these elements are not included in current industry standards or recommended practices. Similarly, INGAA asserted that PHMSA should eliminate the changes it proposed to § 192.13 that go beyond the recommendations of ASME/ANSI B31.8S. These commenters stated that PHMSA significantly underestimated the impact and burden caused by codifying and expanding the scope of MOC.

Several commenters, including AGA, API, and INGAA, opposed the proposed immediate implementation of the MOC provisions, with some commenters requesting an implementation period of 1 to 5 years. These commenters stated that the proposed changes were significant and would need to be incorporated into existing MOC processes, and that additional time would be needed to complete this in an effective manner. Many commenters also expressed concern over the retroactive application of the proposed MOC provisions.

At the GPAC meeting on January 12, 2017, the committee voted 8—2 that the proposed MOC revisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA provided a 2-year phase-in period for the regulations as they pertain to non-IM pipeline assets, provided a notification procedure for justified extensions, clarified the requirements only covers significant changes that affect safety and the environment, and clearly stated that the revisions do not apply to distribution or gathering lines. The dissenters in the vote (representatives from the Environmental Defense Fund (EDF) and PST) were members representing the public, who thought that the proposed revisions were acceptable as proposed in the NPRM, the phase-in period recommended by the majority of the GPAC was too long, and that there was no reason that the proposed revisions should not apply to gathering lines.

3. PHMSA Response

PHMSA believes that an operator must understand the impacts that their decisions have on safety and the environment. Therefore, PHMSA believes that specifying the types of changes that must be addressed under a MOC program is appropriate. PHMSA also believes that the proposed changes to the MOC provisions conform with the requirements and intent of ASME/ANSI B31.8S.

However, based on the comments received and GPAC recommendations, PHMSA is persuaded that, as published in the NPRM, the language of proposed § 192.13(d) could be overly broad. Therefore, PHMSA has revised the requirement to specify the requirement applies to a ''significant change that poses a risk to safety or the environment'' to limit the application of this requirement to significant changes, as the GPAC recommended. Additionally, and as also recommended by the GPAC, PHMSA is specifying that § 192.13(d) is not retroactive and applies only to onshore transmission pipelines (*i.e.,* not gathering or distribution pipelines).[21]

PHMSA agrees that operators should be afforded time to comply with this new requirement, but also believes that operators can apply this process to non-HCA assets more promptly than the period that the GPAC recommended. Therefore, operators have 18 months for the MOC process to be fully incorporated for non-HCA pipeline segments. PHMSA is also including a notification procedure in accordance with § 192.18 for operators to apply for an extension, of up to 1 year, of the compliance deadline. PHMSA believes including this compliance deadline strikes a balance between the GPAC recommendation and the implementation of a procedure that operators already have in place for HCA pipeline segments, and including a notification procedure to provide operators with more time, if necessary, effectively implements the GPAC recommendations.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

i. Applicability

1. Summary of PHMSA's Proposal

Incidents attributed to corrosion continue to occur, which demonstrates that the current requirements can be more effective at preventing incidents caused by certain types of corrosion. This includes compromised pipe or pipe coating caused by damage from construction, cathodic protection deficiencies, interference currents, and internal corrosion. As a result, PHMSA proposed several changes to the regulations for corrosion control, including new requirements for pipe coating assessments, protective coating strength, P&M measures, and additional mitigation of stray current (also referred to as interference current). PHMSA also proposed changes regarding gas stream monitoring program requirements to mitigate internal corrosion. These proposed revisions were made in §§ 192.319, 192.461, 192.465, 192.473, and 192.935(f) and (g) and are discussed more thoroughly in this section. PHMSA also proposed to add a new § 192.478 for the monitoring and mitigation of internal corrosion.

2. Summary of Public Comment

The Coalition to Reroute Nexus, the Michigan Coalition to Protect Public Rights-of-Way, NAPSR, and the PST supported the proposed changes regarding corrosion control and pipeline condition monitoring. Earthworks suggested that PHMSA issue even more stringent requirements given the number of post-Carlsbad incidents that have occurred due to corrosion.[22] The Pipeline Safety Coalition, the Public Service Commission of West Virginia, and the Pennsylvania Public Utility

[21] PHMSA stated, in response to written comments submitted in the docket and discussion during the January 2017 GPAC meeting, that it would in the final rule limit application of the NPRM's proposed management of change amendments at § 192.13(d) to exclude gas distribution and gathering lines. PHMSA notes, however, that (1) PHMSA has undertaken a rulemaking (under RIN 2137–AF53) that will consider extending those or similar requirements to gas distribution pipelines as required by a mandate in section 204 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (Pub. L. 116–260)); and (2) PHMSA may consider extending those or similar requirements to gas gathering lines as PHMSA obtains more information on the safety risks of such pursuant to enhanced reporting requirements codified by PHMSA's Gas Gathering Final Rule.

[22] An incident near Carlsbad, NM, on August 19, 2000, which was caused due to corrosion, killed 12 people and caused nearly $1 million in damage. The incident was a catalyst for PHMSA's IM program requirements for pipelines.

Commission stated that not all gathering pipelines should be exempt from corrosion monitoring.

Some commenters requested clarification regarding whether the proposed provisions were intended to include transmission, distribution, and gathering pipelines. Other commenters provided input on whether gathering pipelines should be included in the corrosion control requirements, especially alternating current voltage gradient (ACVG) and direct current voltage gradient (DCVG) inspections in proposed § 192.461.

During the meeting on June 7, 2017, GPAC committee members questioned whether the corrosion control requirements would apply to gathering lines—the presumption among the majority of the members was that the requirements were not intended to include gathering or distribution lines. The committee provided other feedback specific to the applicability and implementation of specific corrosion topic areas, which are discussed in the applicable sections below.

3. PHMSA Response

PHMSA has considered the comments received regarding the applicability of the proposed corrosion control requirements. PHMSA stated at the June 2017 GPAC meetings, in response to comments received on the NPRM and the discussions during the GPAC meeting, that it would in the final rule exclude gathering and distribution pipelines from the NPRM's proposed requirements in subpart I related to corrosion control. Accordingly, PHMSA has revised § 192.9 to exempt gathering lines from several of these requirements. PHMSA, however, may consider expanding this provision to gathering lines in the future. Comments on the specific provisions proposed for corrosion control are addressed in the following sections.

As to commenters requesting the regulations be made even more strict than proposed, PHMSA notes that changes more stringent than those proposed would require further notice. PHMSA believes that currently, there is also not sufficient data to justify more stringent changes. PHMSA will continue to review all data sources on the subject, including incident and annual reports, and consider more stringent corrosion control safety requirements in a future rulemaking if there is data supporting the need.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

ii. Installation of Pipe in the Ditch and Coating Surveys—§§ 192.319 and 192.461

1. Summary of PHMSA's Proposal

Section 192.319 prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. While most operators perform the required high-voltage holiday detection [23] on the pipeline prior to it being placed into the ditch, pipe coating can sometimes be damaged during the handling, lowering, and backfilling process, which can compromise its ability to prevent external corrosion. To address this problem, PHMSA proposed to require that onshore gas transmission pipeline operators perform an above-ground indirect assessment through an ACVG or DCVG survey to identify locations of suspected damage promptly after an operator completes the backfilling process. Per the proposal, operators would remediate any moderate or severe coating damage issues identified by such an assessment, which, was defined as where there are voltage drops of greater than 35 percent for DCVG or 50 dBμV for ACVG.

Section 192.461 prescribes requirements for protective coating systems. PHMSA notes that pipe coating can disbond [24] from the pipe and shield the pipe from CP. The NTSB determined that this was a significant contributing factor in the major crude oil spill that occurred near Marshall, MI, in 2010. As a result, PHMSA determined that additional requirements are needed to specify that coating should not impede cathodic protection. Further, and as discussed above, PHMSA determined that additional requirements are needed so that operators verify that pipeline coating systems for protection against external corrosion have not become compromised or damaged during the installation and backfill process performed during maintenance, repairs, or pipe replacement.[25]

In the NPRM, PHMSA proposed to revise § 192.461(a) to require that pipelines have sufficient coating to protect against damage from being handled. PHMSA also proposed to add § 192.461(f) to require operators to perform an above-ground coating survey within 3 months of placing the pipeline into service and require operators to repair moderate or severe coating damage within 6 months of the assessment.

2. Summary of Public Comment

Stakeholders representing the public, including NAPSR and the PST, generally agreed with and supported the revisions to this section, stating that such requirements would increase safety and were a good step towards reducing the number of incidents that occur due to corrosion. Many commenters stated that ACVG/DCVG surveys are not always feasible and that PHMSA should not limit the tools for performing coating surveys to the two types specified in §§ 192.319 and 192.461(f). For example, INGAA stated that PHMSA did not provide justification for requiring coating surveys, such as ACVG and DCVG, to be used to detect coating issues after construction or after performing a repair or replacement. INGAA further stated that PHMSA should allow operators to use other assessment technologies, such as close interval surveys (CIS) and high-resolution geometry ILI inspection tools, to detect and manage post-construction, post-repair, and post-replacement conditions that contribute to external corrosion.

AGA and AGL Resources (now Southern Company Gas) commented that depth of cover and excessive pavement can make indirect surveys impossible. Further, AGA stated that while conducting post-construction surveys is industry best practice, activities that are not always feasible for operators to complete should not be codified within the regulations.

NACE expressed concern that ACVG and DCVG surveys do not address the stated goal of identifying coatings that impede cathodic protection and objected to setting specific thresholds for these tests. Similarly, INGAA stated that if the requirements for operators to perform coating surveys using ACVG and DCVG are finalized, the proposed voltage drop threshold value in § 192.461(f) should be eliminated.

Industry commenters also stated objections or suggested limitations to the timeframe proposed in § 192.461(f) regarding when these surveys should be performed, stating that the 3-month timeline is inconsistent with the 1-year period allowed to install cathodic protection after the construction of a

[23] ''Holidays'' are essentially holes or gaps in the coating film that exposes the pipeline to corrosion. The inspections of pipeline coating through electronic defect detectors is commonly also referred to as ''jeeping.''

[24] Disbonding is the failure of a coating to adhere to the underlying substance to which it was applied. Specific to pipelines, it is a loss of adhesion between the cathodic coating and the pipe due to a corrosive reaction taking place.

[25] This is similar to a proposal in § 192.319 for new construction.

pipeline in existing § 192.455(a)(2). New Jersey Natural Gas expressed concern that 3 months may not be adequate both to procure qualified personnel and to perform these surveys and have a fully mature cathodic protection system to perform a successful coating assessment. NAPSR believed that, unless there was a technical reason for the 3-month deadline for the surveys, the timeline might be too conservative due to service procurement and seasonal conditions. Therefore, they recommended extending the assessment deadline.

API and Enterprise Products commented that PHMSA does not provide any supporting evidence that backfilling a ditch for an onshore transmission pipeline is, or has been, an issue meriting the need for ACVG or DCVG surveys to assess coating integrity. Further, API and Southern California Gas Company stated that § 192.319(a) already requires all operators of transmission gas pipelines to ''protect the pipe coating from damage,'' either in initial installation, or any time the pipe is exposed and backfill material is added. Therefore, the proposed provisions may be duplicative with § 192.461.

At the GPAC meeting on June 6 and 7, 2017, committee members representing the industry echoed many of the comments received, noting also that ACVG and DCVG surveys may not address issues related to coatings impeding CP. Additionally, some of these members noted that coating surveys are not always feasible, and that PHMSA should not limit the tools for performing such surveys. Further, several GPAC members representing the industry suggested that PHMSA should not set specific repair thresholds in the regulations, and that the provisions do not align with current NACE standards.[26] Certain committee members also recommended applying a greater-than-1000-feet standard for this provision, which would match a proposed requirement for external corrosion control under § 192.461 and thought that the timeline for the above-ground coating survey should be extended from 3 months to 1 year to synchronize with current CP installation requirements. The committee also suggested PHMSA clarify the applicability of these provisions is limited to transmission pipelines.

Therefore, the committee voted 10–0 that these provisions proposed at §§ 192.319 and 192.461 were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) raised the repair threshold from ''moderate'' to ''severe'' indications, (2) modified the requirements to apply to segments greater than 1,000 feet in length to be consistent with other similar corrosion control requirements, (3) extended the assessment and remediation timeframe to 6 months after a pipeline is placed into service and made allowances for delayed permitting, (4) adjusted the recordkeeping requirements so that operators would be required to make and retain for the life of the pipeline records documenting indirect assessment findings and remedial actions, and (5) provided flexibility for the use of alternative technology unless the agency objected.

3. PHMSA Response

Operators have historically assumed that coating is functioning as intended after construction. However, the NTSB report on the Enbridge crude oil accident near Marshall, MI, identified shielded CP due to disbonded coating as being a contributing cause of the failure. Whenever an operator backfills a pipeline, there is the potential for coating damage. PHMSA believes that conducting coating surveys after backfill is a reasonable and reliable way for operators to identify coating damage inflicted during the construction process before significant corrosion occurs. This is a means for an operator to confirm, after pipeline construction or replacement, that the pipe coating is not compromised and is functioning as intended.

PHMSA believes that ACVG/DCVG surveys are currently the best and most reliable means of detecting coating damage following construction, as opposed to a CIS survey, which is a complementary survey employed to assess the performance of CP systems. However, PHMSA desires to promote the development of new technologies and methods and acknowledges that other technology could be used for performing coating assessments. Therefore, in this final rule, PHMSA is allowing an operator to notify PHMSA of the intent to use other technology, which it may use unless an objection is received, as was recommended by the GPAC. PHMSA's review of such notification would evaluate whether an operator has demonstrated that the ''other technology'' provides equivalent protection to public safety and the environment compared the existing technologies contemplated by this final rule. As a part of its evaluation, PHMSA considers whether there are technical papers from standard developing organizations that support the use of the new technology, as well as any research that has been conducted on that technology and any usage of the technology in other industries and non-regulated pipelines.

PHMSA disagrees that the voltage drop threshold value used as the remediation criterion should be eliminated from the regulation but does agree that the values in the proposed revisions to §§ 192.319 and 192.461 in the NPRM were conservative as they would indicate ''moderate'' coating damage. Therefore, in this final rule and as recommended by the GPAC, PHMSA is specifying the voltage drop threshold value associated with a ''severe'' indication of coating damage as recommended by GPAC.

As recommended by the GPAC, PHMSA is persuaded that the 3-month proposed timeline may not be practical in all situations and has modified the final rule to allow operators up to 6 months after the pipeline is placed into service to complete the necessary assessments and remediation (with allowance for time required to obtain permits, if required). PHMSA has also included a requirement for the associated recordkeeping requirements of these provisions that includes the editorial changes recommended by the GPAC; specifically, that operators must make and retain for the life of the pipeline records documenting the indirect assessment findings and remedial actions.

PHMSA also modified both sections to apply to segments greater than 1,000 feet in length to be consistent with other corrosion control requirements that were similarly altered in this final rule. PHMSA notes that the application of these requirements to segments greater than 1,000 feet in length is also consistent with conditions that have been applied in several special permit applications.

As a part of the requirements for these sections, PHMSA has provided in the regulatory text that the applicable coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.[27] These might include crossings of major interstates or rivers. An operator must document, in accordance with a technically proven

[26] When the ANPRM was being developed, NACE did have standards for ACVG/DCVG surveys. Since the development of this final rule, NACE has subsequently revised those standards, and there is no longer a standard for these surveys.

[27] For example, coating surveys could require drilling holes in roadways, or digging up pipe—each of which entail their own risks to public safety and the environment. Some of the pipelines that would be surveyed could either be cased or have thick-walls, further complicating efforts to conduct coating surveys.

analysis, any decision made not to perform such a coating survey.

As noted before, PHMSA did not intend for these provisions to apply to gathering or distribution pipelines, and it has clarified the applicability of these provisions to transmission lines only. However, PHMSA may expand the application of these provisions in a future rulemaking.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

iii. Interference Surveys—§ 192.473

1. Summary of PHMSA's Proposal

Interference currents occur when metallic structures pick up a stray electrical current from elsewhere and discharge the current, thereby causing corrosion. These currents can negate the effectiveness of cathodic protection systems. The sources of stray current problems are commonplace; they can result from other underground facilities, such as the cathodic protection systems from crossing or parallel pipelines, light rail systems, commuter train systems, high-voltage alternating current (HVAC) electrical lines, or other sources of electrical energy in proximity to the pipeline. Stray current corrosion is electrochemical corrosion that occurs when potential differences between a high-conductivity steel pipeline and lower-conductivity environments causes the stray current to flow through the pipe and create a corrosion cell. If stray current or interference issues are not remediated, accelerated corrosion could occur and potentially result in a leak or rupture. Section 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. However, specific requirements to monitor and mitigate detrimental interference currents have not been prescribed in subpart I of part 192. Therefore, in the NPRM, PHMSA proposed to explicitly require operators to conduct interference surveys and remediate adverse conditions in a timely manner. Specifically, PHMSA proposed to amend § 192.473 to require that an operator's program include interference surveys to detect the presence of interference currents and take remedial actions within 6 months of completing the survey. Additionally, PHMSA proposed to require in § 192.473 that operators perform periodic interference surveys whenever needed.

2. Summary of Public Comment

Generally, stakeholders representing the public agreed with and supported the revisions to this section, noting that the requirements, as proposed, could help reduce the number of pipeline incidents caused by corrosion. Numerous trade associations and pipeline companies were concerned about the proposed requirements for interference surveys under § 192.473. Commenters, including Atmos Energy Corporation and AGA, expressed doubt regarding the ability of individual operators to obtain the necessary information from electric transmission providers. APGA and INGAA urged PHMSA to limit this new requirement to specific transmission lines, such as those pipelines subject to the threat of stray electric current. Commenters, including INGAA, also stated that the provisions should allow for the phased-in implementation of remediation measures and provided timeframes from 12 to 18 months. Some commenters suggested a lengthened implementation period for this requirement due to the potential difficulties in obtaining the proper permits.

At the GPAC meeting on June 7, 2017, certain committee members believed that these requirements should apply only to lines that are subject to stray current risks and noted that interference surveys might not be feasible depending on the information operators can obtain from electricity transmission companies. Committee members also suggested a phased-in compliance period between 12 and 18 months for these requirements, and noted, similarly to the proposed external corrosion provisions, that the remediation period did not account for activities like obtaining the necessary permits. There was also extensive discussion at the meeting regarding PHMSA's proposed use of the word ''significant'' in context of the level of corrosion that would need to be remediated, with several committee members suggesting that phrase be tied to a numeric threshold for easier compliance. The committee also discussed, at length, what PHMSA's expectation for a remediation ''plan'' is and what the necessary paper trail would look like for compliance.

After discussion, the committee voted 9–0 that the provisions for external corrosion interference currents are technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that the surveys are required for lines subject to stray currents and updated the remediation timeframe to require operators create a remediation procedure and apply for necessary permits within 6 months and complete remediation activities within 12 months with allowances for delayed permitting. The committee also specifically recommended that PHMSA clarify that operators must take remedial action when the interference is at a level that could cause significant corrosion as being 100 amps per meter squared, or if it impedes the safe operating pressure of the pipeline, or if it may cause a condition that would adversely affect the environment or the public.

3. PHMSA Response

PHMSA agrees with commenters that every pipeline segment is not equally subject to stray current. Therefore, in this final rule, PHMSA is modifying § 192.473 as recommended by the GPAC to clarify that interference surveys are required when electric potential monitoring indicates a significant increase in stray current, or new potential stray current sources are introduced. Additionally, PHMSA recognizes the need for objective remediation criteria and has included the criteria recommended by the GPAC, specifically ''greater than or equal to 100 amps per meter squared or if it impedes the safe operation of a pipeline or may cause a condition that would adversely impact the environment or the public.'' PHMSA has also revised this final rule to establish a remediation timeframe of 15 months, with allowance for delayed permitting, as recommended by the GPAC.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

iv. Internal Corrosion—§ 192.478

1. Summary of PHMSA's Proposal

Section 192.477 prescribes requirements to monitor internal corrosion by coupon testing or other means if corrosive gas is being transported. However, the regulation is silent on standards for determining whether corrosive gas is being transported or regarding any changes occurring that could introduce corrosive contaminants in the gas stream. The existing regulations also do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, abnormal conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion because an initial assessment did not identify the presence of corrosive gas.

As such, PHMSA determined that additional requirements are needed to ensure that operators effectively monitor gas stream quality to identify if and when corrosive gas is being transported and to mitigate deleterious gas stream constituents such as contaminants or

Exhibit TRA-3

liquids. In the NPRM, PHMSA proposed to add a new § 192.478 to require onshore gas transmission pipeline operators monitor for deleterious gas stream constituents and evaluate gas monitoring data quarterly. The proposed § 192.478 would also add a requirement for onshore gas transmission pipeline operators to review their internal corrosion monitoring and mitigation program semi-annually and adjust the program as necessary to mitigate the presence of deleterious gas stream constituents. These requirements would be in addition to the existing requirements to check coupons or perform other measures to monitor for the presence of internal corrosion when transporting a known corrosive gas.

2. Summary of Public Comment

NAPSR generally agreed with and supported the addition of this section. They did note, however, that PHMSA should consider the applicability of these requirements to pipelines that are transporting dry, tariff-quality gas. The PST noted that these proposed requirements in this section provided an enforceable mechanism to hold operators accountable for future incidents caused by internal corrosion.

Multiple commenters considered the proposed changes to requirements for internal corrosion control in § 192.478 to be overly prescriptive, particularly regarding gas monitoring and the list of corrosive constituents. INGAA stated that transmission operators are already taking comprehensive steps to address internal corrosion under subparts I and O of part 192 and that proposed § 192.478 should be eliminated for this reason. Atmos Energy Corporation and INGAA asserted that the internal corrosion monitoring timeline proposed in § 192.478(d) is unreasonable and too frequent, particularly for pipeline systems that are not susceptible to internal corrosion. They further stated that mitigation of internal corrosion is necessary only if a pipeline is transporting, or has the potential to transport, corrosive gas. At the GPAC meeting on June 6, 2017, committee members representing the industry supported those comments made by Atmos Energy Corporation and INGAA.

Commenters at the GPAC meeting, including committee members, noted that some distribution operators rely on upstream transmission pipeline gas suppliers to monitor gas quality and do not own any gas monitoring equipment. A committee member noted that if pipeline operators are getting gas from native sources, gathering lines, or underground storage fields, it might be necessary to determine the quality of the gas. Another committee member noted that there are tariffs that prevent certain quantities of constituents that could be internally corrosive from entering a transmission system. That commenter also noted that operators continually monitor for internal corrosion on pipelines transporting tariff-quality gas as a part of IM.

GPAC members also noted that PHMSA should consider harmonizing these requirements with the existing corrosion control monitoring requirements, as they appeared to be duplicative in certain areas.

After discussing the provisions, the committee voted 10–0 that the proposed provisions related to internal corrosion were technically feasible, reasonable, cost-effective, and practicable if PHMSA limited the applicability of the requirements to those pipelines that are transporting corrosive gas and provided additional guidance based on the committee discussion; changed the reference from the use of ''gas-quality monitoring equipment'' to ''gas-quality monitoring methods;'' specified types of technologies operators can use to mitigate potentially corrosive gas streams; and changed the frequency of the monitoring and program review requirements from twice per year to once per calendar year, not to exceed 15 months. The committee also specifically recommended deleting language that was duplicative to existing requirements and instead recommended PHMSA cross-reference those existing requirements in this section.

3. PHMSA Response

PHMSA noted during the GPAC meeting, that, in its experience, transmission pipeline operators measure the quality of the gas coming into their transmission systems. Based on the quality of the gas, transmission pipeline operators are paying suppliers for the gas they receive or are receiving money for the gas they deliver. Therefore, PHMSA assumes transmission pipeline operators have monitoring systems for the quality of the gas entering their systems. PHMSA's intent with the proposed revision of this section was to help ensure that operators were getting that data to the necessary people in their organization. For instance, if an organization's accountants are getting gas quality data due to their work with tariffs, the personnel responsible for operations and integrity management should get that data.

Based on the comments received, PHMSA is revising the scope of proposed § 192.478 in this final rule to limit its applicability to the transportation of corrosive gas and is modifying the proposed language in paragraph (b)(1) to specify that operators perform monitoring at points where gas with potentially corrosive contaminants enters the pipeline. To address concerns regarding the monitoring frequency, PHMSA is changing the requirement from twice per year to once per calendar year, not to exceed 15 months. Making such a change is more consistent with the timeframes for similar requirements in the regulations as revised by this rulemaking and implements the recommendation made by the GPAC.

Further, to harmonize this rule with other rule requirements, PHMSA is deleting proposed paragraph (c), since § 192.477 currently requires the monitoring of internal corrosion. To address comments regarding technology, PHMSA revised paragraph (b)(2) to read ''Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling and inhibitor injections.''

There have been instances where operators do transport corrosive gas by pipeline without investigating the possibility of corrosive effect of the gas on its pipeline and taking steps to minimize internal corrosion.[28] This has happened after operators have withdrawn gas from storage facilities (*e.g.,* caverns) where the gas that was injected became corrosive over time because of properties of the storage facilities. Therefore, there can be scenarios where corrosive gas can enter a pipeline system even if the gas being delivered into the upstream system is non-corrosive.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

v. Cathodic Protection—§ 192.465 & Appendix D

1. Summary of PHMSA's Proposal

Appendix D to part 192, ''Criteria for Cathodic Protection and Determination of Measurements,'' which is referenced in § 192.465(f), specifies requirements for CP of steel, cast iron, and ductile pipelines. Appendix D has not been updated since 1971. The NPRM

[28] In the Matter of Transcontinental Gas Pipe Line Company, LLC, CPF 1–2018–1005, available at *https://primis.phmsa.dot.gov/comm/reports/enforce/documents/120181005/120181005_Final%20Order_06192019.pdf* (last visited March 27, 2020). On December 12, 2016, Transcontinental Gas Pipe Line Company reported an explosion and fire that severely damaged a portion of one of its facilities and station piping, resulting in an estimated $15 million in damage. The root cause was determined to be internal corrosion caused by salt water produced from a storage field during gas withdrawal.

proposed to update appendix D by eliminating outdated guidance on CP and the interpretation of voltage measurement to better align with current standards and PHMSA's understanding of current industry practice.

Section 192.465 currently prescribes that operators monitor CP and take prompt remedial action to correct deficiencies indicated by the monitoring. The provisions in § 192.465 do not specify the remedial actions required to correct deficiencies and do not define ''prompt.'' To address this gap, the NPRM proposed to amend § 192.465(d) to require that operators must complete remedial action promptly, but no later than the next monitoring interval specified in § 192.465, or within 1 year, whichever is less. Additionally, new paragraph (f) proposed to add requirements for onshore gas transmission pipeline operators to perform CIS if annual test station readings indicate CP is below the level of protection required in subpart I. Unless it is impractical to do so, PHMSA proposed to require that operators complete CIS with the protective current interrupted. Whereas ACVG and DCVG are performed at the time of construction, before electrical current is on the pipe for CP, a CIS requires the pipe to be in the ground with the rectifiers installed. A CIS will discover areas of low current where CP might be weakened and can discover additional construction, operational or environmental damage along the pipeline when performed as a post-construction task. The NPRM's proposed revisions to § 192.465 would also require each operator to take remedial action to correct any deficiencies indicated by the CIS.

2. Summary of Public Comment

NAPSR and the PST generally agreed with and supported the revisions to § 192.465. NAPSR believed that the inclusion of a timeframe for operators to perform CIS and perform subsequent mitigation measures would increase pipeline safety but noted that PHMSA should provide further guidance on the intervals at which operators should perform the surveys. Both PST and NAPSR supported the revisions to appendix D.

Several industry entities commented on the proposed revisions to appendix D to part 192. INGAA stated that the proposed remaining criteria in appendix D for determining the adequacy of cathodic protection are too narrow, and that all industry standards provide for additional methods of assessing voltage drop. These commenters recommended that PHMSA follow the applicable paragraphs of NACE Standard Practice SP0169. Enterprise noted that appendix D should be consistent with § 195.571, which outlines the criteria that hazardous liquid pipeline operators must use when determining the adequacy of cathodic protection.

Commenters stated that the proposed changes to appendix D, as written, would apply to distribution pipelines as well as transmission pipelines and expressed concern that PHMSA has offered neither justification nor an estimate of the impact on distribution systems. These commenters requested that PHMSA clarify that the proposed changes to appendix D apply only to transmission pipelines.

Commenters, including committee members representing the industry during the meeting on June 6, 2017, stated that PHMSA should amend § 192.465 to include a more realistic timeframe for remedial action, specifically noting that the timeframe for remediation does not account for difficulties in obtaining the necessary permits. Additionally, commenters and GPAC committee members stated this provision could lead to unnecessary and costly work, as there are various situations that can produce a low CP reading that do not require CIS for the identification of the root cause. Those commenters stated there are certain conditions that do not require CIS and recommended allowing operators to identify, troubleshoot, and remediate these certain conditions on their own without the need to conduct CIS.

Further, GPAC members representing the industry disagreed with PHMSA's proposed revisions to the appendix D criteria for determining the adequacy of cathodic protection. Like their commentary on other provisions, these committee members also noted that the impact of these changes to distribution pipelines was not justified or analyzed, and therefore, distribution pipelines should be exempt from the proposed requirements.

Following their discussion, the committee voted 10–0 that the provisions related to the CP of steel, cast iron, and ductile pipelines were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that the new requirements in § 192.465(d) only apply to gas transmission pipelines and withdrew the proposed revisions to appendix D. The committee also recommended that PHMSA address situations where CIS may not be an effective response by instead requiring operators investigate and mitigate any non-systemic or location-specific causes of corrosion and require CIS if operators need to address systemic causes of corrosion. Additionally, the committee recommended PHMSA address its comments regarding the timeframe by which the proposed provisions would need to be completed by requiring operators make a remedial action plan and apply for any necessary permits within 6 months and finish the remedial action within 1 calendar year, not to exceed 15 months, or as soon as practicable once the operator obtains the necessary permits.

3. PHMSA Response

PHMSA intended that the amendments proposed in the NPRM would apply only to transmission pipelines and has, in this final rule, added the phrase ''onshore gas transmission pipelines'' to § 192.465(d)(1) of to clarify that limitation. PHMSA will consider expanding application beyond onshore gas transmission pipelines in the future. PHMSA believes that modifying the timeline for remediation is appropriate, and therefore, is requiring operators develop a remedial action plan and apply for the necessary permits within 6 months of the inspection, with the completion of remediation activities to be completed prior to the next monitoring interval or within 1 year, not to exceed 15 months. Like the previous section, such a change is consistent with both the GPAC recommendation on the issue and the timeframes for the related regulations in this final rule. PHMSA understands that, in almost all cases where an operator performs an excavation of 1,000 feet or more, that excavation will probably require some permits. An operator should obtain such permits in a manner to allow the performance of coating surveys and any necessary repairs to the coating.

In the NPRM, PHMSA proposed to update appendix D but did not intend to introduce any new requirements. PHMSA agrees with certain commenters that the proposed revisions could have unintended consequences by creating potential tension with analogous cathodic protection evaluation criteria in NACE Standard Practice SP0169 and § 195.571 governing hazardous liquid lines (which section incorporates NACE Standard Practice SP0169 by reference). However, as PHMSA did not propose incorporation by reference of NACE Standard Practice SP0169 in appendix D, PHMSA is withdrawing the proposed changes to appendix D. PHMSA will continue to examine appropriate evaluation criteria for catholic protection of gas transmission pipelines and may pursue future rulemaking on

this topic. These changes to the final rule for CP requirements are in accordance with the GPAC recommendations.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

vi. P&M Measures—§ 192.935(f) & (g)

1. Summary of PHMSA's Proposal

Currently, the gas transmission IM provisions do not explicitly address additional P&M measures for the threats of external and internal corrosion. For the same reasons that apply to the proposed changes for general corrosion control as discussed above, PHMSA proposed to address these gaps for HCAs. PHMSA determined that additional P&M measures are needed in § 192.935(f) and (g) to assure that public safety is enhanced in HCAs through additional protections from the time-dependent threats of internal and external corrosion. Specifically, PHMSA proposed to add § 192.935(f) and (g), which would require that operators enhance their corrosion control programs in HCAs to provide additional corrosion protections in addition to the proposed standards in subpart I. Under proposed § 192.935(f), operators would be required to enhance their internal corrosion management programs by performing mitigative actions if deleterious gas stream constituents are being transported and through performing semi-annual reviews of their programs.

Regarding the internal corrosion provisions discussed earlier in this document, § 192.477 prescribes requirements to monitor internal corrosion by coupon testing or other means if corrosive gas is being transported. However, the existing regulations do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, abnormal conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion because an operator's initial assessment did not identify the presence of corrosive gas. To provide additional protections for HCAs in addition to the standards proposed in subpart I, PHMSA proposed that § 192.935(f) would require operators use specific gas quality monitoring equipment for HCA segments, including but not limited to, a moisture analyzer, chromatograph, samplers for carbon dioxide, and samplers for hydrogen sulfide. The proposed provisions would also require operators sample at a certain frequency, use cleaning pigs to sample accumulated liquids and solids, and use corrosion inhibitors when corrosive constituents are present. PHMSA also proposed the maximum amounts of carbon dioxide, moisture content, and hydrogen sulfide that would require operator action.

Under proposed § 192.935(g), operators would also be required to enhance their external corrosion management programs, including controlling both alternating and direct electrical interference currents, confirming external corrosion control through indirect assessment, and controlling external corrosion through CP.

As described in the discussion on interference surveys above, interference currents can negate the effectiveness of CP systems. Section 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. In the NPRM, PHMSA proposed to amend § 192.473 to require that an operator's corrosion control program include interference surveys to detect the presence of interference currents and require the operator take remedial actions within 6 months of completing the survey. In HCAs, PHMSA proposed additional prescriptive requirements in § 192.935(g) to afford extra protections for HCAs, including a maximum interval of 7 years for an operator to perform interference surveys; more specificity regarding the survey performance, including technical acceptance criteria; and a requirement that pipe-to-soil test stations be located at half-mile intervals within each HCA segment with at least one station in each HCA, if practicable.

Lastly, PHMSA proposed to make conforming edits to appendix E, which provides guidance for P&M measures for HCA segments subject to subpart O. PHMSA proposed to accommodate the proposed revised definition for ''electrical survey'' by replacing that term with ''indirect assessment'' to accommodate other techniques in addition to CIS.

2. Summary of Public Comment

NAPSR and the PST agreed with and supported the proposed changes to the P&M measures for addressing internal and external corrosion in HCAs and suggested strengthening the proposed provisions further.

While trade associations and individual operators supported certain aspects of the proposed provisions covering the P&M measures addressing external corrosion and internal corrosion in HCAs, these commenters objected to the specific requirements in § 192.935. Many of these commenters stated a preference for allowing operators the flexibility to implement corrosion control based on their own judgment of the severity of the threat. In general, many industry commenters stated that individual sections of the proposed provisions were too broad and prescriptive, and pipeline operators would incur greater costs without justified benefit. Further, they stated that the monitoring frequency of twice per year was too frequent. Some commenters recommended that PHMSA reference ASME standards for implementing P&M measures, and other commenters stated concern that some of the proposed provisions are not consistent with NACE standards.

Many commenters objected to several of the proposed aspects of internal corrosion control, such as the identification of threats, monitoring, and filtering, and these commenters stated that operators should have flexibility in implementing P&M measures. For example, INGAA opposed the proposed requirement in § 192.935(f) that requires operators to install continuous gas quality monitoring equipment at all points in which gas with potentially deleterious contaminants enters the pipeline. INGAA recommended that § 192.935(f) apply only to pipeline segments with a history of internal corrosion and stated that this would be consistent with the required risk analysis that operators perform to determine whether P&M measures are necessary. Similarly, Atmos Energy recommended that gas sources be monitored only at those sources suspected, in the judgment of the operator, of having deleterious gas stream constituents, and that such monitoring can be performed in real-time or periodically. INGAA stated that PHMSA should modify proposed § 192.935(g) to require that operators conduct periodic indirect inspections only where a pipeline segment has a known history of corrosion.

During the GPAC meeting on June 6, 2017, committee members representing the industry reiterated that § 192.935(f) and (g) were too broad and prescriptive and should not apply to every HCA pipeline segment indiscriminately. These members, echoing comments made by INGAA, stated that operators should use their risk assessments to be used to determine which specific P&M measures are needed in accordance with the current IM approach.

The committee also suggested that PHMSA should reference specific ASME standards for P&M measures and ensure they are consistent with NACE

standards. Members representing the public suggested PHMSA review the proposed changes throughout subpart I and ensure that they would be as enforceable as the proposed P&M measures if the P&M measures were to be deleted. Members also discussed the fact that distribution operators do not always have gas monitoring equipment for their lines, as they depend on the suppliers to monitor the gas quality.

Following the discussion, the committee voted 9–1 (with a representative from PST dissenting) that the proposed rule, regarding the provisions for P&M measures for internal and external corrosion, were technically feasible, reasonable, cost-effective, and practicable if PHMSA withdrew the specific provisions discussed in § 192.935(f) and (g) and appendix E, as the requirements would have been duplicative with subpart I.

3. PHMSA Response

PHMSA noted during the GPAC meeting that it was persuaded by commenters that the changes it is making to the general corrosion control requirements in subpart I in this final rule are sufficient and that the additional regulations proposed in § 192.935(f) and (g) and appendix E were duplicative. The proposed changes to subpart I that PHMSA is finalizing in this rulemaking apply to pipelines in both HCAs and non-HCAs, and they were similar to the P&M measures that PHMSA was proposing regarding corrosion control in HCAs specifically. Therefore, PHMSA believes that the changes to subpart I in this rule provide the safety that the proposed changes at § 192.935(f) and (g) intended to provide. The proposed changes to appendix E incorporated the proposed definition for ''electrical survey'' and did not contain further substantive changes. After considering those comments, and as recommended by the GPAC, PHMSA is withdrawing all the proposed changes to § 192.935(f) and (g) and appendix E.

D. Inspections Following Extreme Weather Events—§ 192.613

1. Summary of PHMSA's Proposal

Weather events and natural disasters that can cause river scour, soil subsidence or ground movement may subject pipelines to additional external loads, which could cause a pipeline to fail. These conditions can pose a threat to the integrity of pipeline facilities if those threats are not promptly identified and mitigated. While the existing regulations provide for design standards that consider the load that may be imposed by geological forces, weather events and natural disasters can quickly impact the safe operation of a pipeline and have severe consequences if not mitigated and remediated as quickly as possible.

In the NPRM, PHMSA proposed revising § 192.613 to require that an operator inspect all potentially affected pipeline facilities after an extreme weather event to help ensure that no conditions exist that could adversely affect the safe operation of that pipeline. The operator would be required to consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the inspection required. The NPRM's proposed revisions to § 192.613 also provided that the initial inspection must occur within 72 hours after the cessation of the event, defined as the point in time when the affected area can be safely accessed by available personnel and equipment required to perform the inspection. If an operator finds an adverse condition, the NPRM' s proposed revisions to § 192.613 would require an operator to take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained because of performing the inspection.

2. Summary of Public Comment

The PST, NAPSR, and EnLink Midstream supported the proposed amendments to § 192.613, with many other stakeholders supporting the intent of the proposed provisions but requesting further clarification on some of the terms used within the proposal.

Some commenters expressed concern with the broad requirements of an ''inspection'' and requested PHMSA clarify what an inspection following an extreme weather event would entail. Additionally, these stakeholders stated that the proposed definition of an extreme weather event was vague and requested clarification. INGAA stated that operators are already required to have procedures to ensure a prompt and effective response to emergency conditions through § 192.615 and suggested that to avoid duplicative regulation, PHMSA should instead modify § 192.615(a)(3) to incorporate additional specificity on weather events that may trigger a response.

Many commenters objected to the proposed timeframe, stating that the 72-hour requirement listed in the rule could be problematic. Commenters stated that PHMSA should allow operators to determine when an impacted area can be safely accessed, and that pipeline operators are best positioned to evaluate the balance between the safety and the need for inspections to ensure continued safe operation of their systems. INGAA stated that the 72-hour requirement should either be replaced with a more general statement such as ''as soon as practicable,'' or that PHMSA should create a process to request an exception to the requirement. Louisiana Mid-Continent Oil and Gas Associations stated that extreme weather events vary significantly by region and commented that not all local geography and extreme weather events are the same. They further stated that the 72-hour deadline for inspection may be too prescriptive depending on the extreme weather event. They stated that because Louisiana is subjected to many unusual extraordinary events, such as spillway openings, high/low river flows, and rainwater flooding, PHMSA should clarify what ''other events'' means and how the cessation of an event is determined.

At the GPAC meeting of January 12, 2017, members noted concerns with the provisions as proposed but voted 12–0 that the provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA modified the proposed rule to clarify that the timing for this provision is to begin after the operator has made a reasonable determination that the area is safe, clarify in the preamble that operators are encouraged to consult with pipeline safety and public safety officials in order to make such determinations, delete the phrase ''whichever is sooner'' at the end of § 192.613(c)(2), and change the word ''infrastructure'' to ''facilities.''

3. PHMSA Response

PHMSA agrees that an operator's ability to inspect a pipeline facility following an extreme weather event may vary greatly depending on the type of extreme weather event that has taken place and the specific location of the event. The NPRM's proposed revisions to § 192.613 would require operators to inspect its pipeline facilities after the cessation of an extreme weather event. Cessation of the event was defined as the point of time when the affected area could be safely accessed by the personnel and equipment, including availability of personnel and equipment, required to perform the inspection. However, in consideration of the comments received, PHMSA is persuaded that additional clarification is warranted and that 72 hours after the cessation of the event may not be enough time in all cases for operator personnel and equipment to assess and inspect a pipeline safely.

Therefore, as recommended by the GPAC, PHMSA has modified this final rule to require an operator perform an initial inspection 72 hours after the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the necessary personnel and equipment required to perform such an inspection are available. PHMSA encourages operators to consult with pipeline and public safety officials, including the appropriate PHMSA regional office, when making these determinations. If an operator is unable to commence the inspection in the 72-hour timeframe due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

If an operator finds an adverse condition, the operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained from the inspection. Such actions might include, but are not limited to:

- Reducing the operating pressure or shutting down the pipeline;
- Isolating pipelines in affected areas and performing ''stand up'' leak tests;
- Modifying, repairing, or replacing any damaged pipeline facilities;
- Preventing, mitigating, or eliminating any unsafe conditions in the pipeline rights-of-way;
- Performing additional patrols, depth of cover surveys and adding cover over the pipeline, ILI or hydrostatic tests, or other inspections to confirm the condition of the pipeline and identify any imminent threats to the pipeline;
- Implementing emergency response activities with Federal, State, or local personnel; and
- Notifying affected communities of the steps that can be taken to ensure public safety.

PHMSA would not expect operators to comply with these provisions for weather or other disruptive events when, considering the physical characteristics, operating conditions, location, and prior history of the affected system, the event would not be expected to impact the integrity of the pipeline. For example, extreme weather events would not include rain events that do not exceed the high-water banks of the rivers, streams or beaches in proximity to the pipeline; rain events that do not result in a landslide in the area of the pipeline; storms that do not produce winds at tropical storm or hurricane level velocities; or earthquakes that do not cause soil movement in the area of the pipeline.

PHMSA is also modifying § 192.613(c) introductory text and (c)(1) as the GPAC recommended, by removing the phrase ''whichever is sooner'' and replacing the term ''infrastructure'' with ''facilities.'' As discussed during the GPAC meeting, ''pipeline facilities'' is a defined term at § 192.3, and the use of that term will likely provide additional clarity.

E. Strengthening Requirements for Assessment Methods—§§ 192.923(b) & (c), 192.927, 192.929

i. Internal Corrosion Direct Assessment (ICDA)—§§ 192.923(b) & 192.927

1. Summary of PHMSA's Proposal

The current regulations do not specify the quality and effectiveness of ICDA. NACE International submitted a petition for rulemaking on February 11, 2009, requesting that PHMSA address this issue. In the NPRM, PHMSA proposed amendments to §§ 192.923(b) and 192.927 to incorporate by reference NACE SP0206–2006 and further supplement the NACE standard to address issues observed by PHMSA.

For indirect inspections, PHMSA proposed to require that operators use pipeline-specific data, exclusively in performing an indirect inspection, and that the use of assumed pipeline or operational data would be prohibited. PHMSA also proposed operators be required to consider the accuracy, reliability, and uncertainty of data used to make calculations regarding the critical inclination angle of liquid holdup and the inclination profile of pipelines. Further, PHMSA proposed that operators be required to select locations for direct examination and establish the extent of pipe exposure needed, to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

For detailed examinations as defined in NACE SP0206–2006, PHMSA proposed to require that operators identify a minimum of two locations for excavation within each covered segment associated with the ICDA Region and perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques. One required location would be the low point within the covered segment nearest to the beginning of the ICDA Region. The second required location would be near the end of the ICDA Region within the covered segment. If corrosion was found at any location, the operator would be required to evaluate the severity of the defect, expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) with similar characteristics to the ICDA Region in the operator's pipeline system.

For post-assessment evaluation and monitoring, PHMSA proposed to require that operators evaluate the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those currently specified in the regulations at § 192.939. PHMSA also proposed to require that operators validate their flow modeling calculations by comparing locations of discovered internal corrosion with locations predicted by the model. Additionally, PHMSA proposed to require that operators continually monitor each ICDA Region that contains a covered segment where internal corrosion was identified and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products.

Finally, PHMSA proposed to require that operators include in their plans the criteria used in making key decisions in implementing each stage of the ICDA process and provisions that the analysis be carried out on the entire pipeline in which covered segments are present.

2. Summary of Public Comment

NAPSR expressed its agreement with, and support for, the proposed revisions to §§ 192.923(b) and 192.927. Multiple pipeline operators and industry trade associations commented that the proposed provisions should simply incorporate the NACE standard by reference, and should not exceed those established industry standards, be rigidly prescriptive, or otherwise be mandatory. PG&E, commenting on the incorporation of standards by reference, requested PHMSA replace the phrase ''as required by'' with ''in accordance with'' so that operators can meet the substantial requirement but have flexibility in the implementation of that requirement if the industry publishes new techniques to perform ICDA. NACE International expressed its belief that, as described in NACE SP0206–2006, ICDA is an acceptable standalone methodology for assessing pipeline integrity.

Atmos Energy commented that the proposed mandated monitoring for all ICDA regions would be potentially excessive and recommended that PHMSA delete the proposed language and restore the current language at

§ 192.927(c)(4)(ii).[29] Another commenter recommended that PHMSA remove the proposed notification requirement prior to an operator performing an ICDA, noting that operators currently provide this information as part of other annual reporting.

At the GPAC meeting on December 15, 2017, the GPAC committee voted, 13–0, to revise §§ 192.923(b)(2) and (3) and 192.927 according to the recommendations by PHMSA staff at the meeting, which included supplementing the NACE standard with additional requirements to address specific issues that could adversely affect ICDA results.

3. PHMSA Response

PHMSA believes that it is appropriate to address ICDA by incorporating by reference the NACE standard and supplementing it with additional requirements pertaining to indirect inspections (a step in the NACE standard's ICDA process to help in determining where direct assessments need to be made), detailed examinations, and post-assessments. For indirect inspections, PHMSA has implemented additional requirements regarding the data an operator must use and accounting for uncertainties in that data. Where an indirect inspection demonstrates that detailed examinations are needed, PHMSA is expanding the examinations that an operator must perform to evaluate for the potential for internal corrosion in all pipeline segments if corrosion is found in the ICDA region. Regarding post-assessments, PHMSA is requiring operators to evaluate the effectiveness of ICDA as an assessment method and determine whether a covered segment should be reassessed more frequently than the intervals specified at § 192.939. Additionally, PHMSA is requiring operators validate the flow modelling calculations they use in the ICDA process as well as continually monitor each ICDA region that contains a covered segment where internal corrosion has been identified.

When the first IM regulations were promulgated in the 2003 IM rule, there was no consensus industry standard for ICDA that could be adapted or incorporated into the regulations to promote better pipeline safety regarding internal corrosion. Incorporating by reference the NACE standard into the regulations would improve pipeline safety because the NACE standard (1) typically requires more direct examinations than the current regulatory requirements; (2) encompasses the entire pipeline segment and requires that all inputs and outputs be evaluated; and (3) is considered by many to be an equivalent or superior indirect inspection model compared to the Gas Technology Institute (GTI) model currently referenced in § 192.927. Its range of applicability with respect to operating pressure is greater than the GTI model, thus allowing the use of ICDA in pipelines with lower operating pressures and higher flow velocities.

The existing requirements in § 192.927 have one aspect that has proven problematic: the definition of regions and requirements for selection of direct examination locations in the regulations are tied to the covered segment. A ''covered segment'' is defined in § 192.903 as ''a segment of gas transmission pipeline located in a high consequence area.'' The terms ''gas'' and ''transmission line'' are defined in § 192.3. Therefore, covered segment boundaries are determined by population density and other consequence factors without regard to the orientation of the pipe and the presence of locations at which corrosive agents may be introduced or may collect and where internal corrosion would most likely be detected (*e.g.,* low spots). Section 192.927 requires that locations selected for excavation and detailed examination be within covered segments, meaning that the locations at which internal corrosion would most likely be detected may not be examined. Thus, the existing requirements do not always facilitate the discovery of internal corrosion that could affect covered segments. PHMSA is addressing this problem in this final rule by incorporating NACE SP0206–2006 and by expanding the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region.

PHMSA believes requiring a notification requirement for operators is important so that PHMSA can review the specific proposal to use a standard to assess pipe segments that are explicitly excluded from the scope of the standard. PHMSA has also revised § 192.927(c) to clarify that an operator must conduct the ICDA process ''in accordance with'' the NACE standard to avoid the implication that all non-mandatory recommendations contained in the standard are required.

E. Strengthening Requirements for Assessment Methods—§§ 192.923(b) & (c), 192.927, 192.929

ii. Stress Corrosion Cracking Direct Assessment (SCCDA)—§§ 192.923 & 192.929

1. Summary of PHMSA's Proposal

The current regulations do not specify a number of issues that affect the quality and effectiveness of SCCDA integrity assessments. Specifically, Appendix A3 of ASME/ANSI B31.8S, which is referenced in the regulations, provides some guidance for conducting SCCDA, but the guidance is limited to stress corrosion cracking (SCC) that occurs in high-pH environments. NACE International submitted a petition for rulemaking to PHMSA on February 11, 2009, requesting that PHMSA address this issue by incorporating by reference NACE SP0204–2008, which addresses near-neutral SCC in addition to high-pH SCC. Accordingly, in the NPRM, PHMSA proposed changes to §§ 192.923 and 192.929 to incorporate by reference NACE SP0204–2008 and supplement the NACE standard to address issues observed by PHMSA in the areas of data gathering and integration, indirect inspection, direct examinations, remediation and mitigation, and post-assessments.

PHMSA proposed to require an operator's SCCDA plan to evaluate the effects of a carbonate-bicarbonate environment; the effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments; the effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials; the effects of coatings that shield CP when disbonded from the pipe; and other factors that affect the mechanistic properties associated with SCC.

For indirect inspections, PHMSA proposed to require an operator's plan include provisions for conducting at least two above-ground surveys using complementary measurement tools most appropriate for the pipeline segment based on the data gathered.

For direct examinations, PHMSA proposed to require an operator's procedures provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

For post-assessments, PHMSA proposed to require that the operator's procedures include the development of a reassessment plan based on the

[29] PHMSA regulations at § 192.927(c)(2) define an ICDA region as a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline.

susceptibility of the operator's pipe to SCC as well as on the mechanistic behavior of identified cracking.

2. Summary of Public Comment

Multiple commenters supported the proposed changes to § 192.929 for SCCDA. NAPSR expressed its agreement with, and support of, these revisions. Spectra Energy Partners (SEP), which merged with Enbridge in 2017, provided comments in support of the proposed inclusion of explicit requirements for SCCDA. SEP expressed its belief that SCCDA is a diligent, practicable approach for assessments for SCC for cases where the pipeline has not previously experienced an in-service failure caused by SCC and provided specific edits to make the proposed requirements for SCCDA clearer and more practicable. A commenter recommended that the requirements for SCCDA specify that an operator is required to conduct assessments in areas that are most likely to be subject to SCC regardless of HCA designation.

Several other commenters questioned or opposed the proposed changes to § 192.929. Several commenters, including API, expressed their support of NACE standards SP0204–2008 for SCCDA but recommended that PHMSA not exceed those established industry standards and should not make the recommendations within those standards mandatory. NACE International stated it was unaware of any conclusive data regarding overprotection or high-negative potentials as a factor in SCC of pipelines, which is what the NPRM's proposed revisions to § 192.929 suggested. Additionally, NACE International commented that PHMSA went beyond the practices stated in NACE Standard SP0204–2008 by proposing to require a minimum of two above-ground surveys and three direct examinations.

INGAA proposed to clarify the way in which SCCDA can be used as an IM method, asserting that SCCDA is a valid method to assess SCC threats in gas pipeline segments that are susceptible to, but have no history of, SCC.

Other commenters provided specific technical comments regarding these proposed provisions. TransCanada asserted that applying the NACE ''significant SCC'' definition as the threshold for immediate repair is both overly conservative and overly complicated, and they suggested that PHMSA instead adopt the threshold of ''noteworthy'' as defined in ASME STP–PT–011.

Enable Midstream Partners (EMP) agreed that operators should consider the specific factors PHMSA proposed in § 192.929(b)(1) and (4) as part of the data gathering and integration and post-assessment remediation and mitigation process for SCCDA. However, EMP asserted that PHMSA should clarify these sections by including a referenced standard that provides guidance to operators on how they should consider these specific factors. Another commenter stated that PHMSA should include a reference to ASME/ANSI B31.8S, Appendix A3, for susceptibility criteria.

Commenters also suggested that PHMSA allow operators to use sound engineering judgments when calculating the remaining strength of the pipeline segment if the segment is subject to the pipeline material properties and attributes verification requirements of § 192.607 and those requirements have not yet been met.

At the GPAC meeting on December 15, 2017, the committee recommended PHMSA revise the approach proposed in the NPRM by making the changes to these provisions that were recommended by PHMSA staff during the meeting, which were to replace the spike hydrostatic pressure test requirements with a reference to § 192.506(e) to eliminate redundancy; address the gap pertaining to failure pressure calculations when data is not available; codify, as applicable, the expectation that the recommendations within the NACE standard are not mandatory; communicate additional guidance as needed during rule implementation; and consider how to structure the rule to apply results from non-HCAs to HCAs.

3. PHMSA Response

When the first IM rule was promulgated in 2003, there was no NACE standard for SCCDA. Additionally, the requirements pertaining to SCC in ASME/ANSI B31.8S, Appendix B, only applied to pipe susceptible to high pH SCC (*i.e.,* pipelines susceptible to near-neutral SCC were not addressed). Therefore, PHMSA believes that incorporating by reference the NACE standard and supplementing it with additional requirements to address issues it has observed related to data gathering and integration, indirect inspection, direct examinations, remediation and mitigation, and post-assessments, is an appropriate way to address SCCDA.

For data gathering and integration, PHMSA is requiring that operators gather and evaluate data related to SCC at all sites an operator excavates while conducting its pipeline operations where the criteria in NACE SP0204–2008 indicate the potential for SCC. Per this final rule, operators must additionally analyze the effects of a carbonate-bicarbonate environment, cyclic loading conditions, variations in applied CP, the effects of coatings that shield CP when disbonded from the pipe, and other factors that would affect the mechanics of SCC. For indirect inspections, PHMSA is requiring operators conduct at least two above-ground surveys using the measurement tools most appropriate for the pipeline segment based on an evaluation of the collected data. An operator's plan for direct examination must include a minimum of three direct examinations within the SCC segment at the locations where SCC would be most likely to occur. If an operator finds any indication of SCC in a segment, an operator must perform specific mitigation measures. Further, in this final rule, an operator must develop procedures for post-assessments based on the susceptibility of the pipeline segment to SCC as well as the mechanical behavior of identified cracking. Regarding EMP's comment stating that PHMSA should provide guidance to operators on how they should consider specific factors as a part of the data gathering and integration process by referring to a standard incorporated by reference within PHMSA regulations, as well as the comment recommending that PHMSA incorporate a reference to ASME/ANSI B31.8S, Appendix A3, for susceptibility criteria, PHMSA declines to incorporate by reference such standards because it could limit operators from considering all of the factors that they should.

PHMSA also agrees with commenters that referring to § 192.506, *Transmission lines: Spike hydrostatic pressure test,* in § 192.929 is preferred instead of repeating the spike hydrostatic test requirements and has changed this final rule accordingly. PHMSA addressed the comment about determining predicted failure pressure when needed data are not available by referencing § 192.712, which explicitly provides an operator with conservative assumptions and alternatives for material toughness values, material strength, and pipe dimensions and other data, in lieu of documented material properties.

F. Repair Criteria—§§ 192.714, 192.933

PHMSA identified several improvements to the IM repair criteria based on its experience gained since the IM rule became effective in 2004; ongoing research and development, including developments in ASME/ANSI B31.8S; and investigations into recent incidents. In the NPRM, PHMSA

proposed adjustments to the existing repair criteria for anomalies discovered in HCAs and proposed new repair criteria for anomalies found outside of HCAs.[30]

F. Repair Criteria—§§ 192.714, 192.933

i. Repair Criteria in HCAs—§ 192.933

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add more immediate repair conditions and more 1-year repair conditions for HCA pipeline segments in § 192.933. The specific anomalies and repair schedules for cracks, dents, and corrosion metal loss are discussed in their respective sections below. In certain cases, like for SCC and selective seam weld corrosion anomalies that were new to the repair criteria, PHMSA proposed to require that operators repair ''any indication of'' such anomalies. In other cases, such as for dents, PHMSA did not make significant changes to the existing repair criteria at § 192.933, which require the repair of ''any indication of'' metal loss, cracking, or a stress riser.

2. Summary of Public Comment

Public advocacy groups, including Pipeline Safety Coalition, the PST, and Clean Water for North Carolina, supported the proposed provisions that would strengthen the existing repair criteria at §§ 192.713 (non-HCAs) and 192.933 (HCAs). Additionally, NAPSR and the NTSB supported PHMSA's proposed repair criteria revisions.

There was common agreement from pipeline operators and the industry trade associations that the processes for HCA repairs and non-HCA repairs should be standardized. However, the trade associations and pipeline operators generally believed that the proposed provisions at §§ 192.713 and 192.933 were too prescriptive and would impede operators from performing repairs based on risks. They further stated that the proposed provisions do not take into consideration other factors that operators currently consider when optimizing plans to remediate anomalies, such as historical data, geography, and congestion of the right-of-way.

Some of the commenters representing the industry recommended PHMSA eliminate all references to the words ''any indication of'' within the proposed revisions to §§ 192.713 and 192.933 when applied to anomalies needing repair so that it is the confirmed presence of a condition that requires a repair instead. These commenters stated that requiring operators to repair an ''indication of'' certain anomalies would cause needless repairs and misallocate resources. Spectra Energy stated that PHMSA's annual report data indicates that only one repair is required for every three anomaly investigations, which demonstrates that the existing anomaly response criteria operators have implemented are appropriately conservative.

3. PHMSA Response

Based on PHMSA's annual report data, the number of immediate repairs have remained relatively constant even though the baseline assessment period has concluded. PHMSA understands that this is likely the result of operators deferring repair of non-immediate conditions until the defect progresses into an immediate repair condition, rather than immediate conditions arising spontaneously. PHMSA understands that most defects that become immediate repair conditions are observable by ILI equipment well in advance of progression to an immediate repair condition. The repair criteria in this final rule are intended to assure that anomalies are repaired before they become an immediate condition and are at or near failure. In this final rule, PHMSA has included reference to ASME/ANSI B31.8S within each of §§ 192.714 and 192.933 to take into consideration other factors that operators currently consider when establishing remediation plans.

In this final rule, PHMSA has removed the proposed repair criteria under §§ 192.714 (non-HCAs) and 192.933 (HCAs) for SCC and selective seam weld corrosion, which were new repair criteria that contained the phrase ''any indication of.'' PHMSA combined SCC and selective seam weld corrosion repair criteria into a more general cracking repair criteria because each of these phenomena is, or results in, cracking. PHMSA included remediation measures for SCC under the requirements at § 192.929, which are the requirements for using direct assessment for SCC but did not require the remediation of ''any indication of'' SCC. PHMSA was not proposing to change any of the existing repair criteria that referenced ''any indication of,'' such as that for dents with any indication of metal loss, cracking, or a stress riser. Those repair criteria remain unchanged in this final rule.

F. Repair Criteria—§§ 192.714, 192.933

ii. Repair Criteria in Non-HCAs—§ 192.714

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed at § 192.713 repair criteria for non-HCA areas to assure that operators promptly repair injurious defects that are discovered outside of HCAs. These proposed repair criteria for non-HCAs were based on, and were similar, to, the repair criteria (regarding structure, anomaly types, and the repair timeframes) for HCA pipeline segments proposed at § 192.933.

For those anomalies for which a 1-year response is required on HCA pipeline segments, PHMSA proposed that a 2-year response would be required in non-HCA pipeline segments. This proposal would require operators to remediate anomalous conditions on gas transmission pipeline segments promptly and commensurate with the risk they present, while allowing operators to allocate their resources to those anomalies in HCAs that present a higher risk.

The specific anomalies and repair schedules for cracks, dents, and corrosion metal loss are discussed in their respective sections below.

2. Summary of Public Comment

Citizen groups, including Pipeline Safety Coalition, the PST, and Clean Water for North Carolina, supported the proposed provisions that would strengthen the repair criteria for HCAs and non-HCAs. Additionally, NAPSR and the NTSB supported PHMSA's revisions to the repair criteria.

Generally, the industry trade associations and pipeline operators supported PHMSA's intention of establishing repair criteria outside of HCAs but disagreed with some of the specific provisions. There was common agreement, however, that the processes for HCA repairs and non-HCA repairs should be standardized.

The trade associations and pipeline operators generally believed that the proposed provisions were too prescriptive and would impede operators from performing repairs based on risks. They further stated that the proposed provisions do not take into consideration other factors that operators currently consider when optimizing plans to remediate anomalies, such as historical data, geography, and congestion of the right-of-way.

AGA recommended that PHMSA create a new subpart to address assessment requirements outside of

[30] The GPAC voted on each section of the repair criteria separately, and each section is discussed in more detail below.

HCAs and add a section within that subpart to cover repair criteria. Several other trade associations and pipeline operators echoed AGA's recommendations.

Several industry commenters also stated that the rulemaking did not demonstrate that the safety benefit of strengthened repair criteria outweighs the costs. Multiple operators stated that the proposed repair provisions in § 192.713 would increase the number of digs operators would need to perform and asserted that the increased number of digs may not improve pipeline safety.

Certain commenters suggested that it would not be appropriate for PHMSA to require operators to repair immediate conditions in non-HCAs before repairing immediate conditions in HCAs, and that PHMSA should require operators to prioritize those conditions discovered within HCAs if operators discover multiple immediate conditions in HCAs and non-HCAs simultaneously. More specifically, AGA requested that the rule explicitly prioritize immediate conditions within HCAs over immediate conditions in other locations when conditions are discovered simultaneously and recommended that PHMSA adopt different terminology for ''immediate repair conditions'' inside and outside HCAs. Similarly, other industry trade organizations expressed concern that the proposed provisions for non-HCAs would complicate the allocation of resources to HCAs on a higher-priority basis when confronted with the large number of new, non-HCA pipelines needing assessments.

Commenters also requested PHMSA make the sections pertaining to non-HCA repairs and HCA repairs consistent regarding pressure reductions. Commenters representing the industry noted that, as proposed, certain notification requirements for long-term pressure reductions or for those operators unable to respond within the given timeframe were different depending on whether the pipeline was in an HCA or a non-HCA. These commenters suggested that those notification procedures be made consistent, wherever possible, between the HCA and non-HCA repair criteria. Multiple trade associations and pipeline industry entities also expressed concerns that the proposed provisions requiring ''an operator to reduce the operating pressure of its affected pipeline until it can remediate the immediate repair conditions'' are unnecessarily conservative. INGAA asserted that the proposed pressure reduction requirements for non-HCAs are more stringent than the pressure reductions requirements for HCAs, and several commenters offered alternative methods for determining appropriate operating pressure reductions. Specifically, these commenters requested PHMSA allow operators to take a pressure reduction other than 80 percent if they documented the analysis performed and assumptions used. These commenters claimed that, as proposed in the NPRM, operators were allowed to use a different pressure reduction in HCAs if an analysis supported it but were not allowed to do so in non-HCAs.

During its meeting in late March 2018, the GPAC recommended PHMSA clarify that pressure reductions would be required for immediate conditions in non-HCAs and in cases where repair schedules could not be met. As a part of this recommendation, the GPAC also recommended that operators notify PHMSA when they could not meet the schedule for anomaly evaluation and remediation or when a temporary pressure reduction exceeds 365 days. The GPAC also recommended that PHMSA should allow operators to calculate pressure reductions (following the discovery of repairable conditions) by using either class location factors, or 80 percent of the operating pressure, or 1.1 times the predicted failure pressure. The GPAC also recommended PHMSA require that operators document and keep records, for 5 years, of the calculations and decisions used to determine such pressure reductions and the implementation of the actual reduced operating pressure. Further, the GPAC recommended PHMSA avoid duplicating language regarding the need for repairs and pressure reductions found in other sections of the regulations.

3. PHMSA Response

In the 2019 Gas Transmission Rule, PHMSA promulgated new requirements for operators to conduct integrity assessments in areas outside of HCAs, including all Class 3 and Class 4 locations and the newly defined ''moderate consequence areas'' (MCA) that are piggable. This new requirement was in response to the congressional mandate in the 2011 Pipeline Safety Act (Pub. L. 112–90) to expand IM or elements of IM beyond HCAs. The non-HCA repair criteria PHMSA is issuing in this final rule are the companion requirements to those assessments and are necessary to extend the assessment and repair program elements of IM effectively to areas beyond HCAs. Although PHMSA agrees that this requirement will likely result in additional repairs, PHMSA believes it is necessary and important to assure that injurious defects are remediated before they lead to loss of pipeline integrity.

Commenters requested that the non-HCA repair criteria be split out from the general non-IM repair provisions that previously existed in the regulations. PHMSA determined that the non-HCA repair criteria would be clearer and easier to comply with if they were in a distinct section, and PHMSA has created a new § 192.714 with all of the non-HCA repair criteria.

To the comments that suggested that a different schedule be created for immediate conditions within HCAs and non-HCAs, PHMSA believes that the existing approach used in subpart O for HCAs is better because the identification of anomalies based on ILI results is an actionable indication that there might be an injurious defect in the pipeline. Establishing repair criteria based on operators discovering these actionable anomalies assures that the anomaly is investigated promptly and repaired, if necessary. PHMSA believes it is prudent for an operator to perform any necessary repairs once the operator has excavated the pipe and exposed the anomaly for field investigation, instead of deferring the repairs. Although PHMSA agrees that defects in HCAs, if they were to fail, could result in higher consequences, PHMSA reminds readers that ASME/ANSI B31.8S, section 7.2, defines an immediate condition as an ''indication show[ing] that [a] defect is at failure point.'' PHMSA believes that any indication of a pipe that is at the point of failure needs to be addressed immediately, and as such, for both HCAs and non-HCAs, operators must reduce pressure and immediately remediate the anomaly.

PHMSA agrees with several commenters and the GPAC recommendations for consistently addressing pressure reductions for repairs for both HCA and non-HCA pipeline segments. PHMSA believes that pressure reductions are needed for immediate conditions and when repair schedules cannot be met and has incorporated pressure reductions for non-HCA pipelines that are like the existing requirements for HCAs in subpart O, which include the operator notifying PHMSA. PHMSA also agrees that the amount of the pressure reduction should be established to be 80 percent of the operating pressure at the time of discovery of the defect, or the predicted failure pressure divided by 1.1, or the predicted failure pressure times the design factor for the class location in which the affected pipeline is located, and that records for such pressure reductions must be kept for a minimum of 5 years. PHMSA

incorporated these provisions, as recommended by the GPAC, in § 192.714(e) for non-HCA pipelines. Further, PHMSA followed the GPAC recommendation for reducing duplicative language regarding repairs and pressure reductions and has streamlined this final rule accordingly.

PHMSA also notes that AGA suggested creating a new subpart for non-HCA assessments and repairs. Although PHMSA has not created a new subpart, PHMSA believes it has accomplished the same purpose by putting the new non-HCA assessment and repair requirements in separate, distinct sections.

F. Repair Criteria—§§ 192.714, 192.933

iii. Cracking Criteria—§§ 192.714(d)(1)(v) & 192.933(d)(1)(v)

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add criteria to address cracking and crack-like defects, including SCC, because the existing regulations have no explicit repair criteria for those types of critical defects. The cracking criteria would apply to both HCAs and non-HCAs, but they would require repair at different size thresholds and at different timeframes depending on the anomaly location.

Following the Enbridge incident near Marshall, MI, the NTSB recommended that PHMSA revise the hazardous liquid regulations at § 195.452 to state clearly: (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or SCC as applicable.[31] Although the recommendation was limited to hazardous liquid pipelines, the issue applies equally to gas transmission pipelines, as SCC can occur on these pipelines as well.

Therefore, in the NPRM, PHMSA proposed to allow operators to use an engineering critical assessment (ECA) to evaluate indications of SCC. If the SCC was ''significant,'' it would be categorized as an ''immediate'' repair condition. If the SCC was not ''significant,'' it would be categorized as a ''1-year'' condition. Further, PHMSA proposed to adopt the definition of significant SCC from the consensus industry standard NACE SP0204–2008. PHMSA also proposed that an operator could not use an ECA to justify not remediating any known indications of SCC.

The current regulations also do not have repair criteria for seam cracks or crack-like flaws. Current regulations also fail to address corrosion affecting a longitudinal seam and selective seam weld corrosion, which are time-sensitive integrity threats that behave like cracks and are categorized as crack-like defects. In the NPRM, PHMSA proposed to address these gaps by including repair criteria for cracks and crack-like flaws in § 192.933 and proposed similar criteria in § 192.713.

2. Summary of Public Comment

INGAA, API, and Piedmont strongly opposed the proposed provisions in § 192.713(d)(1)(v), that stated ''any indication of significant SCC'' constitutes an immediate repair condition. Commenters requested that PHMSA determine the repair condition of cracks and crack-like defects according to factors that capture the severity of the defect, such as predicted failure pressures or maximum depth. Many commenters believed that PHMSA's proposed criteria were too conservative and suggested the repair criteria be for anomalies with a crack depth of greater than 70 percent of the pipe wall thickness or with a predicted failure pressure of less than 1.1 times MAOP. Other commenters suggested PHMSA delete the definitions of specific significant crack defects and use the alternative cracking criterion proposed by PHMSA at the GPAC meeting on March 2, 2018.

INGAA recommended making the repair criteria for cracking consistent with the repair criteria for metal loss and suggested that PHMSA consider anomalies with a crack depth of 80 percent wall thickness as immediate conditions for this reason. INGAA also recommended that PHMSA adopt a failure pressure ratio approach for cracking.

Certain commenters noted that the classification of all cracks or crack-like defects as 2-year repair conditions was overly conservative and suggested PHMSA relax that requirement. For example, some commenters suggested requiring repairs at 50 percent crack depth or a predicted failure pressure of less than 1.25 times MAOP.

At the GPAC meeting, for the proposed repair criteria for cracks, members representing the industry stated PHMSA's criteria for the immediate repair of certain crack defects were too conservative and suggested establishing an immediate repair threshold for cracks up to 70 percent of wall thickness or those with a predicted failure pressure of less than 1.1 times MAOP rather than those cracks with a predicted failure pressure of less than 1.25 times MAOP. Members representing the public noted that public safety would be better served by the threshold for immediate crack repairs being more conservative but questioned whether the more stringent threshold would be practical.

Similarly, members representing the industry suggested that PHMSA's proposed criteria for 1-year and 2-year scheduled conditions were too conservative as well and suggested setting the relevant criteria as those cracks with a depth of 50 percent wall thickness or those cracks with a predicted failure pressure of less than 1.25 times MAOP. Members representing the industry also suggested that, in addition to relaxing the criteria for immediate cracks, PHMSA should also add language requiring operators to consider tool tolerance and other factors when examining crack growth rates. Further, members representing the industry suggested that PHMSA base the repair criteria on design conditions or design factors rather than class location factors. Committee members also suggested that PHMSA cross-reference specific regulatory language rather than repeat the text in full in other sections of the code.

Following the discussion, the committee voted 12–0 that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for cracking repair criteria were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) struck the proposed definitions of ''significant seam cracking'' and ''significant stress corrosion cracking,'' (2) deleted the phrase ''any indication of'' from the repair criteria related to cracking, (3) combined the criteria for SCC and seam cracking, (4) required that operators calculate predicted failure pressures for all time-dependent cracking anomalies by using the fracture mechanics

[31] NTSB Recommendation P–12–3, available at *https://www.ntsb.gov/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-003.*

procedure PHMSA developed, (5) revised the definition of ''hard spot'' as discussed,[32] and (6) considered specific crack repair criteria as immediate conditions. Those specific crack repair criteria for immediate conditions would include (1) crack depth plus corrosion greater than 50 percent of pipe wall thickness; (2) crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or (3) the crack anomaly is determined to have a predicted failure pressure that is less than 1.25 times MAOP.

3. PHMSA Response

In this final rule, PHMSA did not adopt the proposed definitions of ''significant seam cracking'' and ''significant stress corrosion cracking.'' With the revisions to the cracking repair criteria, these definitions weren't necessary. Similarly, with the deletion of the proposed repair criteria using those specific definitions, the recommendation for deleting the phrase ''any indication of'' from those criteria, became moot. Further, PHMSA's revisions to the cracking repair criteria also made the recommendation for PHMSA to combine the proposed SCC criteria and the seam cracking criteria moot.

PHMSA believes that the repair criteria it proposed in the NPRM for cracks are consistent with research findings and provides an adequate safety margin while accounting for the severity of the defects through the analysis of the predicted failure pressure.[33] PHMSA believes the repair criteria for cracks that were suggested by some of the commenters would not provide an adequate safety margin due to factors including the accuracy of tool results, varying pipe toughness, and pressure cycling. This was discussed at length by the GPAC, who ultimately recommended that anomalies be classified as immediate conditions where the crack depth plus corrosion is greater than 50 percent of pipe wall thickness, compared to certain commenters who suggested that cracks with a depth of up to 70 percent pipe wall thickness be classified as immediate conditions.

While the GPAC did not have an explicit recommendation for scheduled (*i.e.,* non-immediate) crack repair criteria, they recommended that PHMSA consider a repair schedule for cracks that is less conservative than what was proposed in the NPRM. Their recommended schedule is: 1.39 times MAOP for Class 1 and 2 locations and 1.5 times MAOP for Class 3 and 4 locations. PHMSA considered this recommendation and determined that the condition should cover Class 1 locations and Class 2 locations containing Class 1 pipe that has been uprated in accordance with § 192.611, where the predicted failure pressure is 1.39 times MAOP. For all other Class 2 locations and higher class locations, the predicted failure pressure would be 1.5 times MAOP. Section 192.611 allows Class 1 pipe to remain in a Class 2 location if it has had a subpart J pressure test, for 8 hours, at 1.25 times MAOP. Also, it allows pipe with a design factor of 0.72, with the reciprocal of 1 divided by 0.72 being equal to 1.39, which is the predicted failure pressure. Therefore, PHMSA elected to apply a predicted failure pressure ratio of 1.39 times MAOP to both Class 1 pipe and uprated Class 2 pipe.

For immediate conditions, the GPAC asked PHMSA to consider if a less conservative repair criterion of 1.1 times MAOP (after tool tolerance had been applied) would be appropriate. PHMSA considered this suggestion but notes that, after allowing for pressure excursions above MAOP due to over pressure protection device settings, the actual safety margin of such an approach would be between 0 and 6 percent. PHMSA has determined that this safety margin for immediate crack conditions is inadequate and, for this final rule, has retained the requirement that operators must immediately repair crack anomalies with a predicted failure pressure that is less than 1.25 times MAOP.

PHMSA took technical guidance information from several sources into account regarding significant SCC and significant seam weld corrosion when creating the repair criteria for these anomalies, including ASME ST–PT–011 (''Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'').[34]

ASME ST–PT–011 states that stress corrosion cracks are ''Noteworthy'' if the maximum crack depth is greater than 10 percent of the wall thickness and if the maximum interacting crack length is more than the critical length of a 50 percent through-wall crack at a stress level of 110 percent SMYS.[35] The report provides categories as follows:

Category 1: Predicted Failure Pressure (PFP) is above 110 percent SMYS (note that 110 percent SMYS is used to delineate Category 1 cracks because it corresponds to the pressure most commonly prescribed for hydrostatic testing).

Category 2: PFP is above 125 percent MAOP[36] and below 110 percent SMYS.

Category 3: PFP is above 110 percent MAOP and below 125 percent MAOP.

Category 4: PFP is below 110 percent MAOP.

Category Zero: A crack below the threshold for Noteworthy cracks. These typically fall into two groups: (1) Those that are shallow (*i.e.,* less than 10 percent through-wall depth), or (2) Those that are so short that, even if they were 50 percent through-wall depth, they would not result in a hydrostatic test failure.

In this final rule, operators can use an engineering analysis on cracks in Categories 1 through 2 as described above. However, any Category 3 or 4 cracking defect below 125 percent MAOP would require immediate remediation. Category 3 cracks would have a 10 percent or greater safety factor, which is similar to how PHMSA currently treats corrosion anomalies at § 192.933. PHMSA provides more conservatism in the cracking criteria because there is more uncertainty with the accuracy of current ILI technology in its ability to measure crack length and depth, as well operational factors.

These severity categories allow operators to estimate the minimum remaining life at operating pressure for each category. The following estimates from ASME ST–PT–011 are based on the time it would take for the crack depth to increase to a failure-causing depth at the operating pressure. For pipelines operating at 72 percent SMYS, the following minimum operational lives for each category of cracks are as follows:

[32] This is discussed more under the ''Definitions'' subsection of this section.

[33] See ASME, ''STP–PT–0011:Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (2008). See also Young, B.A., et al., ''Comprehensive Study to Understand Longitudinal ERW Seam Failures'' (2017), available at *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.* Both papers call for anomaly evaluation; the knowledge of certain properties, including the length and depth of the crack, and pipe properties like wall thickness, grade, and toughness; and a proposed safety factor based on the time until the next assessment period. The papers also require that the depth of a crack not be greater than the depth of the assessment tool's tolerance. See § 192.712(e).

[34] ASME, ''STP–PT–011: Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (2008).

[35] PHMSA notes that 110 percent SMYS for a Class 1 pipeline is roughly equivalent to 1.49 times MAOP.

[36] PHMSA notes that 125% times MAOP for a pipeline that operates at 72% SMYS in a Class 1 location would correspond to roughly 90% SMYS for a Category 2 crack. PHMSA has defined in § 192.506 that a spike test for cracking should be conducted at a pressure of 100 percent of SMYS (roughly equivalent to 1.39 times MAOP for a Class 1 location) or 1.5 times MAOP.

Category Zero: Failure life exceeds 15 years (for short cracks) to 25 years (for shallow cracks).

Category 1: Failure life exceeds 10 years.

Category 2: Failure life exceeds 5 years.

Category 3: Failure life exceeds 2 years.

Category 4: Failure may be imminent.

ASME ST–PT–011 further states that mitigating a pipeline segment with SCC should be commensurate with the severity of the discovered crack, which would reflect the PFP and the estimated life at the operating pressure. For example, Category Zero cracks may warrant no more than ongoing SCC condition monitoring and reassessment after a period of 7 years. Cracks may be best assessed by direct assessment, hydrostatic testing, or ILI. The most severe cases would require an immediate pressure reduction, repair (if the location is known), and hydrostatic testing or ILI, followed by replacing the pipe or installing an appropriate sleeve over the crack or known cracking areas.

F. Repair Criteria—§§ 192.714, 192.933

iv. Dent Criteria—§§ 192.714 & 192.933

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed that dents in non-HCA segments with any indication of metal loss, cracking, or a stress riser would be considered ''immediate'' repair conditions. Additionally, PHMSA proposed that dents meeting the ''1-year'' repair conditions under § 192.933 would be required to be repaired in non-HCAs within 2 years.

2. Summary of Public Comment

Multiple commenters, including the industry trade associations and operators, disagreed that all dents with metal loss should be considered immediate repair conditions. These commenters requested that PHMSA's final rule address different kinds of dents separately. Many pipeline operators stated that dents with metal loss from ''scratches, gouges, and grooves'' are appropriate as immediate repair conditions, while dents caused by corrosion are lower risk and should be conditions scheduled for later repair. Several organizations cited API Publication 1156 [37] and ASME/ANSI B31.8, ''Gas Transmission and Distribution Piping Systems,'' to support these claims. Several commenters also recommended that PHMSA impose different response timelines for dents depending on the location and the manner of the dents, because dents with bottom-side metal loss are usually corrosion-related and low-risk, while dents on the top of the pipeline with metal loss are likely to be from mechanical damage and are at a higher risk to fail. This distinction would be consistent with the criteria for smooth dents (dents with no peaks, buckling, gouging, cracking, or metal loss that can reduce the operational life of the pipe).

With further regard to the repair criteria for dents, commenters representing the industry believed PHMSA should allow operators to use an ECA to evaluate dents as an alternative to following the prescribed repair criteria. Some of this discussion focused on whether PHMSA should include a finite element analysis (FEA) [38] as part of the ECA and whether PHMSA should define critical strain levels as a criterion in the ECA. Comments from industry additionally suggested that the criterion related to gouges or grooves greater than 12.5 percent of wall thickness was duplicative with other criteria. Industry trade associations noted that gouges and grooves would be evaluated in accordance with the dent, metal loss, or cracking criteria, and therefore, a separate anomaly category for gouges and grooves should be removed. Further, they asserted that current ILI technology can't determine the specific cause of metal loss, which would make this criterion unfeasible.

At the GPAC meeting on March 26, 2018, the committee recommended changes to several of the specific repair criteria for cracks, corrosion metal loss, and dents. Specific to dents, the committee recommended that PHMSA allow use of an ECA to evaluate certain dent-related anomalies and incorporate the ECA into the repair criteria.[39]

Following the discussion, the committee voted 12–0 that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for dent repair criteria were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) allowed operators to use an ECA for specific dent-related repair criteria and considered language to accommodate alternative ECA methods (including an FEA), and (2) distinguished between top-side dents that exceeded critical strain levels and bottom-side dents that exceeded critical strain levels by making distinct criteria for those anomalies.

3. PHMSA Response

PHMSA believes that the repair criteria it proposed in the NPRM for dents provide an adequate safety margin and believes the criteria for dents that were suggested by some of the commenters would not provide adequate safety margin. PHMSA based this judgment on R&D programs that have been sponsored by PHMSA and the Pipeline Research Council International, and on elements of dent repair criteria that are contained within API RP 1183.[40]

PHMSA agrees with the GPAC recommendation for allowing an ECA method to evaluate dent anomalies and has revised the dent repair criteria for immediate, scheduled, and monitored conditions, as recommended by GPAC, to do so. PHMSA believes that the development of high-resolution deformation ILI tools has advanced enough to justify allowing operators to use an ECA method to evaluate dent anomalies and believes that it would be consistent with public safety while providing operators additional flexibility. While this rulemaking was under development, API published API RP 1183, which provides guidance for assessing and managing dents that are present in pipeline systems as a result of contact by rocks, machinery, or other forces. The RP presents guidance for developing a dent assessment and management program by (1) providing suitable methods for inspecting and characterizing the condition of the pipeline with respect to dents; (2) establishing data screening processes to evaluate dents relative to the extent and degree of deformation and operational severity; (3) providing response criteria for dents based on the dent shape and profile as determined by ILI; (4) applying engineering assessment methods to evaluate the fitness-for-service of dents, including the reassessment interval; (5) presenting remediation and repair options to address dents; and (6) developing preventive and mitigative measures for dents in lieu of, or in addition to,

[37] API, ''Pub. 1156: Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines'' (1997).

[38] FEA is a modeling technique used to find and solve structural or integrity issues for phenomena such as cracking or denting. Pipe properties, including the parameters of the damage to the pipe, planned operating pressure, lifespan until the next evaluation, and any future operational conditions (max pressure, pressure cycle, higher temperatures), are needed to perform an FEA.

[39] Many of the recommended changes to the proposed repair criteria were highly technical in nature. For more information, including transcripts of the discussion and the voting slides, please visit: *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=132.*

[40] API, Recommended Practice 1183, ''Assessment and Management of Dents in Pipelines'' (Nov. 2020).

Exhibit TRA-3

periodic dent integrity assessment, including pressure reductions and pressure cycle management.

PHMSA agrees with commenters that the criteria based on gouges and grooves would be duplicative with other criteria being proposed in the NPRM, namely the criteria related to metal loss anomalies. Accordingly, PHMSA has removed the criteria related to gouges and grooves from this final rule.

In the 2019 Gas Transmission Rule, PHMSA finalized an ECA method for operators to use as a part of the pipeline material property and attribute verification under § 192.607 and the MAOP reconfirmation requirements of § 192.624. A key aspect of that ECA method is the detailed analysis of the remaining strength of pipe with known or assumed defects. The 2019 Gas Transmission Rule created a new section, § 192.712, to address the techniques and procedures an operator could use to analyze the predicted failure pressures for pipe with corrosion metal loss and cracks or crack-like defects.[41] That analysis requires the conservative analysis of the defect to determine the remaining life of the pipeline. In this final rule, PHMSA is building on the provisions it promulgated in the 2019 Gas Transmission Rule by allowing operators to use such an analysis for determining the timing of certain anomaly repairs, including dents. Unlike the previously existing repair criteria, which required the repair of listed anomalies within a specific timeframe, operators, per this final rule, can perform this analysis to determine whether the predicted failure pressure of the anomaly would warrant additional monitoring and a later repair. PHMSA understands that operators may propose, for PHMSA review in accordance with § 192.18, procedures for the assessment and remediation of dent anomalies (such as an ECA for dent anomalies); operators may develop those procedures using consensus industry standards (*e.g.,* API RP 1183, ASME B31.8, ASME B31.8S) or current research findings.

F. Repair Criteria—§§ 192.714, 192.933

v. Corrosion Metal Loss Criteria—§§ 192.714 & 192.933

1. Summary of PHMSA's Proposal

The required remediation of several types of corrosion defects that are incorporated in the hazardous liquid regulations in part 195 are currently omitted from part 192. The current gas transmission IM regulations allow operators to use ASME/ANSI B31.8S, Figure 4, for guiding repair decisions not specified in § 192.933(d), which can allow operators significant discretion in assessing and remediating pipe with corrosion or metal loss defects. PHMSA has found a wide variation in operators' interpretation of how to meet the requirements of the regulations in assessing, evaluating, and remediating corrosion and metal loss defects.

To address these gaps, and to harmonize part 192 with part 195, PHMSA proposed to amend § 192.933 to designate as immediate repair conditions those anomalies where metal loss is greater than 80 percent of nominal wall thickness and for indications of metal loss affecting certain legacy pipe with longitudinal seams.

To address gaps related to non-immediate conditions, the NPRM proposed that operators must repair the following within 1 year: (1) anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 times the MAOP for Class 1 locations, 1.39 times the MAOP for Class 2 locations, 1.67 times the MAOP for Class 3 locations, and 2.00 times the MAOP for Class 4 locations (comparable to the alternative design factor specified in § 192.620(a)); (2) areas of general corrosion with a predicted metal loss greater than 50 percent of nominal wall thickness; (3) anomalies with predicted metal loss greater than 50 percent of nominal wall thickness that are located at crossings of another pipeline, are in areas with widespread circumferential corrosion, or are in areas that could affect a girth weld; and (4) anomalies with metal loss due to gouges or grooves[42] that are greater than 12.5 percent of nominal wall thickness.

2. Summary of Public Comment

A commenter noted that PHMSA should recognize that gouges and scrapes are metal loss defects that can be smoothed by grinding to eliminate stress concentrations.

Multiple commenters also provided input on the proposed provisions that determine repair criteria for metal loss affecting certain pipe with longitudinal seams. INGAA, AGA, and a pipeline industry entity generally supported a classification of ''immediate'' for anomalies with ''an indication of metal loss affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency or high frequency electric resistance welding or by electric flash welding.'' However, PG&E requested that PHMSA not classify metal loss affecting a detected longitudinal seam as an immediate repair condition if that seam was formed by high-frequency electric resistance welding, as that pipe is considered ductile. National Fuel requested that PHMSA categorize longitudinal seam metal loss based on a minimum metal-loss threshold rather than ''an indication.'' Certain commenters requested PHMSA allow operators to perform a fitness-for-service evaluation or ECA on selective seam weld corrosion.

Kern River suggested PHMSA should consider applicable manufacturing and tool detection tolerances in the establishment of repair criteria that require response to ''any indication of metal loss.''

Several commenters, including AGA, Pauite, and DTE, did not support the proposed inclusion of ''any indication of significant seam weld corrosion'' in § 192.713(d)(1)(vi). INGAA and AGA asserted that seam weld corrosion can only be conclusively determined by an in-field examination even though ILI tools are often employed to identify possible seam weld corrosion areas.

INGAA requested that gouge and groove metal loss anomalies be deleted from the 1-year and 2-year response conditions. Other commenters noted that current ILI tools do not have the capability of differentiating 12.5 percent gouge or groove metal loss anomalies from 12.5 percent external corrosion metal loss anomalies and suggested PHMSA delete this proposed requirement. These commenters argued that, given current ILI technology and per this proposal, operators would be required to investigate all metal loss indications greater than 12.5 percent to determine if the metal loss was a gouge or groove. Several trade associations and pipeline industry entities requested that operators be allowed to perform excavations to validate ILI results before classifying a segment as a high-priority repair.

Several pipeline industry commenters disagreed with the proposed repair criteria and repair methods that differed from industry standard ASME/ANSI B31.8S. For example, AGA stated that they opposed the inclusion of different repair criteria for different class locations because this contradicts ASME/ANSI B31.8S. API noted that PHMSA's proposal contradicted the ASME/ANSI standard by including depth-based criteria and also stated that PHMSA should not include the depth-

[41] See 84 FR 52236, 52237.

[42] Gouges or grooves are stress concentrators that lead to cracking and fatigue, which in turn may lead to accelerated failure.

based criteria but only reference ASME/ANSI B31.8S, which is considered the best accepted practice. Similarly, INGAA recommended that PHMSA allow operators to use the repair methods in ASME/ANSI B31.8S rather than the proposed criteria.

Some commenters thought that the new proposed criteria for corrosion anomalies made the existing corrosion repair requirements at § 192.485(c) duplicative and requested PHMSA delete the existing corrosion repair requirements for clarity. Other commenters noted that PHMSA's proposed requirement for corrosion greater than 50 percent of wall thickness was redundant to other proposed corrosion metal loss defects and suggested this specific item should be deleted. Similarly, commenters suggested that the criteria for predicted metal loss greater than 50 percent of nominal wall located at the crossing of another pipeline, areas with widespread circumferential corrosion, or areas that could affect a girth weld were both too conservative and duplicative of other corrosion repair criteria.

At the GPAC meeting on March 26, 2018, regarding the general provisions and applicability of the corrosion metal loss repair criteria, commenters representing the industry noted that for 1-year and 2-year scheduled conditions, the use of class location safety factors would be burdensome, as it would require more frequent repairs for pipelines in Class 2, Class 3, or Class 4 locations than contemplated by consensus industry standard ASME/ANSI B31.8S section 7, figure 4.

The committee also discussed specific requirements related to the repair of corrosion anomalies. Echoing many of the public comments on the topic, members representing the industry believed that the newly proposed corrosion repair requirements were either overly conservative or duplicative compared to existing repair requirements in the corrosion control subpart. These committee members suggested the new requirements should be deleted or otherwise changed to be less conservative. Additionally, these members noted that the proposed criteria for anomalies where corrosion is greater than 50 percent of wall thickness would be redundant with other repair criteria for evaluating corrosion metal loss defects using accepted analysis techniques, such as ASME B31G and remaining strength of corroded pipe (RSTRENG).[43] Further, for corrosion metal loss affecting pipe seams, members representing the industry suggested the criteria should apply to corrosion that ''preferentially'' affects the long seam,[44] and that PHMSA should allow an ECA to analyze such defects to prevent unnecessary excavations.

The committee also suggested that PHMSA evaluate predicted failure pressure ratings and thresholds for remediation schedules of anomalies at pipeline crossings with widespread circumferential corrosion or with corrosion that can affect a girth weld.

Following the discussion, the committee voted 11–0 that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for corrosion metal loss repair criteria (excluding the repair timing) were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) clarified that the criteria do not apply to corrosion pits near a long seam but does apply to corrosion along seams that could lead to slotting-type crack-like defects, (2) deleted duplicative criteria, (3) cross-referenced the proposed new fracture mechanics section with the general corrosion remediation requirements, and (4) revised the repair criteria for scheduled conditions regarding the predicted failure pressure as discussed by the committee.

The committee then voted 8–3 (with each of two members representing State regulators and one member representing the public dissenting) that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for scheduled conditions regarding the predicted failure pressure repair criteria for corrosion metal loss anomalies were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) incorporated ASME/ANSI B31.8S, section 7, figure 4, into the repair criteria; (2) required operators to consider ILI tool tolerance on all runs; (3) removed and revised the predicted failure pressure standards for metal loss anomalies per the discussion of the committee; and (4) provided guidance to improve the understanding and use of ASME/ANSI B31.8S, section 7, figure 4.

For corrosion metal loss anomalies that meet the ''scheduled'' criteria (*i.e.,* 1-year conditions for HCAs and 2-year conditions for non-HCAs), the GPAC voted 8–3 that PHMSA should remove the predicted failure pressure standards for Class 1 and Class 2 segments from the NPRM and require operators to use section 7, figure 4 from ASME/ANSI B31.8S instead (*i.e.,* retain the current requirement in place for HCAs under subpart O).

3. PHMSA Response

When developing the repair criteria in the NPRM, PHMSA evaluated grounding the predicted failure pressure for those criteria in one or more of the following three factors: (1) the test pressure of a pipeline, (2) the design factor of a pipeline, and (3) the HCA repair criteria. Because PHMSA sought to improve upon existing HCA repair criteria, PHMSA decided against using that factor as the basis for calculating predicted failure pressures and proposed using test pressure or design factor of a pipeline instead. PHMSA based its proposed threshold for Class 1 pipelines (less than or equal to 1.25 times MAOP predicted failure pressure) on the maximum test pressure in § 192.619 for Class 1 pipelines (1.25 times MAOP). For the repair thresholds for Class 2, Class 3, and Class 4 pipelines, PHMSA calculated predicted failure pressures using the reciprocals of the design factors listed at § 192.111 for the immediately preceding class location rating. This approach ensured an adequate margin to failure even if the pipeline were to experience a one-class bump (pursuant to § 192.611) from changes in population density of the surrounding area. The resulting predicted failure pressure thresholds were less than or equal to 1.39 times MAOP (reciprocal of the 0.72 Class 1 design factor) for pipelines in a Class 2 location, less than or equal to 1.67 times MAOP for pipelines in Class 3 locations, and less than or equal to 2.00 times MAOP for pipelines in Class 4 locations.

PHMSA believes the repair criteria for corrosion metal loss that were suggested by some of the commenters would not provide adequate safety margin compared to what PHMSA proposed in the NPRM. This was discussed at length by the GPAC, who recommended repair criteria that, in some cases, were less conservative than what PHMSA proposed in the NPRM.

In this final rule, PHMSA adopted the GPAC's recommendation to incorporate ASME/ANSI B31.8S section 7, figure 4, into the repair criteria by requiring operators to use it in Class 1 locations for metal loss anomalies with a

[43] Both are incorporated by reference at § 192.7; see (c)(4): ASME/ANSI B31G–1991 (Reaffirmed 2004), ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' 2004, and (j)(1): AGA, Pipeline Research Committee Project, PR–3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' (December 22, 1989).

[44] Corrosion that ''preferentially'' affects the long seam is corrosion that is of and along the weld seam that is classified as selective seam weld corrosion. It normally effects low frequency electric resistance weld seams (LF–ERW) and electric flash welded seams (EFW).

predicted failure pressure greater than 1.1 times MAOP, which is consistent with the previous IM repair regulations. The committee also recommended PHMSA provide additional guidance on the use of ASME/ANSI B31.8S section 7, figure 4. ASME/ANSI B31.8S, section 7, figure 4 has three scales for repair that are based on the MAOP of the pipeline and the MAOP's percentage of the pipeline's SMYS.[45] Operators can use one of the 3 sliding scales of figure 4, as appropriate, to address anomalies when the anomaly has a failure pressure ratio above 1.1. As discussed previously, operators are currently required to follow ASME/ANSI B31.8S section 7, figure 4 under elements of the previous IM repair regulations. PHMSA understands that the 10 percent nominal safety margin provided by compliance with ASME/ANSI B31.8S section 7, figure 4 is appropriate for the relatively low risk to public safety posed to pipelines in low-population-density, Class 1 locations.

However, PHMSA did not accept the GPAC's recommendation for Class 2 locations. The number of immediate repair conditions being discovered during reassessments in Class 2 locations continues at approximately the same rate as they were discovered during the baseline assessment phase of the IM rule promulgated in 2004, according to PHMSA annual report data. PHMSA attributes this to defects that are not repaired and allowed to grow to a size that are at or near failure (*i.e.,* an immediate condition). Existing immediate repair criteria for pipelines in Class 2 locations (predicated on ASME/ANSI B31.8S section 7, figure 4) allow up to a maximum 10 percent safety margin over the MAOP. However, after allowing for pressure excursions above MAOP due to overpressure protection device settings, the actual safety margin is between 0 and 6 percent. PHMSA has determined that the continued reliance on those ASME/ANSI B31.8S section 7, figure 4-derived safety margins in more densely populated Class 2 locations does not ensure adequate identification and elimination of sub-critical defects before they grow to a size that would raise immediate safety concerns. Therefore, in this final rule, PHMSA chooses to retain the NPRM's predicted failure pressure threshold for metal loss anomalies in Class 2 locations of less than 1.39 times MAOP.

For Class 3 and Class 4 locations, PHMSA considered predicted failure pressure thresholds between 1.39 times and 1.50 times MAOP as requested by the committee. However, PHMSA has determined that, in order to provide adequate margin for public safety in higher- population-density Class 3 and 4 locations, PHMSA could not establish a predicted failure pressure threshold as low as 1.39 times MAOP. Therefore, in this final rule, PHMSA has provided a repair threshold for anomalies meeting a predicted failure pressure of less than 1.50 times MAOP for pipelines in Class 3 and Class 4 locations. PHMSA notes this approach would align repair criteria with the approach in § 192.619 for determining maximum allowable pressures for the same locations, and reflects that transmission pipelines in Class 3 and Class 4 locations are more robust (as a result of thicker walls and other design requirements) than those used in Class 1 and Class 2 locations.

PHMSA has provided similar repair criteria in this final rule for corrosion metal loss anomalies that are at a crossing of another pipeline; are in an area with widespread circumferential corrosion; could affect a girth weld; or that preferentially affects detected longitudinal seams that are formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0. Specifically, PHMSA is requiring the repair of conditions that reach less than 1.39 times the MAOP for anomalies in Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611. For those corrosion metal loss anomalies at all other Class 2 locations, as well as those anomalies in Class 3 and Class 4 locations, operators will have to repair them once they reach a predicted failure pressure of less than 1.50 times MAOP.

PHMSA is requiring the additional stringency in Class 1 locations and Class 2 locations compared to the general corrosion metal loss repair standard discussed above because, should corrosion at the crossing of other pipelines induce failure, multiple pipelines could be damaged or fail. Pipelines with anomalies located at areas of widespread circumferential corrosion could additionally lose pipe strength due to outside longitudinal (pulling force) loading on the pipeline. And, historically, longitudinal seams that are formed by direct-current welding, low-frequency or high-frequency electric resistance welding, electric flash welding, or that have a longitudinal joint factor of less than 1.0, are more likely to fail. Therefore, PHMSA has determined that more stringent repair criteria are necessary for corrosion metal loss anomalies that preferentially affect these longitudinal seams. In contrast, because pipelines in Class 3 and Class 4 locations are (as noted above) more robust than those in Class 1 and Class 2 locations, PHMSA has determined that it is unnecessary to impose different thresholds for pipelines in Class 3 and Class 4 locations based on whether they are located at the crossing of another pipeline.

As explained in the discussion for dent anomalies above, PHMSA agreed with commenters that the specific criteria for gouges and grooves was duplicative with other metal loss conditions and has chosen not to finalize gouge and groove criteria in this final rule. Therefore, the comments related to whether ILI tools can properly or reliably identify gouges and grooves specifically are moot.

F. Repair Criteria—§§ 192.714, 192.933

vi. General Discussion

Process for Analyzing Defects Discovered—§ 192.933

1. Summary of PHMSA's Proposal

Following the Enbridge hazardous liquid incident in 2010 that spilled nearly 1 million barrels of oil near Marshall, MI, in 2010, the NTSB recommended that PHMSA revise requirements in the hazardous liquid pipeline safety regulations at § 195.452(h)(2) related to the ''discovery of condition'' to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify PHMSA and provide an expected date when adequate information will become available.[46] The NTSB also recommended that PHMSA revise part 195 to state the acceptable methods for performing engineering assessments of ILI results, including the assessment of cracks coinciding with corrosion, with a safety factor that considers the uncertainties associated with sizing of crack defects (P–12–3). Although these recommendations were for the hazardous liquid pipeline safety regulations in part 195, the issues apply equally to gas pipelines regulated under part 192.

Accordingly, PHMSA proposed to amend paragraph (b) of § 192.933 to

[45] Those three scales pertain to (1) not exceeding 30 percent SMYS, (2) above 30 percent SMYS but not exceeding 50 percent SMYS, and (3) above 50 percent SMYS.

[46] NTSB Recommendation P–12–4, available at *https://www.ntsb.gov/safety/safety-recs/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-004.*

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require that operators notify PHMSA within 180 days following an assessment where the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline; and expand the requirements in § 192.933 to clarify that operators must assure that persons qualified by knowledge, training, and experience must analyze the data obtained from an ILI to determine if a condition could adversely affect the safe operation of the pipeline. PHMSA also proposed to require that operators explicitly consider uncertainties in reported results in identifying and characterizing anomalies, which includes uncertainties in tool tolerance, detection threshold, the probability of detection, the probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots.

PHMSA also proposed to amend paragraphs (a) and (d) of § 192.933 to require that operators document a pipeline's physical material properties and attributes that are used in remaining strength calculations in reliable, traceable, verifiable, and complete records. If such records were not available, operators would be required to base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607.

2. Summary of Public Comment

Commenters noted that there were potential issues with how the revised repair criteria and the proposed material verification requirements at § 192.607 would interact regarding remaining strength calculations. These commenters requested that, absent reliable data, PHMSA allow operators to use supportable, sound engineering judgments when calculating remaining strength. This would allow operators to establish the remaining strength of affected segments while material verification was completed. Similarly, commenters suggested if the value for specified minimum yield strength is unknown, operators should be able to use a conservative default value, such as 30,000 pounds per square inch (psi). For predicted failure pressure calculations, operators suggested they should be able to use the records they have on hand and operator knowledge for calculations until any necessary material properties are verified through § 192.607. Similarly, at the GPAC meeting on March 26, 2018, commenters representing the industry suggested PHMSA should allow, in the absence of traceable, verifiable, and complete material records,[47] for operators to use sound engineering judgment or otherwise conservative assumptions in repair-related decision making, and recommended PHMSA modify the regulations as such.

The EDF and PST supported PHMSA's proposals related to considering uncertainties in ILI results for identifying and characterizing anomalies. Several pipeline operators and industry trade associations on the other hand, including INGAA, expressed concern that the NPRM would require pipeline operators to repair anomalies that do not threaten pipeline integrity, stating that many anomalies that are identified by indirect measurements as requiring repair are later determined not to require repair upon examination in the field. These commenters requested that PHMSA change the proposed requirements to distinguish between ILI results and in-field examinations and start the repair timeline with the time an anomaly is examined in the field and not when it is identified by ILI.

INGAA suggested that PHMSA change the proposed requirements to differentiate between response, remediation, and repair, and that PHMSA replace ''repair'' with ''response'' in the terms ''2-year repair criteria'' and ''1-year repair criteria'' as those terms pertain to the non-HCA repair criteria. INGAA also requested that PHMSA further divide ''2-year response conditions'' into ''2-year response conditions and scheduled responses'' and similarly divide ''1-year response conditions'' into ''1-year response conditions and scheduled responses.'' INGAA suggested such a revision would be necessary because the proposed requirements for the response to, and repair of, potential pipeline anomalies do not recognize the differences between actions that operators take when evaluating the result of integrity assessments versus those actions operators take following in-field examinations of potential anomalies.

Several commenters requested that PHMSA change the proposed regulatory language to distinguish between ILI results and in-field examinations (response) and the actual remediation activity (repair) with a view to start the repair timeline after an anomaly is examined in the field and not when it is identified by ILI. Commenters suggested separate timelines to distinguish between the ''response'' and ''repair'' phases of pipeline remediation.

3. PHMSA Response

PHMSA addressed comments pertaining to the use of sound engineering judgment and assumed values to evaluate anomalies when data required for the evaluation is unknown or not available in traceable, verifiable, and complete records in the 2019 Gas Transmission Rule at § 192.712.[48] If an operator does not have one or more of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy v-notch toughness values, if applicable), the operator must use the conservative assumptions PHMSA provided and include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

In the Response to Petitions for Reconsideration on the 2019 Gas Transmission Rule,[49] PHMSA stated that if operators are missing any material properties during anomaly evaluations and repairs, operators must confirm those material properties under §§ 192.607 and 192.712(e) through (g). For consistency in this final rule, and to make this requirement more explicit, PHMSA has linked those material property confirmation requirements to the anomaly repair requirements by cross-referencing § 192.607 at both §§ 192.714 and 192.933. PHMSA will also note that, in accordance with the section 23 mandate in the 2011 Pipeline Safety Act, operators reported that approximately 13 percent of pipeline segment mileage in HCAs and Class 3 and Class 4 locations lack adequate documentation of the physical and operational characteristics of the pipelines necessary to confirm the proper MAOP. Such documentation is

[47] In an advisory bulletin dated May 7, 2012 (77 FR 26822), PHMSA provided guidelines for what records would meet a traceable, verifiable, and complete standard. The phrase ''traceable, verifiable, and complete'' matched a phrase from NTSB recommendation P–10–5, which recommended to the California Public Utilities Commission to ensure that PG&E ''aggressively and diligently searched documents and records relating to [. . .] natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas [. . .]. These records should be traceable, verifiable, and complete [. . .].'' See NTSB Recommendation P–10–5, available at *https://www.ntsb.gov/safety/safety-recs/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-10-005*. While PHMSA proposed that records meet a reliable, traceable, verifiable, and complete standard, PHMSA believes that being consistent with the guidance it provided in the May 2012 advisory bulletin and the NTSB recommendation will provide further clarity.

[48] See 84 FR 52236, 52251.

[49] 85 FR 40132 (July 6, 2020).

also critical for performing predicted failure pressure calculations.

In an earlier section of the repair criteria discussion, PHMSA noted that the identification of anomalies based on ILI results is an actionable indication that there might be an injurious defect in the pipeline. Establishing repair criteria based on operators discovering these actionable anomalies assures that these anomalies are investigated promptly and repaired. Therefore, PHMSA disagrees with commenters who suggested that there should be separate timelines for anomaly responses and repairs, as it would be prudent for operators to perform any necessary repairs once the operator has excavated the pipe and exposed the anomaly for investigation rather than deferring such repairs.

F. Repair Criteria—§§ 192.714, 192.933

vii. Miscellaneous Comments

1. Summary of Public Comments

Commenters were concerned that the requirements in this rulemaking would apply to gas gathering pipelines and requested that PHMSA clarify this is not the case. Similarly, the GPAC, in its late March 2018 meeting, recommended PHMSA clarify that the non-HCA repair criteria applied to those pipeline segments not currently covered under the IM regulations at subpart O.

Additionally, pipeline operators and their trade associations requested that PHMSA clarify the effective date of the repair provisions, as the requirements were proposed in an allegedly retroactive section of the regulations. These commenters claimed, as written, the proposed provisions would force operators to apply the revised repair criteria to prior ILI assessments that, at the time, met all the standards of the regulations. Some of these commenters recommended PHMSA establish reasonable, risk-based timeframes for operators to implement repairs of anomalies that were historically identified and were repaired in accordance with the code requirements of the time. The GPAC, during their meeting in late March of 2018, similarly recommended that PHMSA add an effective date to these general repair provisions to clarify that they were not retroactive.

Some commenters also discussed the application of the proposed repair criteria to pipelines outside of HCAs that have established their MAOP under the alternative requirements at § 192.620. The GPAC recommended PHMSA apply appropriate predicted failure pressure factors to alternative MAOP pipelines based on class location and design factors for scheduled conditions under the repair criteria.

2. PHMSA Response

PHMSA did not intend for the new repair criteria for non-HCA pipe segments to be applicable to gas gathering pipelines, HCA segments, or offshore transmission lines. However, PHMSA will consider expanding the application of these provisions in the future. In this final rule, to clarify that the new non-HCA repair criteria apply only to onshore transmission lines, PHMSA placed the new non-HCA repair criteria in a new § 192.714, which applies only to onshore transmission lines. Subsequently, PHMSA withdrew all proposed changes to § 192.713. PHMSA has also revised § 192.9 in this final rule to exempt regulated gas gathering lines from the requirements of § 192.714. Additionally, PHMSA has modified § 192.711 in this final rule to clarify that the new repair criteria in § 192.714 do not apply to gathering lines or HCA segments subject to subpart O. The current and unchanged § 192.713 would continue to apply to regulated gas gathering lines. Although the creation of a new § 192.714 was not discussed at the GPAC, PHMSA determined that this approach was a clearer means to specify that the new non-HCA repair criteria only apply to onshore transmission pipelines and meet the intent of the GPAC recommendation to clarify that the non-HCA repair criteria do not apply to gathering lines, HCA segments, or offshore transmission lines. Furthermore, PHMSA determined that this approach avoids duplication of repair language in other code sections.

PHMSA did not intend to imply that the new repair criteria were to be applied retroactively and has clarified this intent in this final rule by revising § 192.711(b) to include an effective date as recommended by the GPAC.

Regarding alternative MAOP pipelines, the NPRM did not propose, and therefore did not give opportunity for comment on, changes to repair criteria for alternative MAOP pipe segments. However, PHMSA agrees with commenters that the language proposed in the NPRM could create ambiguity with respect to the applicability of the non-HCA repair criteria to pipe with MAOP established in accordance with § 192.620. Therefore, in this final rule, PHMSA more broadly exempted alternative MAOP lines from compliance with non-HCA repair criteria and reiterated the applicability of the repair criteria provided at the alternative MAOP provisions under § 192.620(d)(11) as they provide a comparable level of safety based upon the operating factors. PHMSA did not make a corresponding change to § 192.933, as alternative MAOP pipelines in HCAs must meet both the HCA and the alternative MAOP repair criteria. This approach is preferable to repeating the alternate MAOP repair criteria in two locations of part 192.

G. Definitions—§ 192.3

i. Close Interval Survey

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed a new definition for ''close interval survey'' as a series of closely spaced pipe-to-electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline and may cause corrosion, and for the purpose of quantifying voltage drops other than those across the structure electrolyte boundary.

2. Summary of Public Comment

Comments from the trade associations and GPAC members representing the industry questioned whether PHMSA should tie the definition of ''close interval survey'' to a corresponding NACE standard for consistency. PHMSA presented some minor changes to the definition at the meeting on March 28, 2018, and the committee voted 13–0 that PHMSA should adopt those changes into the final rule.

3. PHMSA Response

After considering the comments and GPAC recommendations, PHMSA is adopting the definition of ''close interval survey'' as recommended by GPAC. As such, PHMSA has specified that the pipe-to-electrolyte potential measurements are taken ''over the pipe,'' and added the phrase ''such as when performed as a current interrupted, depolarized, or native survey'' to qualify what is ''other than those across the structure electrolyte boundary.''

G. Definitions—§ 192.3

ii. Distribution Center

1. Summary of PHMSA's Proposal

PHMSA proposed to define a ''distribution center'' as a location where gas volumes are either metered or have a pressure or volume reduction prior to delivery to customers through a distribution line.

2. Summary of Public Comment

AGL Resources, Pipeline Safety Coalition, Southern California Gas

Company, Spire STL Pipeline LLC, and Xcel Energy supported PHMSA's intention to define the term ''distribution center.'' In particular, AGL Resources stated that the proposed definition would remove confusion and the potential for conflict between operators and regulators throughout the Nation. Like its comments on the proposed definition for ''transmission line,'' Xcel Energy suggested that PHMSA add an implementation period for operators to handle the regulatory impacts of the new definition.

AGA supported PHMSA's effort to define a ''distribution center'' to ensure consistency and certainty in the identification of transmission lines. However, AGA also stated that PHMSA failed to provide any justification or explanation for its proposed definition, and AGA proposed an alternative definition of ''distribution center'' where piping downstream of a distribution center that operates above 20 percent SMYS would be classified as a transmission line. Other organizations, such as Alliant Energy, Dominion Energy, PECO Energy, Paiute Pipeline Company, and Southwest Gas Corporation, supported AGA's alternative definition.

TPA recommended PHMSA revise the proposed definition of ''distribution center'' to provide a clear endpoint for transmission lines and the start of distribution lines. Atmos Energy stated that the proposed definition did not recognize the many possible configurations of pipes in which transmission pipelines deliver to distribution systems. For example, Oleksa and Associates stated that some distribution systems may have no meters prior to delivery to customers and also may have no pressure or volume reductions (*e.g.,* a distribution system supplied by a landfill). Lastly, Cascade Natural Gas requested the term ''distribution center'' clearly refer to distribution pipelines and that such a definition should not be included in a rulemaking for transmission and gathering pipelines.

At the GPAC meeting, PHMSA offered for the committee's consideration the option of recommending withdrawal of the proposed definition for ''distribution center.'' Committee members opposed this suggestion, stating that finalizing a definition for ''distribution center'' would provide the industry and regulators with regulatory certainty and clarity. During the meeting, committee members came to a consensus on the definition of a ''distribution center'' based on comments the industry provided. However, certain committee members representing the public were not inclined to adopt a definition of a ''distribution center'' that was based on the comments provided by industry and wished to defer to PHMSA regarding the wordsmithing of the definition.

Following the discussion, the committee voted 10–0 that the definition for ''distribution center'' was technically feasible, reasonable, cost-effective, and practicable if PHMSA incorporated a definition for ''distribution center'' in the final rule and considered revising the definition to mean the initial point where gas enters piping used to deliver gas to customers for end use as opposed to customers who purchase it for resale. Examples of a distribution center would include a metering location; a pressure reduction location; or where there is a reduction in the volume of gas, such as a lateral off a transmission pipeline.

3. PHMSA Response

After considering the comments received and the GPAC's recommendations, PHMSA is adopting the definition recommended by GPAC so that a ''distribution center'' means the initial point where gas enters piping used to deliver gas to customers for end use as opposed to customers who purchase it for resale.

PHMSA disagrees that an implementation period for the definition is appropriate, given that this term has been in use for a long period of time. PHMSA agrees with commenters for the need to clarify the end point of transmission and the start of distribution. PHMSA agrees with those commenters who suggested that piping downstream of a distribution center operating at above 20 percent SMYS should be considered a transmission line and is modifying the definition of ''transmission line'' accordingly in this final rule.

G. Definitions—§ 192.3

iii. Dry Gas or Dry Natural Gas

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed a new definition for the term ''dry gas or dry natural gas'' to mean gas with less than 7 pounds of water per million cubic feet that is not subject to excessive upsets allowing electrolytes into the gas system.

2. Summary of Public Comment

GPAC members representing the industry asked whether PHMSA should tie the definition for dry gas to the corresponding NACE standard for continuity. Committee members representing the public were concerned about incorporating by reference the definition into the regulations but were amenable to lifting the language directly from the standard to ensure consistency. PHMSA representatives noted that the agency could consider the NACE definition and make the definition for dry gas less prescriptive than proposed.

After discussion, the committee voted 13–0 that the definition for ''dry gas or dry natural gas'' was technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the definition to be consistent with the NACE definition as discussed at the meeting.

3. PHMSA Response

PHMSA has taken into consideration the comments as well as the GPAC recommendations and is modifying the definition for ''dry gas or dry natural gas'' to be consistent with the NACE standard. More specifically, the definition specifies that ''dry gas or dry natural gas'' is gas ''above its dew point and without condensed liquids.''

G. Definitions—§ 192.3

iv. Electrical Survey

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed revising the term ''electrical survey'' so that it means a series of closely spaced measurements of the potential difference between two reference electrodes to determine where the current is leaving the pipe on ineffectively coated or bare pipelines.

2. Summary of Public Comment

PHMSA received a variety of comments on the definition for ''electrical survey.'' Some commenters expressed support for the definition and its inclusion in the regulations. Other commenters supported the concept of the definition but provided PHMSA with varying edits to improve on the clarity and functionality of the definition.

Several commenters noted that the proposed definition for electrical survey was duplicative with the proposed definition for ''close interval survey'' and recommended that PHMSA retain the definition for close interval survey instead. Some of these commenters noted that the proposed definition for electrical survey was more restrictive than the definition of electrical survey in NACE standards and excluded certain types of surveys. Other commenters suggested that the proposed definition for electrical survey should match the definition in various NACE standards.

NACE itself believed that the definition used in the NPRM for

''electrical survey'' was ambiguous and inaccurate, stating the proposed definition does not align with current terminology and accepted pipeline integrity practices. NACE recommended that PHMSA use the definition for ''indirect inspection'' in NACE SP0502, which is widely accepted as standard practice and should meet PHMSA's intent.

The GPAC recommended that PHMSA withdraw the proposed changes to appendix D as a part of the recommended revisions to the proposed corrosion control regulations. There was no further discussion on the definition for the term, and the committee voted, 13–0, to delete the definition from the rule.

3. PHMSA Response

PHMSA notes that, when the committee voted to withdraw the proposed changes to appendix D as a part of the corrosion control discussion, a revised definition for electrical survey was unnecessary as all references to ''electrical surveys'' were removed. Therefore, PHMSA agrees with the GPAC recommendation and has struck the proposed revision to the definition of ''electrical survey'' from this final rule.

G. Definitions—§ 192.3

v. Hard Spot

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to define a ''hard spot'' as steel pipe material with a minimum dimension greater than 2 inches (50.8 mm) in any direction with hardness greater than or equal to Rockwell 35 HRC, Brinnel 327 HB, or Vickers 345 HV_{10}.

2. Summary of Public Comment

During the GPAC meeting, committee members noted there was a small editorial correction that needed to be made—changing ''Brinnel'' to ''Brinell''—and also recommended that the definition be prefaced with the phrase ''an area on'' so that the definition reads ''an area on steel pipe material [. . .].''

3. PHMSA Response

PHMSA has modified the proposed definition of hard spot as the GPAC recommended for this final rule.

G. Definitions—§ 192.3

vi. In-Line Inspection (ILI) and In-Line Inspection Tool or Instrumented Internal Inspection Device

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add definitions for ''in-line inspection (ILI)'' and ''in-line inspection tool or instrumental internal inspection device'' to § 192.3. Specifically, the term ''in-line inspection'' would mean the inspection of a pipeline from the interior of the pipe using an ILI tool, which may also be known as intelligent or smart pigging. The term ''in-line inspection tool or instrumented internal inspection device'' would mean a device or vehicle that inspects a pipeline from the inside using a non-destructive technique. Such a device might also be called an intelligent or smart pig.

2. Summary of Public Comment

NACE International commented that the proposed definitions of ''in-line inspection'' and ''in-line inspection tool or instrumented internal inspection device'' do not align with the definition provided in NACE International Standard SP01024 or SP0102, respectively. NACE International suggested that PHMSA use the definition in NACE Standard SP0102, as PHMSA had proposed to incorporate by reference the standard in the regulations.

The GPAC reviewed the proposed definitions and, following their discussion, voted 13–0 that the definitions for ''in-line inspection'' and ''in-line inspection tool or instrumented internal inspection device'' were technically feasible, reasonable, cost-effective, and practicable if PHMSA considered clarifying in the preamble that the phrase ''a line that can accommodate inspection by means of an instrumented in-line inspection tool'' referred to pipeline segments that can be inspected with free-swimming ILI tools without any permanent physical modification of the pipeline segment.

3. PHMSA Response

After considering these comments, PHMSA is modifying the definitions of both ''in-line inspection'' and ''in-line inspection tool or instrumented internal inspection device'' based on the definitions in NACE SP0102–2010. In accordance with the GPAC recommendation, PHMSA is also noting that an ILI can include both tethered and self-propelled (*i.e.,* ''free-swimming'') tools.

G. Definitions—§ 192.3

vii. Transmission Line

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to modify the second criterion of the ''transmission line'' definition to base the percentage of SMYS on the MAOP of the pipeline, whereas currently it is based on the pressure at which the pipeline is operating. PHMSA also proposed editorial changes to the ''Note'' section of the definition and make it clearer that ''factories, power plants, and institutional users of gas'' were examples of a large-volume customer.

2. Summary of Public Comment

AGA asserted that modifying the second criterion in the ''transmission line'' definition in conjunction with other definition changes PHMSA proposed would result in the reclassification of some transmission pipelines to distribution lines and some distribution pipelines to transmission lines. Several pipeline operators and industry representatives, including AGL Resources, Alliant Energy, Black Hills Energy, Cascade Natural Gas, Centerpoint Energy, Spire, Delmarva Power, National Grid, National Fuel Gas Supply Corporation, North Dakota Petroleum Council, Paiute Pipelines, TECO Peoples Gas, TPA, and PECO Energy, supported AGA's comments or provided similar recommendations. Additionally, Dominion East Ohio and Southwest Gas objected to PHMSA's proposed modifications to the definition, stating that the proposed definition would burden operators with ongoing IM programs with no additional benefit to public safety.

APGA commented that PHMSA's slight rewording of the note in the transmission definition regarding types of large-volume customers could be interpreted to mean that only factories, power plants, and institutional users of gas can be large-volume customers. APGA suggested PHMSA change the proposed language in the final rule to clarify that those listed items are examples of large-volume customers rather than a comprehensive list.

ONE Gas proposed an alternative simplified approach to the definition of ''transmission line'' that focuses on a line's MAOP as it relates to the percentage of yield strength.

There were various comments from other pipeline operators, including the suggestion that PHMSA remove the term ''distribution center'' from the definition of ''transmission line,'' allow operators to use MAOP to determine a transmission pipeline, and provide an implementation period for operators to incorporate regulatory requirements of the newly defined transmission lines.

During the GPAC meeting, committee members representing the industry expressed support for allowing operators to designate pipelines voluntarily as transmission lines, especially if their risk profile was high,

so that operators could operate and maintain those lines to a higher standard.

Following the discussion, the committee voted 10–0 that the definition for ''transmission line'' was technically feasible, reasonable, cost-effective, and practicable if PHMSA included the phrase ''an interconnected series of pipelines'' within the text of the definition and allowed operators to designate pipelines voluntarily as transmission lines.

3. PHMSA Response

PHMSA has considered the comments received regarding the proposed definition of a ''transmission line.'' PHMSA agrees with the recommendation from the GPAC to allow operators to designate pipelines voluntarily as transmission lines, as well as the recommendation from the GPAC to include the phrase ''an interconnected series of pipelines.'' Accordingly, PHMSA has revised the definition of ''transmission line'' in this final rule to include these recommendations.

PHMSA agrees with commenters that the language to clarify the examples of large-volume customers may imply a specific list and has withdrawn the changes to the note in the definition. In response to the comment on providing an implementation period for compliance with the new definition, PHMSA notes that it does not apply separate implementation periods to definitions outside of the effective date of the rule. If PHMSA determines that corresponding regulations would be affected by a change in a definition, it incorporates appropriate implementation time to those regulations as necessary.

PHMSA also notes that, per the comments received on the definition for ''distribution center,'' it agreed with commenters who suggested that piping downstream of a distribution center operating at above 20 percent of SMYS should be considered a transmission line and is modifying the definition of ''transmission line'' accordingly in this final rule.

PHMSA sees no functional difference in changing the definition of a transmission line from a pipeline that operators at a hoop stress of 20 percent or more of SMYS and a pipeline that has a MAOP of 20 percent or more of SMYS. For a pipeline to operate above 20 percent or more of SMYS, it will have an MAOP of 20 percent or more of SMYS. If an operator has a pipeline where the theoretical MAOP is higher than the pipeline's actual operating pressure, and therefore the line would need to be reclassified, the operator could reduce the MAOP of the line to keep the line's classification the same without affecting its operating pressure.

G. Definitions—§ 192.3

viii. Wrinkle Bend

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to define ''wrinkle bend'' as a bend in the pipe that was formed in the field during construction such that the inside radius of the bend has one or more ripples of various sizes or where the ratio of peaks to peaks or peaks to valleys are of a certain size, or where a mathematical equation could be substituted when a wrinkle bend's length cannot reliably be determined.

2. Summary of Public Comment

There was no significant public comment on this definition, and the GPAC recommended PHMSA adopt the definition as it was published in the NPRM.

3. PHMSA Response

PHMSA adopts the definition as it was published in the NPRM.

IV. Section-by-Section Analysis

Section 192.3 Definitions

Section 192.3 provides definitions for various terms used throughout part 192. In support of other regulations adopted in this final rule, PHMSA is amending the definition of ''transmission line'' and is adding new definitions for ''close interval survey,'' ''distribution center,'' ''dry gas or dry natural gas,'' ''hard spot,'' ''in-line inspection,'' ''in-line inspection tool or instrumented internal inspection device,'' and ''wrinkle bend.'' The definitions, including ''in-line inspection,'' ''dry gas or dry natural gas,'' and ''hard spot,'' clarify technical terms used in part 192 or in this rulemaking.

Section 192.7 What documents are incorporated by reference partly or wholly in this part?

Section 192.7 lists documents that are incorporated by reference in part 192. PHMSA is making conforming amendments to § 192.7 to include two NACE standard practice documents regarding SCCDA and ICDA.

Section 192.9 What requirements apply to gathering lines?

Section 192.9 lists the requirements that are applicable or not applicable to gathering lines. This final rule addresses several new requirements for transmission lines that are not intended to apply to gathering lines; PHMSA is adopting in this final rule revisions to § 192.9 to except each of offshore and Types A, B, and C[50] gas gathering lines from those requirements.

Section 192.13 What general requirements apply to pipelines regulated under this part?

Section 192.13 prescribes general requirements for gas pipelines. PHMSA has determined that public safety and environmental protection would be improved by requiring operators of transmission lines to evaluate and mitigate risks during all phases of the useful life of a pipeline as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including the MOC process.

As such, PHMSA has added a new paragraph (d) to § 192.13 with a general clause for transmission pipeline operators that invokes the requirements for the MOC process as it is outlined in ASME/ANSI B31.8S, section 11, and explicitly articulates the requirements for a MOC process applicable to onshore gas transmission pipelines. This final rule requires each operator to have a MOC process that must include the reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. While these general attributes of change management are already required for covered segments by virtue of the incorporation by reference of ASME/ANSI B31.8S, PHMSA believes it will improve the visibility and emphasis on these important program elements to require them for all onshore transmission pipelines directly in the rule text.

Section 192.18 How To Notify PHMSA

Section 192.18 in subpart A contains the procedure for an operator to submit notifications to PHMSA. Paragraph (c) has been modified to incorporate notification requirements for the use of ''other technology'' with external corrosion control and ICDA per §§ 192.461(g) and 192.927(b).[51] This is

[50] PHMSA notes that it has introduced in this final rule revisions to § 192.9(e), which paragraph was adopted in the Gas Gathering Final Rule, to identify specific provisions of part 192 that would apply to the new Type C category of part 192-regulated onshore gas gathering pipelines.

[51] PHMSA notes that between publication of this final rule and its effective date, regulatory amendments to § 191.18 adopted in rulemaking published in April 2022 will have been codified in the Code of Federal Regulations. ''Pipeline Safety:

Continued

consistent with the requirements PHMSA issued with the use of other technology for provisions finalized in the 2019 Gas Transmission Rule.

Section 192.319 Installation of Pipe in a Ditch

Section 192.319 prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. Sometimes pipe coating is damaged during the construction process while it is being handled, lowered, and backfilled, which can compromise its ability to protect against external corrosion. Accordingly, this final rule adds new paragraphs (d) through (g) to § 192.319, which require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfilling is completed and remediate coating damage. Mechanical damage is also detectable by these indirect assessment methods, since the forces that can mechanically damage steel pipe usually result in detectable coating defects.

If an operator uses ''other technology'' to perform an assessment required under this section, paragraph (e) requires the operator to notify PHMSA in accordance with § 192.18. Paragraph (g) requires each operator of transmission pipelines to make and retain, for the life of the pipeline, records documenting the coating assessment findings and repairs. The additional requirements of this section do not apply to gas gathering pipelines or distribution mains.

Section 192.461 External Corrosion Control: Protective Coating

Section 192.461 prescribes requirements for protective coating systems. Certain types of coating systems that have been used extensively in the pipeline industry can impede the process of cathodic protection if the coating disbonds from the pipe. Accordingly, this final rule amends paragraph (a)(4) to require that pipe coating has sufficient strength to resist damage during installation and backfill, and it also adds a new paragraph (f) to require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfill is completed or anytime there is an indication that the coating might be compromised. To ensure the prompt remediation of any severe coating damage, new paragraph (h) requires operators create a remedial action plan and provides the specific timing requirements for repairs. New paragraph (g) requires an operator to notify PHMSA, in accordance with § 192.18, if using ''other technology'' for the coating assessment, and paragraph (i) specifies the documentation requirements for this section. The additional requirements of this section do not apply to gas gathering pipelines or distribution mains.

Section 192.465 External Corrosion Control: Monitoring

Section 192.465 requires that operators monitor CP and take prompt remedial action to correct deficiencies indicated by the monitoring. To clarify that regulatory requirement, this final rule amends paragraph (d) to require that operators of onshore transmission pipelines must complete remedial action no later than the next monitoring interval specified in § 192.465, within 1 year, or within 6 months of obtaining any permits, whichever is less.

This final rule also adds a new paragraph (f) to require onshore gas transmission operators to conduct annual test station readings to determine if CP is below the level of protection required in subpart I. For non-systemic or location-specific causes of insufficient CP, the operator must investigate and mitigate the cause. For insufficient CP due to systemic causes, an operator must complete CIS with the protective current interrupted, unless it is impractical to do so based on a geographical, technical, or safety reason. For example, issues related to cost would not be an adequate reason for not performing the survey, whereas performing a survey on a pipeline protected by direct buried sacrificial anodes (anodes directly connected to the pipelines) might be impractical. The revisions to paragraph (d) and new paragraph (f) do not apply to gas gathering lines or distribution mains.

Section 192.473 External Corrosion Control: Interference Currents

Interference currents can negate the effectiveness of CP systems. Section 192.473 currently prescribes general requirements to minimize the detrimental effects of interference currents. However, subpart I does not presently contain specific requirements to monitor and mitigate detrimental interference currents. Accordingly, this final rule adds a new paragraph (c) to require that onshore gas transmission operator corrosion control programs include interference surveys to detect the presence of interference currents when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced. Sources of stray current can include co-located pipelines, structures, HVAC power lines, new or enlarged power substations, new pipelines, and other structures. They can also include additional generation, a voltage uprating, and additional lines. The rule also requires operators perform remedial actions no later than 15 months after completing the interference survey, with an allowance for permitting, to protect the pipeline segment from detrimental interference currents. These additional requirements do not apply to gas gathering pipelines or distribution mains.

Section 192.478 Internal Corrosion Control: Monitoring

Section 192.477 prescribes requirements to monitor internal corrosion if corrosive gas is being transported. However, the existing rules do not prescribe operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system modifications, gas supply changes, upset conditions, or other changes. This could result in operators not identifying internal corrosion if an initial assessment did not identify the presence of corrosive gas. Accordingly, PHMSA has determined that additional requirements are needed to ensure that operators effectively monitor their gas stream quality to identify if, and when, corrosive gas is being transported and mitigate deleterious gas stream constituents (*e.g.,* contaminants or liquids).

Therefore, this final rule adds a new § 192.478 to require onshore gas transmission operators monitor for known deleterious gas stream constituents and evaluate gas monitoring data once every calendar year, not to exceed a period of 15 months. Additionally, this final rule adds a requirement for onshore gas transmission operators to review their internal corrosion monitoring and mitigation program annually, not to exceed 15 months, and adjust the program as necessary to mitigate the presence of deleterious gas stream constituents. These requirements are in addition to the existing requirements to check coupons or perform other methods to monitor for the actual

Requirement of Valve Installation and Minimum Rupture Detection Standards,'' 87 FR 20940 (Apr. 8, 2022) (identifying an effective date in October 2022) (Valve Installation Final Rule). The amendatory text at the end of this final rule, therefore, reflects the text of § 192.18 as it will be revised when the Valve Installation Final Rule becomes effective.

presence of internal corrosion in the case of transporting a known corrosive gas stream. The new § 192.478 does not apply to gas gathering pipelines or distribution mains.

Section 192.485 Remedial Measures: Transmission Lines

Section 192.485 prescribes requirements for operators to perform remedial measures to address general corrosion and localized corrosion pitting in transmission pipelines. For such conditions, the requirements specify that an operator may determine the strength of pipe based on actual remaining wall thickness by using the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3–805 (RSTRENG). PHMSA has determined that additional requirements are needed beyond ASME/ANSI B31G and RSTRENG to ensure such calculations have a sound basis and has revised § 192.485(c) to specify that an operator must calculate the remaining strength of the pipe in accordance with § 192.712, which prescribes important aspects such as pipe and material properties, assumptions allowed when data is unknown, accounting for uncertainties, and recordkeeping requirements.

Section 192.613 Continuing Surveillance

Extreme weather and natural disasters can affect the safe operation of a pipeline. Accordingly, this final rule revises § 192.613 to require operators to perform inspections after these events and take appropriate remedial actions.

Section 192.710 Transmission Lines: Assessments Outside of High Consequence Areas

Section 192.710 prescribes requirements for the periodic assessment of certain pipelines outside of HCAs. In the NPRM, PHMSA proposed for operators to use the non-HCA repair criteria being finalized in this rule if they performed an assessment on a non-HCA pipeline and discovered an anomaly requiring repair. However, in splitting the rulemaking, PHMSA finalized the assessment requirement in the 2019 Gas Transmission Final Rule but did not incorporate regulatory text establishing the corresponding repair criteria. Therefore, in this final rule, PHMSA has revised the assessment requirement at § 192.710 to require operators to use the repair criteria finalized in this rulemaking if anomalies are discovered during these assessments.

Section 192.711 Transmission Lines: General Requirements for Repair Procedures

Section 192.711 prescribes general requirements for repair procedures. For non-HCA segments, the existing regulations required that operators make permanent repairs as soon as feasible. However, no specific repair criteria were detailed, and no specific timeframe or pressure reduction requirements were provided. PHMSA has determined that more specific repair criteria are needed for pipelines not covered under the integrity management regulations. Such repair criteria will help to maintain safety in a consistent manner in Class 1 through Class 4 locations that may have significant populations but that are not HCAs. Accordingly, this final rule amends paragraph (b)(1) of § 192.711 to require operators remediate specific conditions, as defined in § 192.714, on non-HCA gas transmission pipelines. Paragraph (b)(1) retains the existing requirement that operators must repair anomalies on gathering pipelines regulated in accordance with § 192.9 as soon as feasible.

Section 192.712 Analysis of Predicted Failure Pressure and Critical Strain Levels

In the 2019 Gas Transmission Rule, PHMSA updated and codified minimum standards for determining the predicted failure pressure of pipelines containing anomalies or defects associated with corrosion metal loss and cracks. In this final rule, PHMSA is revising the repair criteria for gas transmission pipelines, including for dents. Some of the revised dent repair criteria allow operators to determine critical strain levels for dents and defer repairs if critical strain levels are not exceeded. As such, PHMSA has established minimum standards for operators to calculate critical strain levels in pipe with dent anomalies or defects and has included those standards in a new paragraph (c) of § 192.712. The title of this section has also been updated to reflect this addition. PHMSA has also provided reassessment schedules for engineering critical assessments that operators perform to determine maximum reevaluation intervals to ensure that anomalies do not grow to critical sizes.

Section 192.714 Transmission Lines: Permanent Field Repair of Imperfections and Damages

Section 192.713 prescribes requirements for the permanent repair of pipeline imperfections or damage that impairs the serviceability of steel transmission pipelines operating at or above 40 percent of SMYS. PHMSA has determined that more explicit requirements are needed in § 192.714 to identify criteria for the severity of imperfections or damage that must be repaired, and to identify the timeframe within which repairs must be made for pipelines in all class locations that are not in HCAs. Pipelines not in HCAs can still have significant populations that could be harmed by a pipeline leak or rupture. As such, PHMSA has determined that repair criteria should apply to any onshore transmission pipeline not covered under the IM regulations in subpart O. PHMSA believes that establishing these non-HCA segment repair conditions for Class 1 locations through Class 4 locations are important because, even though they are not within HCAs, these locations could be in highly populated areas and are not without consequence to public safety and the environment.

Accordingly, this final rule creates a new § 192.714 to establish repair criteria for immediate, 2-year, and monitored conditions that the operator must remediate or monitor to ensure pipeline safety. PHMSA is using the same criteria as it is issuing for HCAs, except conditions for which a 1-year response is required in HCAs will require a 2-year response in non-HCA pipeline segments so that operators can allocate their resources to HCAs on a higher-priority basis. Additionally, PHMSA is prescribing more explicit requirements for the *in situ* evaluation of cracks and crack-like defects using in-the-ditch tools whenever required, such as when an ILI, SCCDA, pressure test failure, or other assessment identifies anomalies that suggest the presence of such defects.

Section 192.911 What are the elements of an integrity management program?

Paragraph (k) of § 192.911 requires that IM programs include a MOC process as outlined in ASME/ANSI B31.8S, section 11. PHMSA has determined that specific attributes and features of the MOC process that are currently specified in ASME/ANSI B31.8S, section 11, should be codified directly within the text of subpart O for HCAs to make the requirements readily available to all operators of onshore gas transmission pipelines. This change is consistent with the new paragraph (d) in § 192.13 for all onshore transmission pipelines.

Section 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

Section 192.917 requires that operators with IM programs for covered pipeline segments identify potential threats to pipeline integrity and use the threat identification in their integrity program. This performance-based process includes requirements to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment. The regulations include special requirements for operators to address plastic pipe and particular threats, such as third-party damage and manufacturing and construction defects.

As specified in § 192.907(a), PHMSA expected operators to start with a framework for IM, which would later evolve into a more detailed and comprehensive program, and expected that an operator would continually improve its IM program as it learned more about the process and about the material condition of its pipelines through integrity assessments. PHMSA elaborated on this philosophy in the 2003 IM rule.[52]

Even though the IM regulations have been in effect since 2004, PHMSA still finds certain operators have poorly developed IM programs. The clarifications and additional specificity adopted in this final rule, with respect to the processes an operator must use in implementing the threat identification, risk assessment, and preventive and mitigative measure program elements, reflect PHMSA's expectation regarding the degree of progress operators should be making, or should have made, during the first 10 years of the implementation of the IM regulations.

The current IM regulations incorporate by reference ASME/ANSI B31.8S to require that operators implement specific attributes and features of the threat identification, data analysis, and risk assessment process in their IM programs. In this final rule, PHMSA is amending § 192.917 to insert certain critical features of ASME/ANSI B31.8S directly into the regulatory text. PHMSA is specifying several pipeline attributes that must be included in pipeline risk assessments and is explicitly requiring that operators integrate analyzed information and ensure that data is verified and validated to the maximum extent practical. To the degree that subjective data from SMEs must be used, PHMSA is requiring that an operator's program account and compensate for uncertainties in the risk model used and the data used in the operator's risk assessment. PHMSA is also in this final rule revising the non-exhaustive list of data to be collected for clarity or to eliminate redundant language.

PHMSA will note that in its advisory bulletin on the verification of records that ''verifiable'' records are those in which information is confirmed by other complementary, but separate, documentation. Such records might include contract specifications for a pressure test of a line segment complemented by field logs or purchase orders with pipe specifications verified by metallurgical tests of coupons pulled from the same pipe segment.

Additionally, PHMSA is clarifying the performance-based risk assessment aspects of the IM regulations in this final rule by specifying that operators must perform risk assessments that are adequate for evaluating the effects of interacting threats; determine additional P&M measures needed; analyze how a potential failure could affect HCAs, including the consequences of the entire worst-case incident scenario from initial failure to incident termination; identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location; account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and evaluate risk reduction associated with candidate risk reduction activities, such as P&M measures.

In consideration of NTSB recommendation P–11–18, PHMSA is adopting regulations that require operators to validate their risk models considering incident, leak, and failure history and other historical information. These features are currently requirements because they are incorporated by reference in ASME/ANSI B31.8S. However, PHMSA has found that provisions incorporated directly into its regulatory text have higher levels of compliance. The final rule also amends the requirements for plastic pipe to provide specific examples of integrity threats for plastic pipe that must be addressed.

Section 192.923 How is direct assessment used and for what threats?

This final rule incorporates by reference NACE SP0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas,'' for addressing ICDA, and NACE SP0204–2008, ''Stress Corrosion Cracking Direct Assessment,'' for addressing SCCDA. Accordingly, PHMSA has revised § 192.923(b)(2) and (3) to require operators comply with these standards.

Section 192.927 What are the requirements for using internal Corrosion Direct Assessment (ICDA)?

Section 192.927 specifies requirements for gas transmission pipeline operators who use ICDA for IM assessments. The requirements in § 192.927 were promulgated before NACE SP0206–2006 was published and require that operators follow ASME/ANSI B31.8S provisions related to ICDA. PHMSA has reviewed NACE SP0206–2006 and finds that it is more comprehensive and rigorous than either § 192.927 or ASME/ANSI B31.8S in many respects. Therefore, PHMSA is incorporating NACE SP0206–2006 into the regulations for the performance of ICDA and is establishing additional requirements for addressing covered segments within the technical process defined by the NACE standard.

This final rule requires that operators perform two direct examinations within each covered segment the first time ICDA is performed. These examinations are in addition to those required to comply with the NACE standard. The additional examinations are consistent with the current requirement in § 192.927(c)(5)(ii) that operators apply more restrictive criteria when conducting ICDA for the first time and are intending to verify, within the HCA, that the results of applying the process of NACE SP0206–2006 for the ICDA are acceptable. Applying the process for NACE SP0206–2006 requires more precise knowledge of the pipeline orientation (particularly slope) than operators may have in many cases. Conducting examinations within the HCA during the first application of ICDA will verify that applying the ICDA process provides an operator with adequate information about the covered segment. Operators who identify internal corrosion on these additional examinations, even though excavations at locations determined using NACE SP0206–2006 did not identify any internal corrosion, will know that improvements are needed to their knowledge of pipeline orientation. In addition, operators will know they need other adjustments to their application of the NACE standard to the covered segment for using ICDA in the future. Section 192.927(b) and (c) are revised in this final rule to address these issues.

PHMSA notes that, for these requirements, operators are prohibited from using assumed pipeline or operational data. Any data an operator

[52] ''Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)''; 68 FR 69778 (Dec. 15, 2003). See 68 FR 69789.

uses for its ICDA process should be based on known information, such as the pipeline route, the pipeline diameter, and pipeline flow inputs and outputs. Operators can choose to base their ICDA process on data that is more conservative than their known pipeline or operational data.

Section 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

Section 192.929 specifies requirements for gas transmission pipeline operators who use SCCDA for IM assessments. The requirements in § 192.929 were promulgated before NACE Standard Practice SP0204–2008 was published, and the standard requires that operators follow Appendix A3 of ASME/ANSI B31.8S. That appendix provides some guidance for conducting SCCDA but is limited to SCC that occurs in high-pH environments. Experience has shown that pipelines can also experience SCC degradation in areas where the surrounding soil has a pH near neutral (referred to as near-neutral SCC). NACE SP0204–2008 addresses near-neutral SCC as well as high-pH SCC. NACE SP0204–2008 also provides technical guidelines and process requirements that are both more comprehensive and rigorous for conducting SCCDA than § 192.929 or ASME/ANSI B31.8S.

Since NACE SP0204–2008 provides comprehensive guidelines on conducting SCCDA and is more comprehensive in scope than Appendix A3 of ASME/ANSI B31.8S, PHMSA has concluded the quality and consistency of SCCDA conducted under IM requirements would be improved by requiring operators to use NACE SP0204–2008. The final rule accomplishes this.

Section 192.933 What actions must be taken to address integrity issues?

Section 192.933 specifies injurious anomalies and defects that operators must remediate and the timeframes within which such remediation must occur. PHMSA determined that the existing regulations for repair criteria had gaps, as some injurious anomalies and defects were not listed as requiring remediation in a timely manner commensurate with their seriousness. To remedy this, in this final rule, PHMSA is designating the following types of defects as immediate conditions: (1) anomalies where the metal loss is greater than 80 percent of nominal wall thickness; (2) metal loss anomalies with a predicted failure pressure less than or equal to 1.1 times the MAOP; (3) a topside dent that has metal loss, cracking, or a stress riser; (4) anomalies where there is an indication of metal loss affecting certain longitudinal seams; and (5) cracks or crack-like anomalies meeting specified criteria.

The final rule also designates the following types of defects as 1-year conditions: (1) smooth topside dents with a depth greater than 6 percent of the pipeline diameter; (2) dents greater than 2 percent of the pipeline diameter that are located at a girth weld or spiral seam weld; (3) a bottom-side dent that has metal loss, cracking, or a stress riser; (4) metal loss anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure ratio less than or equal to 1.39 for Class 2 locations, and 1.50 for Class 3 locations and Class 4 locations; (5) anomalies where there is metal loss that is at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld, and that has a predicted failure pressure less than 1.39 in Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, and less than 1.50 times the MAOP in all other Class 2 locations and all Class 3 and 4 locations; (6) anomalies where there is metal loss affecting a longitudinal seam; and (7) any indications of cracks or crack-like defects other than those listed as an immediate condition.

In this final rule, PHMSA is also adding requirements for addressing regulatory gaps related to the methods for calculating predicted failure pressure if metal loss exceeds 80 percent of wall thickness; time-sensitive integrity threats including corrosion affecting a longitudinal seam, especially those associated with seam types that are known to be susceptible to latent manufacturing defects, such as the failed pipe at San Bruno,[53] and selective seam weld corrosion; and the fact that the current regulations do not list SCC as an immediate condition even though it is listed in ASME/ANSI B31.8S as an immediate repair condition.

With respect to SCC, PHMSA has incorporated repair criteria to specify that operators must use engineering assessment techniques specified in § 192.712 to evaluate if cracks or crack-like anomalies should be categorized as an ''immediate'' condition, a ''1-year'' condition, or a ''monitored'' condition. PHMSA believes that this will help address NTSB recommendation P–12–3, which resulted from the investigation of the Enbridge accident near Marshall, MI.[54] Although the NTSB recommendation was specifically made for hazardous liquid pipelines regulated under part 195, SCC can affect gas transmission pipelines regulated under part 192 as well.

The current regulations do not include 1-year conditions for metal loss anomalies. For non-immediate conditions, the regulations direct operators to use Figure 4 in ASME/ANSI B31.8S to determine the repair criteria for metal loss anomalies that do not meet the ''immediate'' threshold. To address this gap, PHMSA is including certain metal loss anomalies in the list of 1-year conditions. These changes make the gas transmission repair criteria more consistent with the hazardous liquid repair criteria at 49 CFR 195.452(h).

PHMSA is also incorporating safety factors commensurate with the class location in which the pipeline is located to make 1-year conditions anomalies where the predicted failure pressure is less than or equal to 1.39 times MAOP in Class 2 locations, and 1.50 times MAOP in Class 3 and Class 4 locations in HCAs. Operators must continue to use ASME/ANSI B31.8S, Figure 4 for corrosion metal loss anomalies in Class 1 locations.

Additionally, the NTSB recommended that PHMSA revise the ''discovery of condition'' at 49 CFR 195.452(h)(2) to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify PHMSA and provide an expected date when adequate information will become available.[55] PHMSA incorporated this NTSB recommendation into §§ 195.416(f) and 195.452(h)(2) of the ''Safety of Hazardous Liquid Pipelines'' final rule, which was published on October 1, 2019.[56]

Although the NTSB made the recommendation for hazardous liquid pipelines regulated under part 195, the issue applies to gas transmission pipelines regulated under part 192 as well. Accordingly, PHMSA has

[53] These seam types include seams formed by direct current, low- or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.25 times the MAOP.

[54] See NTSB Recommendation P–12–3, available at *https://www.ntsb.gov/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-003.*

[55] NTSB Recommendation P–12–4, available at *https://www.ntsb.gov/safety/safety-recs/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-004.*

[56] See 84 FR 52260.

amended paragraph (b) of § 192.933 to require that operators notify PHMSA whenever the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline within 180 days of completing the assessment.

PHMSA is also finalizing requirements for the *in situ* evaluation of cracks and crack-like defects using in-the-ditch tools whenever an operator discovers conditions that need to be repaired, such as when an ILI, an SCCDA, a pressure test failure, or another assessment identifies such anomalies. This applies to IM pipelines the same requirement adopted in § 192.714(g) for non-IM pipelines.

Section 192.935 What additional preventive and mitigative measures must an operator take?

Section 192.935 requires an operator to take additional measures beyond those already required by part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in an HCA. An operator must conduct a risk analysis to identify the additional measures to protect the HCA and improve public safety. As discussed earlier, PHMSA is amending § 192.917 to clarify the guidance for risk analyses operators use to evaluate and select additional P&M measures. This final rule also adds specific enhanced measures for operators to use for managing internal and external corrosion in HCAs and expands the list of P&M measures operators must consider when providing for public safety.

Specifically, operators must explicitly consider the following P&M measures:

(i) Correcting the root causes of past incidents in order to prevent recurrence;

(ii) O&M processes that maintain safety and the pipeline MAOP;

(iii) Adequate resources for the successful execution of these activities within the required timeframe;

(iv) Pressure transmitters that communicate with the pipeline control center on both sides of automatic shut-off valves and remote-control valves;

(v) Additional right-of-way patrols;

(vi) Hydrostatic tests in areas where pipeline material has quality issues or records that are not traceable, verifiable, and complete;

(vii) Tests to determine unknown material, mechanical, or chemical properties that are needed to ensure pipeline integrity or substantiate MAOP, including material property tests from removed pipe that is representative of the in-service pipeline;

(viii) The re-coating of damaged, poorly performing, or disbonded coatings, and

(ix) Additional depth-of-cover surveys at roads, streams, and rivers, among other areas.

These P&M measures do not alter the fundamental requirement for operators to identify and implement P&M measures; rather, they provide additional guidance and clarify PHMSA's expectations with this important aspect of IM.

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. In the 2019 Gas Transmission Rule, PHMSA revised § 192.917 to include seismicity as a potential threat for operators to identify and evaluate. In this final rule, PHMSA is revising this section to require operators consider the seismicity of the area when evaluating additional P&M measures against the threat of outside force damage.

Section 192.941 What is a low stress reassessment?

Section 192.941 specifies that, to address the threat of external corrosion on cathodically protected pipe in an HCA segment, an operator must perform an electrical survey (*i.e.,* with an indirect examination tool or method) at least every 7 years. In this final rule, PHMSA is replacing the term ''electrical survey'' with ''indirect assessment'' to accommodate other techniques that are comparably effective.

V. Standards Incorporated by Reference

A. Summary of New and Revised Standards

Consistent with the amendments in this document, PHMSA is incorporating by reference into the PSR several standards as described below. Some of these standards are already incorporated by reference into the PSR and are being extended to other sections of the regulations. Other standards provide a technical basis for corresponding regulatory changes in this final rule.

- NACE Standard Practice 0204–2008, ''Stress Corrosion Cracking (SCC) Direct Assessment Methodology'' (Sept. 18, 2008).

This standard addresses the situation in which a portion of a pipeline has been identified as an area of interest with respect to SCC based on its history, operations, and risk assessment process, and it has been decided that direct assessment is an appropriate approach for integrity assessment. The incorporation of this standard into the PSR would provide guidance for managing SCC through the selection of potential pipeline segments, selecting dig sites within those segments, inspecting the pipe, collecting and analyzing data during the dig, establishing a mitigation program, defining the re-evaluation interval, and evaluating the effectiveness of the SCCDA process.

- NACE Standard Practice 0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas'' (DG–ICDA) (Dec. 1, 2006).

This standard practice formalizes an internal corrosion direct assessment method (DG–ICDA) that can be used to help ensure pipeline integrity for pipelines carrying normally dry natural gas. The method is applicable to natural gas pipelines that normally carry dry gas but that may suffer from infrequent, short-term upsets of liquid water (or other electrolyte). This standard is intended for use by pipeline operators and others who manage pipeline integrity. The basis of DG–ICDA is a detailed examination of locations along a pipeline where water would first accumulate and provides information about the downstream condition of the pipeline. If the locations along a length of pipe most likely to accumulate water have not corroded, other downstream locations less likely to accumulate water may be considered free from corrosion. The presence of extensive corrosion found at many locations during the evaluation suggests that the transported gas was not normally dry, and this standard would not be considered applicable.

- ASME/ANSI B31.8S–2004, ''Supplement to B31.8 on Managing System Integrity of Gas Pipelines'' (Jan. 14, 2005).

This standard covers onshore gas pipeline systems constructed with ferrous materials, including pipe, valves, appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. ASME/ANSI B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective IM program using proven industry practices and processes. Effective system management can decrease repair and replacement costs, prevent malfunctions, and minimize system downtime.

The incorporation by reference of ASME/ANSI B31.8S–2004 was approved for §§ 192.921 and 192.937 as of January 14, 2004. That approval is unaffected by the section revisions in this final rule.

- ANSI/NACE Standard Practice 0502–2010, ''Pipeline External Corrosion Direct Assessment Methodology'' (June 24, 2010).

This standard covers the NACE external corrosion direct assessment (ECDA) process, which assesses and

reduces the impact of external corrosion on pipeline integrity. ECDA is a continuous-improvement process providing the advantages of locating areas where defects can form in the future, not just areas where defects have already formed, thereby helping to prevent future external corrosion damage. This standard covers the four components of ECDA: Pre-Assessment, Indirect Inspections, Direct Examinations, and Post-Assessment.

The incorporation by reference of ANSI/NACE Standard Practice 0502–2010 was approved for §§ 192.923, 192.925, 192.931, 192.935, and 192.939 as of March 6, 2015. That approval is unaffected by the section revisions in this final rule.

The incorporation by reference of R–STRENG and ASME/ANSI B31G in certain sections of this rule was approved July 1, 2020, and remains unaffected by the revisions in this final rule.

B. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 80 standards and specifications developed and published by standard developing organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices.

The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104–113; NTTAA) directs Federal agencies to use standards developed by voluntary consensus standards bodies in lieu of government-written standards whenever possible. Voluntary consensus standards bodies develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, the Office of Management and Budget (OMB) issued Circular A–119 to implement section 12(d) of the NTTAA relative to the utilization of consensus technical standards by Federal agencies.[57] This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in the NTTAA.

Accordingly, PHMSA has the responsibility for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to the PSR. Revisions to materials incorporated by reference in the PSR are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

Pursuant to 49 U.S.C. 60102(p), PHMSA may not issue PSR amendments that incorporate by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge. Further, the Office of the Federal Register issued a rulemaking on November 7, 2014, revising 1 CFR 51.5(b) to require that agencies detail in the preamble of a final rulemaking the ways the materials it incorporates by reference are reasonably available to interested parties, and how interested parties can obtain those materials.[58]

To meet its statutory obligation for this rulemaking, PHMSA negotiated agreements with SDOs to provide free online access to standards that are incorporated by reference or proposed to be incorporated by reference. PHMSA will also provide individual members of the public temporary access to any standard that is incorporated by reference. Requests for access can be sent to the following email address: *phmsaphpstandards@dot.gov;* please include your phone number, physical address, and an email address and PHMSA will respond within 5 business days and provide access to the standard. PHMSA also notes that standards incorporated by reference in the PSR can be obtained from the organization developing each standard. Section 192.7 provides the contact information for each of those standard-developing organizations.

VI. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the existing authorities of the Secretary of Transportation delegated to the PHMSA Administrator pursuant to 49 CFR 1.97. Among the statutory authorities delegated to PHMSA are section 60102 of the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*) (authorizing issuance of regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities) and section 28 of the Mineral Leasing Act, as amended (30 U.S.C. 185(w)(3)). For a complete listing of authorities, see 49 CFR 1.97.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866 (''Regulatory Planning and Review'')[59] requires that agencies ''should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.'' Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, Executive Order 12866 requires that agencies ''should maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.'' Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts. The Federal Pipeline Safety Statutes at 49 U.S.C. 60102(b)(5) further authorize only those safety requirements whose benefits (including safety and environmental benefits) have been determined to justify their costs.

This action has been determined to be significant under Executive Order 12866. It is also considered significant under DOT Order 2100.6A because of significant congressional, State, industry, and public interest in pipeline safety. The final rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866 and is consistent with the requirements of Executive Order 12866, 49 U.S.C. 60102(b)(5), and DOT Order 2100.6. The Office of Information and Regulatory Affairs (OIRA) has not designated this rule as a ''major rule'' as defined by the Congressional Review Act (5 U.S.C. 801 *et seq.*).

Executive Order 12866 and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which also reinforces requirements for notice and comment under the Administrative Procedure Act (5 U.S.C. 551 *et seq.*). Therefore, in the NPRM, PHMSA sought public comment on its proposed revisions to the PSR and the preliminary cost and benefit analyses in the PRIA, as

[57] 81 FR 4673 (Jan. 27, 2016).

[58] 79 FR 66278.

[59] 58 FR 51735 (Oct. 4, 1993).

well as any information that could assist in quantifying the costs and benefits of this rulemaking. Those comments are addressed in this final rule, and additional discussion about the costs and benefits of the final rule are provided within the RIA posted in the rulemaking docket.

The table below summarizes the annualized costs for the provisions in the final rule. These estimates reflect the timing of the compliance actions taken by operators and are annualized, where applicable, over 20 years and discounted using rates of 3 percent and 7 percent. PHMSA estimates incremental costs for the final requirements in section 5 of the RIA. The costs of this final rule reflect MOC process improvements, additional corrosion control requirements, programmatic changes related to inspections following extreme weather events, and compliance with the revised repair criteria. PHMSA finds that the other final rule requirements will not result in an incremental cost. PHMSA estimates the annualized cost of this rule is $16.7 million at a 7 percent discount rate.

TABLE 1—ANNUALIZED COST OF THE FINAL RULE, YEAR 1–YEAR 20

[$2019 USD thousands]

Provision	Discount rate	
	3%	7%
Integrity Management Process Improvements *	$0	$0
Management of Change Process Improvements	1,194	1,223
Corrosion Control	8,662	8,998
Extreme Weather	55	78
Repair Criteria	2,725	6,357
Total	12,637	16,656

* No incremental costs are estimated for this topic area.

The benefits of the final rule consist of improved safety and avoided environmental harms (including greenhouse gas emissions) from reduction of risk of incidents on natural gas pipelines and will depend on the degree to which compliance actions result in additional safety measures, relative to the baseline, and the effectiveness of these measures in preventing or mitigating future pipeline releases or other incidents. PHMSA changed its benefit analysis approach for the RIA relative to the PRIA. The PRIA quantified and monetized the NPRM's benefits, while the RIA does not monetize this final rule's benefits. PHMSA chose not to monetize benefits in the RIA based on the public comments received in response to the PRIA and the uncertainty associated with quantifying changes in incident rates that can be explicitly attributed to the final rule's provisions.

For more information, please see the RIA posted in the rulemaking docket.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the APA unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. This final rule was developed in accordance with Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'') [60] to promote compliance with the Regulatory Flexibility Act and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA prepared a FRFA, which is available in the docket for the rulemaking. In it, PHMSA certifies that the rule will not have a significant impact on a substantial number of small entities.

D. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this final rule per the principles and criteria in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'') [61] and DOT Order 5301.1 (''Department of Transportation Policies, Programs, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Executive Order 13175 requires agencies to assure meaningful and timely input from Tribal Government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities or the relationship and distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the rulemaking and determined that it would not significantly or uniquely affect Tribal communities or Tribal governments. The rulemaking's regulatory amendments are facially neutral and would have broad, national scope; PHMSA, therefore, does not expect this rulemaking to significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or mandate Tribal action. And insofar as PHMSA expects the rulemaking will improve transmission pipeline safety and environmental risks, PHMSA does not expect it would entail disproportionately high adverse risks for Tribal communities. PHMSA also received no comments alleging ''substantial direct compliance costs'' or ''substantial direct effects'' on Tribal communities and Governments. For these reasons, PHMSA has determined the funding and consultation requirements of Executive Order 13175 and DOT Order 5301.1 do not apply.

E. Paperwork Reduction Act

Under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), no person is required to respond to an information collection unless it has been approved by OMB and displays a valid OMB control number. Pursuant to implementing regulations at 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests.

On April 8, 2016, PHMSA published an NPRM seeking public comments on proposed revisions of the PSR

[60] 68 FR 7990 (Feb. 19, 2003).

[61] 65 FR 67249 (Nov. 6, 2000).

applicable to the safety of gas transmission pipelines and gas gathering pipelines. Based on the provisions in the NPRM, PHMSA proposed corresponding changes to information collections. PHMSA determined it would be more effective to first advance a rulemaking that focused on the mandates from the 2011 Pipeline Safety Act and subsequently split out the other provisions contained in the NPRM into three separate rules. As such, in this rulemaking, PHMSA has removed all references to the changes in the information collections covered in those other rulemakings. PHMSA will submit information collection revision requests to OMB based on the requirements contained within this final rule.

PHMSA estimates that the proposals in this final rule will involve new and amended information collections as described below. The following information is provided for each information collection: (1) title of the information collection; (2) OMB control number; (3) current expiration date; (4) type of request; (5) abstract of the information collection activity; (6) description of affected public; (7) estimate of total annual reporting and recordkeeping burden; and (8) frequency of collection. Relevant information collections consist of the following:

1. Title: Record Keeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 3/31/2025.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation upon request. Based on the proposed revisions in this final rule, 16 new recordkeeping requirements are being added to the pipeline safety regulations for owners and operators of gas transmission pipelines. PHMSA expects these new mandatory recordkeeping requirements to result in 1,902 responses and 9,530 burden hours.

Affected Public: Gas Transmission Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,863,374.

Total Annual Burden Hours: 1,686,560.

Frequency of Collection: On occasion.

2. Title: Notification Requirements for Gas Transmission Pipelines.

OMB Control Number: 2137–0636.

Current Expiration Date: 01/31/2023.

Abstract: A person owning or operating a natural gas pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request in accordance with 49 U.S.C. 60117. The regulations in 49 CFR part 192 require operators to make various notifications upon the occurrence of certain events. Based on the proposed revisions in this final rule, 6 new notification requirements are being added to the PSR for owners and operators of gas transmission pipelines. PHMSA expects these revisions to result in 268 additional responses and 290 additional burden hours for this information collection. These mandatory notification requirements are necessary to ensure safe operation of transmission pipelines, ascertain compliance with gas pipeline safety regulations, and to provide a background for incident investigations.

Affected Public: Gas Transmission Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 990.

Total Annual Burden Hours: 1,360.

Frequency of Collection: On occasion.

3. Title: Annual Reports for Gas Pipeline Operators

OMB Control Number: 2137–0522.

Current Expiration Date: 3/31/2025.

Abstract: This information collection covers the collection of annual report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission and Gas Gathering Annual Report (form PHMSA F7 100.2–1) to collect more granular data on conditions being repaired outside of HCA segments. Operators currently provide the number of anomalies outside of HCAs based on assessment methods, however, PHMSA requires operators to further categorize the data in accordance with 49 CFR 192.713. Based on the proposed revisions, PHMSA estimates that it will take an additional 30 minutes per report to include the newly required data—increasing the burden for completing each annual report to 47.5 hours. This change results in an overall burden increase of 905 hours for this information collection.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,053.

Total Annual Burden Hours: 95,521.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue, SE, Washington, DC 20590–0001, Telephone (202) 366–4595.

F. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more in 1996 dollars in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate.

As explained in the RIA, PHMSA determined that this final rule does not impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more (in 1996 dollars) in any one year. A copy of the RIA is available for review in the docket.

G. National Environmental Policy Act

The National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.,* NEPA), requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA has completed its NEPA analysis. Based on the environmental assessment, PHMSA determined that an environmental impact statement is not required for this rulemaking because it will not have a significant impact on the human environment. The final EA and Finding of No Significant Impact have been placed into the docket addressing the comments received.

H. Executive Order 13132

PHMSA analyzed this final rule in accordance with Executive Order 13132 (''Federalism'').[62] Executive Order

[62] 64 FR 43255 (Aug.10, 1999).

13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

The final rule does not have a substantial direct effect on the State and local governments, the relationship between the Federal Government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. Section 60104(c) of the Federal Pipeline Safety Statutes prohibits certain State safety regulation of interstate pipelines. Under the Federal Pipeline Safety Statutes, States can augment pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate. In this instance, the preemptive effect of the final rule is limited to the minimum level necessary to achieve the objectives of the pipeline safety laws under which the final rule is promulgated. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

I. Executive Order 13211

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') [63] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Executive Order 13211 defines a ''significant energy action'' as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation that (1)(i) is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy (including a shortfall in supply, price increases, and increased use of foreign supplies); or (2) is designated by the Administrator of the OIRA as a significant energy action.

This final rule is a significant action under Executive Order 12866; however, it is expected to have an annual effect on the economy of less than $100 million. Further, this action is not likely to have a significant adverse effect on the supply, distribution, or use of energy in the United States. The Administrator of OIRA has not designated the final rule as a significant energy action. For additional discussion of the anticipated economic impact of this rulemaking, please review the RIA posted in the rulemaking docket.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement [64] at: *https://www.govinfo.gov/content/pkg/FR-2000-04-11/pdf/00-8505.pdf.*

K. Executive Order 13609 and International Trade Analysis

Executive Order 13609 (''Promoting International Regulatory Cooperation'') [65] requires agencies consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA participates in the establishment of international standards to protect the safety of the American public. PHMSA has assessed the effects of the rulemaking and determined that it will not cause unnecessary obstacles to foreign trade.

L. Environmental Justice

DOT Order 5610.2(b) and Executive Orders 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[66] 13985 (''Advancing Racial Equity and Support for Underserved Communities Through the Federal Government''),[67] 13990 (''Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis''),[68] and 14008 (''Tackling the Climate Crisis at Home and Abroad'') [69] require DOT operational administrations to achieve environmental justice as part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects, including interrelated social and economic effects, of their programs, policies, and activities on minority populations, low-income populations, and other underserved disadvantaged communities.

PHMSA has evaluated this final rule under DOT Order 5610.2(b) and the Executive Orders listed above and determined it would not cause disproportionately high and adverse human health and environmental effects on minority populations, low-income populations, and other underserved and disadvantaged communities. The rulemaking is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to adversely impact any particular population, region, or community. And insofar as PHMSA expects the rulemaking would reduce the safety and environmental risks associated with natural gas transmission pipelines, many of which are located in the vicinity of environmental justice communities,[70] PHMSA expects the regulatory amendments introduced by this final rule would reduce adverse human health and environmental risks for minority populations, low-income populations, and other underserved and other disadvantaged communities in the vicinity of those pipelines. Lastly, as

[63] 66 FR 28355 (May 18, 2001).

[64] 65 FR 19476 (Apr. 11, 2000).

[65] 77 FR 26413 (May 4, 2012).

[66] 59 FR 7629 (Feb. 16, 1994).

[67] 86 FR 7009 (Jan. 20, 2021).

[68] 86 FR 7037 (Jan. 20, 2021).

[69] 86 FR 7619 (Feb. 1, 2021).

[70] See Ryan Emmanuel, et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5:6 GeoHealth (June 2021), *https://agupubs.onlinelibrary.wiley.com/toc/24711403/2021/5/6* (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

explained in the final EA, PHMSA expects that the regulatory amendments in this final rule will yield GHG emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority, low-income, underserved, and other disadvantaged populations and communities.

List of Subjects in 49 CFR Part 192

Corrosion control, Incorporation by reference, Installation of pipe in a ditch, Integrity management, Internal inspection device, Management of change, Pipeline safety, Repair criteria, Surveillance.

In consideration of the foregoing, PHMSA amends 49 CFR part 192 as follows:

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. In § 192.3:
■ a. Add definitions for ''Close interval survey'', ''Distribution center'', ''Dry gas or dry natural gas'', ''Hard spot'', ''In-line inspection (ILI)'', and ''In-line inspection tool or instrumented internal inspection device'' in alphabetical order;
■ b. Revise the definition for ''Transmission line''; and
■ c. Add the definition ''Wrinkle bend'' in alphabetical order.

The additions and revision read as follows:

§ 192.3 Definitions.

* * * * *

Close interval survey means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.

* * * * *

Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example:

(1) At a metering location;

(2) A pressure reduction location; or

(3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

* * * * *

Dry gas or dry natural gas means gas above its dew point and without condensed liquids.

* * * * *

Hard spot means an area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV_{10}).

* * * * *

In-line inspection (ILI) means an inspection of a pipeline from the interior of the pipe using an inspection tool also called *intelligent* or *smart pigging.* This definition includes tethered and self-propelled inspection tools.

In-line inspection tool or *instrumented internal inspection device* means an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an *intelligent* or *smart pig.*

* * * * *

Transmission line means a pipeline or connected series of pipelines, other than a gathering line, that:

(1) Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;

(2) Has an MAOP of 20 percent or more of SMYS;

(3) Transports gas within a storage field; or

(4) Is voluntarily designated by the operator as a transmission pipeline.

Note 1 to *transmission line.* A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

* * * * *

Wrinkle bend means a bend in the pipe that:

(1) Was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

(i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or

(ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.

(2)(i) If the length of the wrinkle bend cannot be reliably determined, then wrinkle bend means a bend in the pipe where (h/D)*100 exceeds 2 when S is less than 37,000 psi (255 MPa), where (h/D)*100 exceeds for psi [for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where (h/D)*100 exceeds 1 when S is 47,000 psi (324 MPa) or more.

(ii) Where:

(A) D = Outside diameter of the pipe, in. (mm);

(B) h = Crest-to-trough height of the ripple, in. (mm); and

(C) S = Maximum operating hoop stress, psi (S/145, MPa).

■ 3. In § 192.7:
■ a. Revise paragraphs (a) and (c)(6);
■ b. Redesignate paragraph (h)(1) as paragraph (h)(4) and paragraph (h)(2) as paragraph (h)(1);
■ c. Add new paragraph (h)(2) and paragraph (h)(3); and
■ d. Revise newly redesignated paragraph (h)(4).

The revisions and additions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All approved material is available for inspection at the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590, 202–366–4046, *https://www.phmsa.dot.gov/pipeline/regs,* and at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fr.inspection@nara.gov,* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.* It is also available from the sources in the following paragraphs of this section.

* * * * *

(c) * * *

(6) ASME/ANSI B31.8S–2004, ''Supplement to B31.8 on Managing System Integrity of Gas Pipelines,'' approved January 14, 2005, (ASME/ANSI B31.8S), IBR approved for §§ 192.13(d); 192.714(c) and (d); 192.903 note to *potential impact radius;* 192.907 introductory text and (b); 192.911 introductory text, (i), and (k) through (m); 192.913(a) through (c); 192.917(a) through (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b) and (c); 192.929(b); 192.933(c) and (d); 192.935(a) and (b); 192.937(c); 192.939(a); and 192.945(a).

* * * * *

(h) * * *

(2) NACE SP0204–2008, Standard Practice, ''Stress Corrosion Cracking (SCC) Direct Assessment Methodology,'' reaffirmed September 18, 2008, (NACE SP0204); IBR approved for §§ 192.923(b); 192.929(b) introductory text, (b)(1) through (3), (b)(5) introductory text, and (b)(5)(i).

(3) NACE SP0206–2006, Standard Practice, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG–ICDA),'' approved December 1, 2006, (NACE SP0206), IBR approved for §§ 192.923(b); 192.927(b), (c) introductory text, and (c)(1) through (4).

(4) ANSI/NACE SP0502–2010, Standard Practice, ''Pipeline External Corrosion Direct Assessment Methodology,'' revised June 24, 2010, (NACE SP0502), IBR approved for §§ 192.319(f); 192.461(h); 192.923(b); 192.925(b); 192.931(d); 192.935(b); and 192.939(a).

* * * * *

■ 4. In § 192.9, paragraphs (b), (c), (d)(1) and (2), and (e)(1)(i) and (ii) are revised to read as follows:

§ 192.9 What requirements apply to gathering pipelines?

* * * * *

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c) 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part. However, an operator of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N of this part by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) * * *

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§ 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;

* * * * *

(e) * * *

(1) * * *

(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B through G and J of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(ii) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§ 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;

* * * * *

■ 5. In § 192.13, paragraph (d) is added to read as follows:

§ 192.13 What general requirements apply to pipelines regulated under this part?

* * * * *

(d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a management of change process. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11 (incorporated by reference, *see* § 192.7), that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. For pipeline segments other than those covered in subpart O of this part, this management of change process must be implemented by February 26, 2024. The requirements of this paragraph (d) do not apply to gas gathering pipelines. Operators may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this section, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

■ 6. In § 192.18, paragraph (c) is revised to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, § 192.9, § 192.13, § 192.179, § 192.319, § 192.461, § 192.506, § 192.607, § 192.619, § 192.624, § 192.632, § 192.634, § 192.636, § 192.710, § 192.712, § 192.714, § 192.745, § 192.917, § 192.921, § 192.927, § 192.933, or § 192.937, a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* ''other technology'' or ''alternative equivalent technology'') than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

■ 7. In § 192.319, paragraphs (d) through (g) are added to read as follows:

§ 192.319 Installation of pipe in a ditch.

* * * * *

(d) Promptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the

Exhibit TRA-3

pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

(e) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (d) of this section.

(f) An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* § 192.7) within 6 months after the pipeline is placed in service, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

(g) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (d) through (f) of this section.

■ 8. In § 192.461, paragraph (a)(4) is revised and paragraphs (f) through (i) are added to read as follows:

§ 192.461 External corrosion control: Protective coating.

(a) * * *

(4) Have sufficient strength to resist damage due to handling (including, but not limited to, transportation, installation, boring, and backfilling) and soil stress; and

* * * * *

(f) Promptly after the backfill of an onshore steel transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), but no later than 6 months after the backfill, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

(g) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (f) of this section.

(h) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

(i) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (f) through (h) of this section.

■ 9. In § 192.465, the section heading and paragraph (d) are revised and paragraph (f) is added to read as follows:

§ 192.465 External corrosion control: Monitoring and remediation.

* * * * *

(d) Each operator must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of this section. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

* * * * *

(f) An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this part.

(1) Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes.

(2) To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of this section. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.

■ 10. In § 192.473, paragraph (c) is added to read as follows:

§ 192.473 External corrosion control: Interference currents.

* * * * *

(c) For onshore gas transmission pipelines, the program required by paragraph (a) of this section must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;

(3) Development of a remedial action plan to correct any instances where interference current is greater than or equal to 100 amps per meter squared or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and

(4) Application for any necessary permits within 6 months of completing the interference survey that identified

the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits.

■ 11. Section 192.478 is added to read as follows:

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) Each operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary. Potentially corrosive constituents include, but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and liquid water, either by itself or in combination. An operator must evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures as necessary.

(b) The monitoring and mitigation program described in paragraph (a) of this section must include:

(1) The use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents.

(2) Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects.

(3) An evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary.

■ 12. In § 192.485, paragraph (c) is revised to read as follows:

§ 192.485 Remedial measures: Transmission lines.

* * * * *

(c) *Calculating remaining strength.* Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with § 192.712.

■ 13. In § 192.613, paragraph (c) is added to read as follows:

§ 192.613 Continuing surveillance.

* * * * *

(c) Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(1) An operator must assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under this paragraph (c)(1).

(2) An operator must commence the inspection required by paragraph (c) of this section within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by paragraph (c)(1) of this section are available. If an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

(3) An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required by paragraph (c) of this section. Such actions might include, but are not limited to:

(i) Reducing the operating pressure or shutting down the pipeline;

(ii) Modifying, repairing, or replacing any damaged pipeline facilities;

(iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

(iv) Performing additional patrols, surveys, tests, or inspections;

(v) Implementing emergency response activities with Federal, State, or local personnel; or

(vi) Notifying affected communities of the steps that can be taken to ensure public safety.

■ 14. In § 192.710, paragraph (f) is revised as follows:

§ 192.710 Transmission lines: Assessments outside of high consequence areas.

* * * * *

(f) *Remediation.* An operator must comply with the requirements in §§ 192.485, 192.711, 192.712, 192.713, and 192.714, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

* * * * *

■ 15. In § 192.711, paragraph (b)(1) is revised to read as follows:

§ 192.711 Transmission lines: General requirements for repair procedures.

* * * * *

(b) * * *

(1)(i) Non-integrity management repairs for gathering lines and offshore transmission lines: For gathering lines subject to this section in accordance with § 192.9 and for offshore transmission lines, an operator must make permanent repairs as soon as feasible.

(ii) Non-integrity management repairs for onshore transmission lines: Except for gathering lines exempted from this section in accordance with § 192.9 and offshore transmission lines, after May 24, 2023, whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program under subpart O of this part, it must correct the condition as prescribed in § 192.714.

* * * * *

■ 16. In § 192.712, the section heading and paragraph (b) are revised and paragraphs (c) and (h) are added to read as follows:

§ 192.712 Analysis of predicted failure pressure and critical strain level.

* * * * *

(b) *Corrosion metal loss.* When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R–STRENG (incorporated by reference, *see* § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(1) If an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in

paragraph (b) introductory text, the operator must notify PHMSA in advance in accordance with § 192.18(c).

(2) The notification provided for by paragraph (b)(1) of this section must include a comparison of its predicted failure pressures to R–STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles.

(c) *Dents and other mechanical damage.* To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:

(1) Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion.

(2) Review high-resolution magnetic flux leakage (HR–MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections.

(3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.

(4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.

(5) Identify and quantify all previous and present significant loads acting on the dent.

(6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods.

(7) The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances.

(8) Dents with a depth greater than 10 percent of the pipe outside diameter or with geometric strain levels that exceed the lessor of 10 percent or exceed the critical strain for the pipe material properties must be remediated in accordance with § 192.713, § 192.714, or § 192.933, as applicable.

(9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of 5 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment.

(10) If the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in § 192.713, § 192.714, or § 192.933, as applicable.

(11) An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA, with the relevant procedures, in accordance with § 192.18.

* * * * *

(h) *Reassessments.* If an operator uses an engineering critical assessment method in accordance with paragraphs (c) and (d) of this section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:

(1) If the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with § 192.939(a), unless the safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

(2) If the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of 10 years in accordance with § 192.710(b), unless the anomaly safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

■ 17. Section 192.714 is added to read as follows:

§ 192.714 Transmission lines: Repair criteria for onshore transmission pipelines.

(a) *Applicability.* This section applies to onshore transmission pipelines not subject to the repair criteria in subpart O of this part, and which do not operate under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620. Pipeline segments that are located in high consequence areas, as defined in § 192.903, must comply with the applicable actions specified by the integrity management requirements in subpart O. Pipeline segments operating under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620 must comply with § 192.620(d)(11).

(b) *General.* Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through § 192.607.

(c) *Schedule for evaluation and remediation.* An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless paragraph (d) of this section provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in paragraph (d) of this section in an onshore steel transmission pipeline must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe that will permanently restore the pipeline's MAOP based on the use of § 192.105 and the design factors for the class location in which it is located; or

(2) Repaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure pressure times the design factor for the class location in which it is located.

(d) *Remediation of certain conditions.* For onshore transmission pipelines not located in high consequence areas, an operator must remediate a listed condition according to the following criteria:

(1) *Immediate repair conditions.* An operator must repair the following conditions immediately upon discovery:

(i) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly

shows a predicted failure pressure, determined in accordance with § 192.712(b), of less than or equal to 1.1 times the MAOP.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

(2) *Two-year conditions.* An operator must repair the following conditions within 2 years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower ⅓ of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iv) For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b) at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4, as specified in paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions.* An operator must record and monitor the following conditions during subsequent risk assessments and integrity assessments for any change that may require remediation.

(i) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom ⅓ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with § 192.712(c) determines that critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties.

(iv) A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *Temporary pressure reduction.* (1) Immediately upon discovery and until an operator remediates the condition specified in paragraph (d)(1) of this section, or upon a determination by an

operator that it is unable to respond within the time limits for the conditions specified in paragraph (d)(2) of this section, the operator must reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel:

(i) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(ii) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(iii) A level not exceeding the predicted failure pressure divided by 1.1.

(2) An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this section.

(3) When a pressure reduction, in accordance with paragraph (e) of this section, exceeds 365 days, an operator must notify PHMSA in accordance with § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(4) An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of 5 years after the pipeline has been repaired.

(f) *Other conditions.* Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules, and methods defined in the operator's operating and maintenance procedures.

(g) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. ''In situ'' examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

(h) *Determining predicted failure pressures and critical strain levels.* An operator must perform all determinations of predicted failure pressures and critical strain levels required by this section in accordance with § 192.712.

■ 18. In § 192.911, paragraph (k) is revised to read as follows:

§ 192.911 What are the elements of an integrity management program?

* * * * *

(k) A management of change process as required by § 192.13(d).

* * * * *

■ 19. In § 192.917, paragraphs (a) through (d) are revised to read as follows:

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 2, which are grouped under the following four threat categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Stable threats, such as manufacturing, welding, fabrication, or construction defects;

(3) Time independent threats, such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage, to include consideration of seismicity, geology, and soil stability of the area; and

(4) Human error, such as operational or maintenance mishaps, or design and construction mistakes.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4.

Operators must begin to integrate all pertinent data elements specified in this section starting on May 24, 2023, with all available attributes integrated by February 26, 2024. An operator may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (b), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety. An operator must gather and evaluate the set of data listed in paragraph (b)(1) of this section. The evaluation must analyze both the covered segment and similar non-covered segments, and it must:

(1) Integrate pertinent information about pipeline attributes to ensure safe operation and pipeline integrity, including information derived from operations and maintenance activities required under this part, and other relevant information, including, but not limited to:

(i) Pipe diameter, wall thickness, seam type, and joint factor;

(ii) Manufacturer and manufacturing date, including manufacturing data and records;

(iii) Material properties including, but not limited to, grade, specified minimum yield strength (SMYS), and ultimate tensile strength;

(iv) Equipment properties;

(v) Year of installation;

(vi) Bending method;

(vii) Joining method, including process and inspection results;

(viii) Depth of cover;

(ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;

(x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;

(xi) Pipe coating methods (both manufactured and field applied), including the method or process used to apply girth weld coating, inspection reports, and coating repairs;

(xii) Soil, backfill;

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(xiii) Construction inspection reports, including but not limited to:

(A) Post backfill coating surveys; and

(B) Coating inspection (''jeeping'' or ''holiday inspection'') reports;

(xiv) Cathodic protection installed, including, but not limited to, type and location;

(xv) Coating type;

(xvi) Gas quality;

(xvii) Flow rate;

(xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

(xix) Class location;

(xx) Leak and failure history, including any in-service ruptures or leaks from incident reports, abnormal operations, safety-related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;

(xxi) Coating condition;

(xxii) Cathodic protection (CP) system performance;

(xxiii) Pipe wall temperature;

(xxiv) Pipe operational and maintenance inspection reports, including, but not limited to:

(A) Data gathered through integrity assessments required under this part, including, but not limited to, in-line inspections, pressure tests, direct assessments, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) CP rectifier readings;

(D) CP test point survey readings and locations;

(E) Alternating current, direct current, and foreign structure interference surveys;

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including, but not limited to, direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (*e.g.,* pipe and pipe coating condition, *see* § 192.459), including the results of any non-destructive examinations of the pipe, seam, or girth weld (*i.e.* bell hole inspections);

(H) Stress corrosion cracking excavations and findings;

(I) Selective seam weld corrosion excavations and findings;

(J) Any indication of seam cracking; and

(K) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(xxv) External and internal corrosion monitoring;

(xxvi) Operating pressure history and pressure fluctuations, including an analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(xxviii) Encroachments;

(xxix) Repairs;

(xxx) Vandalism;

(xxxi) External forces;

(xxxii) Audits and reviews;

(xxxiii) Industry experience for incident, leak, and failure history;

(xxxiv) Aerial photography; and

(xxxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area.

(2) Use validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SME), an operator must employ adequate control measures to ensure consistency and accuracy of information. Control measures may include training of SMEs or the use of outside technical experts (independent expert reviews) to assess the quality of processes and the judgment of SMEs. An operator must document the names and qualifications of the individuals who approve SME inputs used in the current risk assessment.

(3) Identify and analyze spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings or evidence of pipeline damage where overhead imaging shows evidence of encroachment).

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and that analyzes the identified threats and potential consequences of an incident for each covered segment. An operator must ensure the validity of the methods used to conduct the risk assessment considering the incident, leak, and failure history of the pipeline segments and other historical information. Such a validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the likelihood of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed for each covered segment in accordance with § 192.935 and periodically evaluate the integrity of each covered pipeline segment in accordance with § 192.937. Beginning February 26, 2024, the risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas;

(2) Analyze the likelihood of failure due to each individual threat and each unique combination of threats that interact or simultaneously contribute to risk at a common location;

(3) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

(4) Evaluate the potential risk reduction associated with candidate risk reduction activities, such as preventive and mitigative measures, and reduced anomaly remediation and assessment intervals.

(5) In conjunction with § 192.917(b), an operator may request an extension of up to 1 year for the requirements of this paragraph by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (c)(5), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S and consider any threats unique to the integrity of plastic pipe, such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

* * * * *

■ 20. In § 192.923, paragraphs (b)(2) and (3) are revised to read as follows:

§ 192.923 How is direct assessment used and for what threats?

* * * * *

(b) * * *

(2) Section 192.927 and NACE SP0206 (incorporated by reference, *see* § 192.7), if addressing internal corrosion (IC).

(3) Section 192.929 and NACE SP0204 (incorporated by reference, *see* § 192.7), if addressing stress corrosion cracking (SCC).

* * * * *

■ 21. In § 192.927, paragraphs (b) and (c) are revised to read as follows:

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

* * * * *

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206 (incorporated by reference, *see* § 192.7). The Dry Gas Internal Corrosion Direct Assessment (DG–ICDA) process described in this section applies only for a segment of pipe transporting normally dry natural gas (*see* § 192.3) and not for a segment with electrolytes normally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolytes present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to address internal corrosion effectively and must notify PHMSA in accordance with § 192.18. In the event of a conflict between this section and NACE SP0206, the requirements in this section control.

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that meets NACE SP0206 (incorporated by reference, *see* § 192.7) and that implements all four steps of the DG–ICDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. The plan must identify the locations of all ICDA regions within covered segments in the transmission system. An ICDA region is a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located to complete the assessment of the covered segment.

(1) *Preassessment.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7) in conducting the preassessment step of the ICDA process.

(2) *Indirect inspection.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7), and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. An operator must explicitly document the results of its feasibility assessment as required by NACE SP0206, section 3.3 (incorporated by reference, *see* § 192.7); if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use actual pipeline-specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of the data used to make those calculations, including, but not limited to, gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossings, river crossings, drains, valves, drips, etc.), topographical data, and depth of cover. An operator must select locations for direct examination and establish the extent of pipe exposure needed (*i.e.,* the size of the bell hole), to account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) *Detailed examination.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7) in conducting the detailed examination step of the ICDA process. When an operator first uses ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA region and must perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques that can examine for internal corrosion or other threats that are being assessed. One location must be the low point (*e.g.,* sag, drip, valve, manifold, dead-leg) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment, near the end of the ICDA region. Whenever corrosion is found during ICDA at any location, the operator must:

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933 if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.714 if the condition is not in a covered segment;

(ii) Expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined in accordance with paragraph (c)(3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region in which the corrosion was found and remediate identified instances of internal corrosion in accordance with either § 192.933 or §§ 192.485 and 192.714, as appropriate.

(4) *Post-assessment evaluation and monitoring.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7) in performing the post assessment step of the ICDA process. In addition to NACE SP0206, the evaluation and monitoring process must also include—

(i) An evaluation of the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within 1 year of conducting an ICDA;

(ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, then ICDA is not feasible for the segment); and

(iii) Continuous monitoring of each ICDA region that contains a covered segment where internal corrosion has been identified by using techniques such as coupons or ultrasonic (UT) sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart and risk factors specific to the ICDA region.

At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions, and remediate the conditions the operator finds in accordance with § 192.933 or §§ 192.485 and 192.714, as applicable.

(A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolytes might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

(5) *Other requirements.* The ICDA plan must also include the following:

(i) Criteria an operator will apply in making key decisions (including, but not limited to, ICDA feasibility, definition of ICDA regions and sub-regions, and conditions requiring excavation) in implementing each stage of the ICDA process; and

(ii) Provisions that the analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of § 192.933 may be limited to covered segments.

■ 22. Section 192.929 is revised to read as follows:

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking?

(a) *Definition.* A Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipeline segment for the presence of stress corrosion cracking (SCC) by systematically gathering and analyzing excavation data from pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method for addressing SCC in a covered pipeline segment must develop and follow an SCCDA plan that meets NACE SP0204 (incorporated by reference, *see* § 192.7) and that implements all four steps of the SCCDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. As specified in NACE SP0204, SCCDA is complementary with other inspection methods for SCC, such as in-line inspection or hydrostatic testing with a spike test, and it is not necessarily an alternative or replacement for these methods in all instances. Additionally, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered pipeline segments to identify whether the conditions for SCC are present and to prioritize the covered pipeline segments for assessment in accordance with NACE SP0204, sections 3 and 4, and Table 1 (incorporated by reference, *see* § 192.7). This process must also include gathering and evaluating data related to SCC at all sites an operator excavates while conducting its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204 (incorporated by reference, *see* § 192.7) indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (incorporated by reference, *see* § 192.7), and must include, at a minimum, all data listed in NACE SP0204, Table 2 (incorporated by reference, *see* § 192.7). Further, the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment, such as soil temperature, moisture, the presence or generation of carbon dioxide, or cathodic protection (CP);

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments;

(iii) The effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials;

(iv) The effects of coatings that shield CP when disbonded from the pipe; and

(v) Other factors that affect the mechanistic properties associated with SCC, including, but not limited to, historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) *Indirect inspection.* In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.

(3) *Direct examination.* In addition to NACE SP0204, the plan's procedures for direct examination must provide for an operator conducting a minimum of three direct examinations for SCC within the covered pipeline segment spaced at the locations determined to be the most likely for SCC to occur.

(4) *Remediation and mitigation.* If SCC is discovered in a covered pipeline segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section; or by grinding out the SCC defect and repairing the pipe. If an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with § 192.712 and that meets the design requirements of §§ 192.111 and 192.112, as applicable. The pipe and material properties an operator uses in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, an operator must base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607, if applicable.

(ii) Performing a spike pressure test in accordance with § 192.506 based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in

§ 192.506(a) divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with § 192.611; and 1.50 for all other Class 2 locations and all Class 3 and Class 4 locations. An operator must repair any test failures due to SCC by replacing the pipe segment and re-testing the segment until the pipe passes the test without failures (such as pipe seam or gasket leaks, or a pipe rupture). At a minimum, an operator must repair pipe segments that pass the pressure test but have SCC present by grinding the segment in accordance with paragraph (b)(4)(i) of this section.

(5) *Post assessment.* An operator's procedures for post-assessment, in addition to the procedures listed in NACE SP0204, sections 6.3, ''periodic reassessment,'' and 6.4, ''effectiveness of SCCDA,'' must include the development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as the mechanistic behavior of identified cracking. An operator's reassessment intervals must comply with § 192.939. The plan must include the following factors, in addition to any factors the operator determines appropriate:

(i) The evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, *see* § 192.7);

(ii) Conditions conducive to the creation of a carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions, including operating stress levels on the pipe;

(v) Cyclic loading conditions;

(vi) Mechanistic conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and

(ix) Disbonded coatings that shield CP from the pipe.

■ 23. In § 192.933, paragraphs (a) introductory text, (a)(1), (b), and (d) are revised and paragraph (e) is added read as follows:

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607.

(1) *Temporary pressure reduction.* (i) If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must reduce the operating pressure to one of the following:

(A) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(B) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(C) A level not exceeding the predicted failure pressure divided by 1.1.

(ii) An operator must determine the predicted failure pressure in accordance with § 192.712. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. The operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.

* * * * *

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period, the operator must notify PHMSA, in accordance with § 192.18, and provide an expected date when adequate information will become available. Notification to PHMSA does not alleviate an operator from the discovery requirements of this paragraph (b).

* * * * *

(d) *Special requirements for scheduling remediation*—(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 (incorporated by reference, *see* § 192.7) in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure,

determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraphs (d)(1) and (3) of this section, an operator must remediate any of the following within 1 year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower ⅓ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4, in accordance with paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with § 192.712(b), of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions.* An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:

(i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with § 192.712(c), of the dent and girth or seam weld demonstrate that critical strain levels are not exceeded.

(iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. ''In situ'' examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations

and fracture mechanics models for failure pressure determinations.

■ 24. In § 192.935, paragraphs (a) and (d)(3) are revised to read as follows:

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* (1) An operator must take additional measures beyond those already required by this part to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Such additional measures must be based on the risk analyses required by § 192.917. Measures that operators must consider in the analysis, if necessary, to prevent or mitigate the consequences of a pipeline failure include, but are not limited to:

(i) Correcting the root causes of past incidents to prevent recurrence;

(ii) Establishing and implementing adequate operations and maintenance processes that could increase safety;

(iii) Establishing and deploying adequate resources for the successful execution of preventive and mitigative measures;

(iv) Installing automatic shut-off valves or remote-control valves;

(v) Installing pressure transmitters on both sides of automatic shut-off valves and remote-control valves that communicate with the pipeline control center;

(vi) Installing computerized monitoring and leak detection systems;

(vii) Replacing pipe segments with pipe of heavier wall thickness or higher strength;

(viii) Conducting additional right-of-way patrols;

(ix) Conducting hydrostatic tests in areas where pipe material has quality issues or lost records;

(x) Testing to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations, including material property tests from removed pipe that is representative of the in-service pipeline;

(xi) Re-coating damaged, poorly performing, or disbonded coatings;

(xii) Performing additional depth-of-cover surveys at roads, streams, and rivers;

(xiii) Remediating inadequate depth-of-cover;

(xiv) Providing additional training to personnel on response procedures and conducting drills with local emergency responders; and

(xv) Implementing additional inspection and maintenance programs.

(2) Operators must document the risk analysis, the preventive and mitigative measures considered, and the basis for implementing or not implementing any preventive and mitigative measures considered, in accordance with § 192.947(d).

* * * * *

(d) * * *

(3) Perform instrumented leak surveys using leak detector equipment at least twice each calendar year, at intervals not exceeding 7 ½ months. For unprotected pipelines or cathodically protected pipe where electrical surveys are impractical, instrumented leak surveys must be performed at least four times each calendar year, at intervals not exceeding 4 ½ months. Electrical surveys are indirect assessments that include close interval surveys, alternating current voltage gradient surveys, direct current voltage gradient surveys, or their equivalent.

* * * * *

■ 25. In § 192.941, paragraph (b)(1) and the introductory text of paragraph (b)(2) are revised to read as follows:

§ 192.941 What is a low stress reassessment?

* * * * *

(b) * * *

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an indirect assessment on the covered segment at least once every 7 calendar years. The indirect assessment must be conducted using one of the following means: indirect examination method, such as a close interval survey; alternating current voltage gradient survey; direct current voltage gradient survey; or the equivalent of any of these methods. An operator must evaluate the cathodic protection and corrosion threat for the covered segment and include the results of each indirect assessment as part of the overall evaluation. This evaluation must also include, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where external corrosion assessments are impractical.* If an external corrosion assessment is impractical on the covered segment an operator must—

* * * * *

Issued in Washington, DC, on August 3, 2022, under authority delegated in 49 CFR 1.97.

Tristan H. Brown,

Deputy Administrator.

[FR Doc. 2022–17031 Filed 8–23–22; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2011–0023; Amdt. Nos. 191–30; 192–129]

RIN 2137–AF38

Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas gathering pipelines. This final rule addresses Congressional mandates, Government Accountability Office recommendations, and public input received as part of the rulemaking process. The amendments in this final rule extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. The rule does not affect offshore gas gathering pipelines.

DATES: The effective date of this final rule is May 16, 2022. The Director of the Federal Register approved the incorporation by reference of certain material listed in this rule as of April 14, 2006.

FOR FURTHER INFORMATION CONTACT:

Technical questions: Steve Nanney, Project Manager, by telephone at 713–272–2855.

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I. Executive Summary

A. Purpose of the Final Rule

This final rule responds to Government Accountability Office (GAO) recommendations and a Congressional mandate by extending existing design, operational and maintenance, and reporting requirements under the Federal Pipeline Safety Regulations to onshore natural gas gathering pipelines (''gathering lines'') in rural areas. Increasingly, many of these gathering lines have design and operating parameters that are similar to natural gas transmission lines (''transmission lines''), which pose an increased risk to public safety and the environment. PHMSA expects the regulatory amendments in this final rule will reduce the frequency and consequences of failures of onshore gas gathering lines and in turn reduce the likelihood of gas-related releases and incidents. The requirements in the final rule are designed to prevent and detect threats to pipeline integrity, improve public awareness of pipeline safety, and improve emergency response to pipeline incidents. PHMSA expects this final rule, therefore, will (1) improve public safety; (2) reduce threats to the physical environment (including, but not limited to, greenhouse gas emissions released during natural gas gathering line incidents); and (3) promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities.

Gas gathering lines are pipelines used to transport natural gas from a current production facility to a transmission line or distribution main lines (''main lines''). Generally, these pipelines are used to collect unprocessed gas from production facilities for transport to a gas treatment plant or other facility. From there, the natural gas is separated from petroleum liquids, water, and other impurities to prepare the gas for further transportation and sale. In the Federal Pipeline Safety Regulations (49 Code of Federal Regulations (CFR) parts 190 through 199), gas gathering lines are distinct from gas transmission pipelines which are defined in § 192.3 as pipelines that: (1) Transport gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center; (2) operate at a hoop stress of 20 percent or more of specified minimum yield strength (SMYS); [1] or (3) transport gas within a storage field.

Section 192.5 divides gas transmission and gathering lines into class locations based on the number of dwellings near the pipeline. These range from rural Class 1 to densely populated Class 4 locations. Class locations are defined in § 192.5. A Class 1 location is an offshore pipeline or an onshore pipeline that has 10 or fewer buildings intended for human occupancy within a 1-mile-long class-location unit. Unlike transmission lines, which are regulated regardless of location, gathering lines in rural Class 1 locations are exempt from Federal pipeline safety and reporting regulations in parts 191 and 192. However, PHMSA has authority under 49 U.S.C. 60102(a)(2) to issue safety regulations for pipeline transportation and pipeline facilities, including non-rural gathering lines and rural gathering lines designated by the Secretary as ''regulated gathering lines'' under 49 U.S.C. 60101(a)(21) and (b). Section 60117(b)(2) also authorizes DOT to require owners and operators of gathering lines, including rural gathering lines that have not been defined as regulated gathering lines, to submit information pertinent to its ability to make a determination as to whether and to what extent to regulate gathering lines.

Prior to 2005, U.S. gas production had been stagnant since a peak in the early 1970s.[2] The gathering lines that received gas from conventional wells typically had smaller diameters than gas transmission lines and operated at lower pressures. All else equal, a smaller diameter and lower pressure pipeline will release less gas and energy during an incident compared with a larger diameter pipeline with a greater operating pressure, such as a major transmission line. As a result, gathering lines located in Class 1 locations were

[1] SMYS is defined in § 192.3 and refers to the minimum force required to deform permanently the material as specified in the applicable design codes.

[2] *See* U.S. Energy Information Administration (EIA), ''Natural Gas Explained—U.S. natural gas consumption, dry production, and net imports, 1950–2019,'' *https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php* (accessed Nov. 3, 2020).

thought to pose relatively low risk to the public and the environment; therefore, gathering lines in Class 1 locations were exempt from reporting and safety requirements in the Federal Pipeline Safety Regulations. On the other hand, to account for the risks related to their physical, functional, and operational characteristics, transmission pipelines have been subject to PHMSA regulations regardless of their location.

Regardless of their size, regulated gathering lines are required to comply with safety reporting requirements and minimum safety standards in parts 191 and 192. Section 192.8(b) currently provides for two categories of regulated onshore gathering lines. Type A gathering lines are located in Class 2, Class 3, or Class 4 locations (see § 192.5) that operate at relatively higher stress levels. Section 192.9(c) subjects Type A regulated gathering lines to the same requirements as gas transmission pipelines, with a few exceptions, due to the high potential consequences of an incident on a high-stress pipeline in a populated area. Type B gathering lines are lower-stress pipelines in Class 3, Class 4, and certain Class 2 locations. Section 192.9(d) subjects Type B to a less comprehensive set of requirements since such pipelines operate at lower stress levels than transmission pipelines. As stated above, gathering lines in Class 1 locations are excluded from the reporting and safety standards contained in parts 191 and 192. In a 2006 final rule, PHMSA determined that the potential consequences of a release of a smaller-diameter pipeline with a lower maximum allowable operating pressure (''MAOP''), in a sparsely populated area, would be minimal.[3]

Due to new drilling technologies and changing demand factors, domestic gas production has been surging since approximately 2006.[4] Besides larger overall production volumes, new drilling technologies have also greatly increased the volume of gas that can be extracted from a single production site.[5] As a result, the volume of gas transported by gathering lines have also increased significantly. In order to transport this additional volume, some gas gathering lines are now constructed with large-diameter pipe and operating pressures comparable to large, interstate gas transmission pipelines. For example, the National Association of State Pipeline Safety Representatives (NAPSR)[6] Resolution 2010–2 AC–2 notes that members have observed rural gathering lines as large as 30 inches in diameter with a MAOP as high as 1480 psi.[7] The potential safety and environmental consequences of a gas pipeline rupture are proportional to the pipeline's diameter and operating pressure. Large diameter gathering lines are still exempt from the requirements in parts 191 and 192 if they are located in Class 1 locations despite their physical and functional similarities with transmission pipelines and their increased potential for adverse consequences in the event of incident.

Large diameter, high-pressure gathering lines are susceptible to the same types of integrity threats as transmission pipelines, including corrosion, excavation damage, and construction defects. The exemption of these pipelines from the safety requirements of the Federal Pipeline Safety Regulations failed to consider the present risks that now exist. In addition, PHMSA has lacked detailed information on the safety of gas gathering lines in Class 1 locations because such lines have been exempted from requirements to submit incident and annual reports under part 191. These reports are necessary for PHMSA to analyze how recent changes in the gas production and midstream industries affect the functional and operational characteristics of unregulated gathering lines, and the safety consequences of those changes. While more comprehensive information is being collected and analyzed, expanded regulatory measures are needed to protect the human and natural environment from the consequences of incidents on large-diameter, high-pressure gathering lines from preventable causes such as corrosion, excavation damage, and inadequate design and construction practices.

On August 25, 2011, PHMSA issued an advance notice of proposed rulemaking (ANPRM) that, among other things, requested comments with respect to improving the regulation of gas gathering lines.[8] Following the ANPRM's publication, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act, Pub. L. 112–90) was enacted on January 3, 2012. Section 21 of the 2011 Pipeline Safety Act mandated that DOT review existing regulations for gathering lines and report to Congress on the sufficiency of existing Federal and State laws and the need to modify or revoke existing exemptions from Federal regulation for gathering lines.

Subsequently, in 2012, the GAO issued recommendation GAO–12–388 for PHMSA to collect data on Federally unregulated hazardous liquid and gas gathering lines.[9] In August 2014, GAO issued recommendation 14–667 for PHMSA to ''move forward with rulemaking to address gathering pipeline safety that addresses the risks of larger-diameter, higher-pressure gathering pipelines, including subjecting such pipelines to emergency response planning requirements that currently do not apply to gathering pipelines.''[10]

On April 8, 2016, PHMSA issued a notice of proposed rulemaking (NPRM) responding to comments received on the ANPRM and proposing to further regulate gas gathering lines to enhance safety.[11] This final rule addresses only those portions of the NPRM dealing with gas gathering lines. Portions of the NPRM dealing with gas transmission issues have already been implemented in the final rule, ''Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments,'' (''Gas Transmission Final Rule'') published on October 1, 2019.[12] The remaining gas transmission issues will be addressed in the future in a separate rulemaking under the Regulatory Identifier Number (RIN) 2137–AF39, titled ''Pipeline Safety: Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments.''

The NPRM discussed the Congressional mandate and GAO recommendations, as well as the increased risk factors regarding gathering lines discussed above. In addition, the NPRM explained the need to clarify the definitions of gas gathering lines in §§ 192.3 and 192.8, which rely on American Petroleum Institute (API) Recommended Practice (RP) 80,

[3] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 FR 13289, 13291 (Mar. 15, 2006).

[4] EIA, ''U.S. Natural Gas Marketed Production,'' *https://www.eia.gov/dnav/ng/hist/n9050us2a.htm.* (accessed Nov. 9, 2020).

[5] EIA, ''Hydraulically fractured horizontal wells account for most new oil and natural gas wells,'' *https://www.eia.gov/todayinenergy/detail.php?id=34732* (Jan. 30, 2018).

[6] NAPSR is a nonprofit association of State pipeline safety officials.

[7] Available on the NAPSR website at *http://www.napsr.org/resolutions.html.*

[8] Pipeline Safety: Safety of Gas Transmission Pipelines, 76 FR 53086.

[9] GAO, No. 12–388, ''Pipeline Safety: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety'' (Mar. 22, 2012).

[10] GAO, No. 14–667, ''Oil and Gas Transportation: Department of Transportation Is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety'' at 48 (Aug. 2014).

[11] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 FR 20722.

[12] 84 FR 52180.

''Guidelines for the Definition of Onshore Gas Gathering Lines,'' first edition, April 2000. The current definitions are unclear with respect to each of (1) the point at which a non-jurisdictional production operation ends and a potentially regulated gas gathering line begins and (2) the use of the incidental gathering designation, which allows an operator to designate lines downstream from any gathering function defined in API RP 80 as a gathering line rather than as a transmission line.

A summary of the proposed changes and PHMSA's response to the comments on the NPRM are provided below in section III of this final rule.

On December 28, 2020, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (2020 PIPES Act, Pub. L. 116–260) was enacted. Section 112(a) directed PHMSA to issue a final rule in this rulemaking by March 27, 2021.

B. Summary of the Major Provisions of the Final Rule

This final rule addresses reporting and safety requirements for onshore gas gathering lines; offshore gas gathering lines are beyond the scope of this rulemaking.[13] The final rule requires operators of all onshore gas gathering lines to report incidents and file annual reports under part 191. The purpose of this expanded reporting obligation is to gather data about the state of gas gathering infrastructure and monitor the safety performance of gas gathering lines that were previously exempt from Federal reporting requirements. The information in the reports will help determine the need for future regulatory changes to address the risks to the public, property, and the environment posed by all types of pipeline systems engaged in the transportation of gas.

In addition, the final rule provides for a new Type C regulated gathering line[14] in § 192.8. Type C gathering lines are defined as gas gathering lines in Class 1 locations that have outer diameters of 8.625 inches or greater and operate at higher stress levels or pressures. The safety requirements for Type C lines, referred to as Type C requirements in the final rule, are specified in revised § 192.9(e) and vary based on the outer diameter of the pipeline and the potential consequences of a failure. The potential consequences of incidents are greater on larger-diameter, higher-pressure pipelines and pipelines that are located near buildings intended for human occupancy. Type C gathering lines with an outside diameter greater than 16 inches and certain other Type C gathering lines that could directly affect homes and other structures are required to comply with (1) existing requirements for Type B gas gathering lines, and (2) requirements at § 192.615 that operators develop and implement emergency plans. Type C gathering lines with smaller diameters or that could not directly affect homes and other structures have fewer requirements that are limited to damage prevention, emergency plans, and public awareness. These requirements address known causes of pipeline failures including excavation damage, corrosion, and inadequate design and construction standards.

C. Costs and Benefits

Consistent with 49 U.S.C. 60102(b) and Executive Order 12866 (''Regulatory Planning and Review''),[15] PHMSA has prepared an assessment of the benefits (including safety and environmental benefits) and costs of the final rule as well as reasonable alternatives. PHMSA expects benefits of the final rule to consist of improved safety and avoided environmental harms (including methane emissions) from reduction of the frequency and consequences of failures of onshore natural gas gathering lines that could result in releases and incidents. PHMSA estimates the annualized costs of the rule to be approximately $13.7 million per year at a 7-percent discount rate. The Regulatory Impact Analysis (RIA) for this final rule is available in the docket. The table below provides a summary of the estimated costs for the major provisions in this rulemaking and in total (see the RIA for further detail on these estimates).

Provision	Estimated annualized cost (7%)
Right-of-Way Surveillance	$170,087.
Corrosion Control	$2,043,260.
Damage Prevention	$285,011.
Public Awareness	$550,464.
Line Markers	$1,680,870.
Emergency Plan	$312,167.
Leakage Surveys	$7,626,075.
Incident reporting	$134,556.
Annual reporting	$943,408.
Construction	Negligible.
Total	$13,745,898.

II. Background

A. Detailed Overview

Introduction

The Pipeline Safety Regulations divide gas transmission and gathering lines into classes from Class 1 (rural areas) to Class 4 (densely populated, high-rise areas) that are based on the number of buildings or dwellings for human occupancy in the area. Class locations are defined in § 192.5. A Class 1 location is an offshore pipeline or an onshore pipeline that has 10 or fewer buildings intended for human occupancy within a 1-mile-long class-location unit. This final rule addresses only onshore gas gathering lines. Gas gathering lines located in Class 2, Class 3, and Class 4 locations have been subject to reporting requirements in part 191 and safety requirements in part 192. Type A lines, which operate at higher pressure, are required to comply with most safety requirements applicable to transmission pipelines at part 192, while lower-pressure Type B lines are required to follow fewer requirements, which are listed in § 192.9(d).

When PHMSA last issued regulations addressing the safety of gas gathering lines in 2006,[16] it exempted gathering lines in Class 1 locations from reporting and safety requirements in parts 191 and 192. At the time, such pipelines were mostly small-diameter, low-pressure pipelines located in sparsely populated, traditional oil-producing regions and were thought to pose relatively low risks to the public. However, by the time that the 2006 final rule was adopted, innovative drilling technologies, new hydrocarbon discoveries, and increasing demand for natural gas were starting to transform the industry. Highly productive ''unconventional'' drilling techniques have proliferated, and modern production sites can be several times more productive than conventional wells. The characteristics of the gathering lines servicing current wells often have more in common with large interstate transmission systems than the diffuse network of small gathering lines that predominated when the current gas

[13] References in this final rule to ''gathering'' therefore refer, unless specified otherwise, to onshore gas gathering pipelines. Similar to Type A onshore gas gathering lines, offshore gas gathering lines are already covered by the requirements in part 192 applicable to transmission lines, with some exceptions listed in § 192.9(b).

[14] This final rule and amended regulatory text use the formulation ''Type C'' to identify the newly-regulated onshore gathering lines described in the NPRM as ''Type A, Area 2.'' However, in discussion of the NPRM and comments thereon, this final rule will use the formulation ''Type A, Area 2'' for the convenience of the reader.

[15] 58 FR 51375 (Oct. 4, 1993).

[16] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 FR 13289 (Mar. 15, 2006).

gathering regulatory framework was being developed prior to 2006. These changes are placing unprecedented demands and increasing safety risks on the Nation's pipeline system.

The final rule requires operators of all onshore gas gathering lines to prepare and submit annual reports with information about their gas gathering lines and to submit incident reports under part 191. The information is necessary to monitor the safety performance of gas gathering systems and inform the appropriate level of regulatory oversight. This final rule also adopts new safety requirements for larger-diameter (*i.e.,* with outer diameters of 8.625 inches or greater), higher-operating pressure gas gathering lines to mitigate risks to public safety and pipeline integrity. The need to implement risk-based protections and build an understanding of the safety of gas gathering systems is critical since ''unconventional'' production operations continue to expand, often into regions inexperienced with oil and gas development—posing new risks to humans and the environment.

Natural Gas Gathering Infrastructure Overview

The U.S. natural gas pipeline network is designed to transport natural gas to and from most locations in the country. Approximately two-thirds of the lower 48 States depend almost entirely on the interstate transmission pipeline system for their supplies of natural gas.[17] In 49 CFR part 192, pipelines are classified into three broad groups, based on their function and characteristics: Gathering, transmission, and distribution systems. Onshore gathering lines, the sole subject of this final rule, typically transport gas from production fields to gas transmission pipelines or centralized processing and storage facilities. From there, gas is typically transported to large industrial users such as gas-fired power stations or local distribution companies via transmission pipelines. Finally, distribution companies deliver gas to homes and businesses, and other end-users. Together, these systems form an interconnected network that transports natural gas from the production field to its end users. PHMSA estimates that there are over 400,000 miles of onshore gas gathering lines throughout the U.S., the vast majority of which are in Class 1 locations.[18]

Regulatory History

The Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90–481) vested the Secretary with statutory authority to issue regulations to ensure the safe transportation of natural gas by pipeline but excluded the regulation of gas gathering lines in rural areas, which were defined in section 2(3) of the 1968 Act as those locations outside the limits of any incorporated or unincorporated city, town, or village, or other designated residential or commercial area. Later, Congress modified the definition of ''transporting gas'' to provide Secretary the authority to designate non-rural areas in order to make pipelines in those non-rural areas subject to PHMSA's jurisdiction (49 U.S.C. 60101(a)(21)(B)).

PHMSA,[19] through delegation by the Secretary,[20] and its State partners enforce requirements for regulated [21] gas gathering systems in the Federal Pipeline Safety Regulations that are authorized under 49 U.S.C. 60101 *et seq.* DOT issued interim minimum Federal safety standard regulations for gas pipeline facilities and the transportation of natural and other gas by pipeline on November 13, 1968,[22] and subsequently codified broad-based gas pipeline regulations in 49 CFR part 192 on August 19, 1970.[23] The 1970 final rule defined a ''gathering line'' as ''a pipeline that transports gas from a current production facility to a transmission line or main,'' and subjected all gathering lines located in non-rural areas (*e.g.,* within the limits of any incorporated or unincorporated city, town, or village, or other designated residential or commercial area) to all requirements applicable to transmission pipelines (§§ 192.1 and 192.9).

This historical approach to defining PHMSA's jurisdiction, however, has left several key gaps which made it difficult to determine where a gathering line started and ended. One was that it failed to define ''current production facility,'' and therefore the point where a non-jurisdictional production facility became a gathering line was not clear.[24] Additionally, there was no clear definition of where a gathering line ended, and a transmission pipeline or distribution main line began. The DOT has attempted to clarify these gaps several times. In 1974, DOT proposed to revise the definition of a gas ''gathering line'' to address this uncertainty as to the beginning and end points of gas gathering.[25] However, the proposal was later withdrawn.[26]

In 1991, DOT again proposed to revise the definition of a gathering line following a NAPSR survey of its members noting ongoing disagreements about the classification of certain segments of gas pipelines.[27] However, in response to comments on the proposed rule and the issuance of the Pipeline Safety Act of 1992 (Pub. L. 102–508), PHMSA delayed final action on that proposal to consider additional information and the statutory changes. As described earlier, PHMSA was previously restricted from issuing regulations for rural gathering lines. Section 109 of The Pipeline Safety Act of 1992 expanded DOT's authority by authorizing the Secretary to define the term ''regulated gathering line,'' and issue safety regulations for the transportation of gas through those pipelines despite their location in rural areas (49 U.S.C. 60101(b)). The Pipeline Safety Act of 1992 also directed DOT to consider functional and operational characteristics in defining gathering lines (49 U.S.C. 60101(b)(1)(B)(i)). For the definition of the term ''regulated gathering line,'' Congress further directed DOT to consider such factors as location, length of line from the well site, operating pressure, throughput, and gas composition in deciding which gathering lines are functionally gathering yet warrant regulation as regulated gathering lines (49 U.S.C. 60101(b)(2)(A)). This authority also expressly allowed DOT to depart from the concepts used to define gathering for the purposes of determining the scope of the Federal Energy Regulatory

[17] U.S. Department of Energy (DOE), ''Appendix B: Natural Gas—Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure'' p. NG–28 (Apr. 2015).

[18] API estimated there were 240,000 miles of unregulated gathering lines in comments submitted October 23, 2012, available in the docket. In order to project an estimate of gathering lines in service today, PHMSA adjusted this estimate based on average rate of increase in reported mileage of regulated gathering lines from operators' annual reports since 2012. *See* the RIA, available in the docket, for additional information on estimates of gathering miles affected by the rule.

[19] PHMSA's predecessor agencies include the Research and Special Programs Administration (RSPA), the Materials Transportation Bureau (MTB), and the Office of Pipeline Safety (OPS). For simplicity, all are referred to as DOT in this section.

[20] 49 CFR 1.97.

[21] Typically, onshore pipelines involved in the ''transportation of gas,'' *see* 49 CFR 192.1 and 192.3 for detailed applicability.

[22] Interim Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline, 33 FR 16500.

[23] Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, 35 FR 13248.

[24] Transportation of Natural and Other Gas by Pipeline: Proposed Definition of Gathering Line, 39 FR 34569 (Sept. 26, 1974).

[25] Id.

[26] Transportation of Natural and Other Gas by Pipeline: Withdrawal of Proposed Definition of Gathering Line, 43 FR 42773 (Sept. 21, 1978).

[27] Gas Gathering Line Definition: Notice of Proposed Rulemaking, 56 FR 48505 (Sept. 25, 1991).

Commission's (FERC) authority under the Natural Gas Act (15 U.S.C. 717 *et seq.*) in order to define gas gathering lines based on functional, rather than rate-setting, considerations. In other words, whether the DOT classifies a pipeline as a transmission line, gathering line, or regulated gathering line has no impact on the pipeline's status with FERC and vice-versa.

In 1999, PHMSA renewed the effort to define gathering lines. To facilitate this project, PHMSA opened a website for public discussion on the question of how to define gas gathering lines and whether there was a need to subject rural gathering lines to Federal safety oversight.[28] The majority of the comments received focused on the work that was being done by API to classify gathering lines. That effort culminated in the publication of the first edition of API RP 80 in April 2000.

The purpose of API RP 80 is to define gas gathering lines in onshore areas based on the line's function. It distinguishes a gathering function from a ''production operation'' that is not engaged in transportation (see section 2.3 of API RP 80) and defines a number of points that determine the potential endpoint of the gathering function (see section 2.2(a)(1)(A) through (a)(1)(D) of API RP 80), such as the inlet to the furthermost downstream gas processing plant or the furthermost downstream point where gas produced in the same production field or separate production fields is commingled. API RP 80 defines a gathering line as ''a pipeline, or a connected series of pipelines, used to transport gas from the furthermost downstream point in a production operation to the furthermost downstream of one of the defined endpoints of gathering.'' The document also includes supplementary definitions, discussion, and diagrams to provide additional guidance on how operators may apply these definitions to various types of gathering systems. Section 192.8 includes limitations on how aspects of API RP 80 must be applied.

Ever since API RP 80 was first issued, PHMSA has had concerns about ''incidental gathering.'' While section 2.2(a)(1)(A) through (a)(1)(D) describe points where the gathering function can end, paragraph (a)(1)(E) allows an operator to designate pipeline segments that are past the furthermost downstream of the other endpoint of gathering up to the connection to ''another pipeline'' (typically a transmission line) as a gathering line regardless of the actual function or operational characteristics of the pipeline itself. This is the ''incidental gathering'' concept discussed in API RP 80 section 2.2.1.2.6. By definition, these lines extend beyond the end of any gathering functions. When a major gas processing plant or a compressor used to raise the pressure for delivery into a transmission line is the endpoint, the incidental gathering line segment can be indistinguishable from a transmission line in terms of its function, diameter, pressure, and gas composition; yet is treated as a gathering line rather than a transmission line under part 192. Additionally, there are no limits on how far an incidental gathering line may extend under the API RP 80 definition. The API RP 80 concept of ''incidental gathering'' undermines the functional definition of ''gathering'' that API RP 80 was intended to establish. In fact, API RP 80 creates a regulatory gap for pipeline segments that bear the least functional and operational resemblance to gathering lines.

In 2003, DOT held public meetings in Austin, Texas, and Anchorage, Alaska, to determine the best way to define the terms ''gas gathering line'' and ''regulated gathering line'' and what, if any, safety rules would be needed for rural regulated gathering lines.[29] At the meetings, DOT proffered a ''sliding corridor'' concept as a possible basis for defining which gathering lines should be designated as regulated gathering lines. This concept was similar to the ''sliding mile'' used for class location determinations, except that the corridor would be 1,000 feet long rather than one mile, and the width would vary depending on the stress level of the segment of pipe. Wherever the corridor contained five or more dwellings, the gathering line segment would be subject to a subset of Federal Pipeline Safety Regulations, the scope of which would increase as the stress level [30] of the segment increased.

After these two meetings, DOT published a document that stated that the definitions of production and gathering should ensure that Federal regulation of gathering lines does not overlap with State regulations on production, and should promote consistent application by regulators and operators.[31] The document invited comments on an appropriate approach for identifying rural gas gathering lines that warranted regulation. After the 2003 public meetings, DOT met several times with State agency officials, industry representatives, and others to obtain different views on the risks posed by gas gathering lines and the need for Federal regulation over the same.

In 2006, DOT published a final rule that established the current Federal Pipeline Safety Regulations for gas gathering lines in §§ 192.8 and 192.9.[32] The final rule incorporated by reference API RP 80, which defines ''onshore gas gathering pipelines.'' The 2006 final rule also replaced the previous ''non-rural'' criteria for designating regulated gathering lines in § 192.9 with a risk-based approach to regulating gas gathering lines in Class 2, 3, and 4 locations. In the 2006 final rule, PHMSA chose not to extend any reporting or safety requirements to gas gathering lines in Class 1 locations. At the time, PHMSA noted that such pipelines were typically small-diameter, low-pressure lines posing relatively low risks to the public. The Federal requirements for gas gathering lines have remained in place, mostly unchanged, since 2006.

Supply Changes

Between 2005 and 2019, marketed production of natural gas increased from 18.9 trillion cubic feet (Tcf) per year to 36.5 Tcf per year.[33] While gross gas production from conventional wells has fallen by 53 percent from 16.2 Tcf per year to 7.6 Tcf per year between 2005 and 2019,[34] overall production has grown due to increased unconventional shale gas production. EIA began reporting shale gas well withdrawals in 2007. In 2007, unconventional shale gas accounted for about 8 percent of the total natural gas production in the U.S. Since then, shale gas production has increased from 1.9 trillion cubic feet per year to 27.8 trillion cubic feet per year in 2019 [35] and now accounts for

[28] Request for Comments: Gas Gathering Line Definition, 64 FR 12147 (Mar. 11, 1999).

[29] *See* 68 FR 62555 (Nov. 5, 2003) (Austin, TX, meeting) and 68 FR 67129 (Dec. 1, 2003) (Anchorage, AK, meeting). Transcripts for the meeting are available for download at *regulations.gov* under Docket No. PHMSA–RSPA–1998–4868.

[30] Expressed as the circumferential fore on a pipe (hoop stress) produced by the MAOP as a percent of the specified minimum yield strength (SMYS). SMYS is defined in § 192.3 and refers to the minimum force required to deform permanently the material as specified in the applicable design codes.

[31] Gas and Hazardous Liquid Gathering Lines: Clarification of Rulemaking Intentions and Extension of Time for Comments, 69 FR 5305 (Feb. 4, 2004).

[32] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 FR 13289 (Mar. 15, 2006).

[33] EIA, ''U.S. Natural Gas Marketed Production,'' *https://www.eia.gov/dnav/ng/hist/n9050us2a.htm* (accessed Nov. 9, 2020).

[34] EIA, ''U.S. Natural Gas Gross Withdrawals from Gas Wells,'' *https://www.eia.gov/dnav/ng/hist/n9011us2a.htm* (accessed Nov. 9, 2020).

[35] EIA, ''U.S. Natural Gas Gross Withdrawals from Shale Gas,'' *https://www.eia.gov/dnav/ng/hist/ngm_epg0_fgs_nus_mmcfa.htm* (accessed Nov. 9, 2020).

approximately 68 percent of overall gross gas production.

This increase in unconventional gas extraction has shifted production from traditional gas producing regions such as Texas, Louisiana, Oklahoma, and the Gulf of Mexico to other areas, such as Pennsylvania and Ohio. For instance, in 2001, 5,066,015 million cubic feet (MMcf) of natural gas was withdrawn from the Gulf of Mexico, which was approximately 21 percent of the Nation's natural gas gross production. By 2019, withdrawals decreased to 1,033,922 MMcf. During that same period, Pennsylvania's share of production grew from 130,853 MMcf to 6,896,792 MMcf.[36] The Department of Energy projects that more than half of increases in shale gas production through 2050 will occur in the Appalachian Basin (*e.g.,* the Marcellus and Utica Basins), which will continue to fuel growth in natural gas production from the 2020 levels of 33.9 t (Tcf) per year to 43.0 Tcf per year in 2050.[37]

Demand Changes

Increased production of natural gas in the United States has depressed average prices and volatility.[38] In 2004, the growth outlook for natural gas production was weak; the EIA forecasted that dry gas production would increase by only 1.0 percent annually [39] and that production in the lower 48 would be 21.3 Tcf per year by 2025, or up to 25.1 Tcf per year in the rapid technology scenario.[40] At the time, monthly average spot prices at Henry Hub [41] were high, based on historic comparison of prices, fluctuating between $4 per million British thermal units (Btu) and $7 per million Btu. Prices rose above $11 per million Btu for several months in both 2005 and 2008.[42] Since then, after production shifted to onshore unconventional shale resources and price volatility decreased since 2009, natural gas has frequently traded between $2 and $4 per million Btu, and the spot price has not been above $6 per million Btu for any full month.[43]

This fall in natural gas prices and volatility was accompanied by significant demand growth and changes to the geography of gas demand. Low fuel costs, improved gas turbine technology, operational advantages, and greenhouse gas concerns have driven a steady growth in gas-fired electricity generation. According to the Department of Energy, natural gas surpassed coal as the fuel with the highest share of net electricity generation in 2016.[44] Natural gas exports have also increased. In 2019, the U.S. exported 4.7 Tcf of gas, over six times the amount that was exported in 2006.[45] Virtually all the gas produced and consumed in the U.S. is transported by gas gathering and transmission pipelines to distribution pipelines or end-users.

Consequences for Gas Gathering

Modern production techniques, higher production volumes, and the geography of new gas discoveries have had consequences for gas gathering systems that PHMSA did not contemplate in 2006. Individual unconventional wells can be several times more productive than conventional facilities, and multiple wells can be drilled from a single wellpad, resulting in a large increase in the volume of gas that can flow from production and gathering lines serving a single site. In addition, these productivity gains have led to a surge in production overall, which expands the demands placed on the overall gas gathering pipeline network. Modern gas gathering lines often bear a closer resemblance to large interstate transmission lines than the diffuse network of small, low-pressure lines that previously characterized gathering lines. An incident on such pipelines can have serious consequences, even in a Class 1 location.

Although PHMSA has not collected annual report information on the mileage or diameter of gas gathering lines in Class 1 locations, various stakeholders have reported significant growth in large-diameter, high-pressure gas gathering lines operating outside the scope of the Federal Pipeline Safety Regulations. NAPSR noted in the preamble to its Resolution 2010–2 AC–2 that ''it is not uncommon to find rural gas gathering pipelines up to 30 inches in diameter and operating at a MAOP of 1480 psi [pounds per square inch, or approximately 1495 pounds per square inch gauge (psig)]'' in modern gas gathering systems,[46] which resembles the operational characteristics of major interstate transmission pipelines that are subject to part 191 and 192 regardless of where they are located. Similarly, the GAO noted that 24-inch diameter unregulated gathering lines were located and constructed in close proximity to homes in Pennsylvania, and 30 to 36-inch diameter unregulated gas gathering lines were planned for construction in the Eagle Ford shale formation in Texas.[47] In comments to the NPRM, the Pennsylvania Public Utility Commission noted that producers in the State are constructing gas gathering lines as large as 36 inches in diameter with operating pressures up to 1480 psig.

The energy that can be released in a pipeline explosion or fire is proportional to a pipeline's throughput capacity. The potential impact radius formula in § 192.903, which calculates the radius of a circle within which the potential failure of a pipeline could have a significant impact on people or property, increases proportionally with pressure and exponentially with the diameter of the pipeline. An incident on any large-diameter, high-pressure natural gas pipeline can have potentially catastrophic consequences, regardless of whether it is defined as a transmission or gathering line, and even in sparsely populated Class 1 locations. For example, one of the deadliest gas transmission pipeline incidents in U.S. history occurred in a Class 1 location when a 30-inch transmission line operated at 675 psig ruptured near Carlsbad, New Mexico, on August 19, 2000.[48] In that incident, internal

[36] EIA, ''Gulf of Mexico—Offshore Natural Gas Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/na1060_r3fmtf_2a.htm* (accessed Nov. 9, 2020); EIA, ''Pennsylvania Natural Gas Gross Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/n9010pa2a.htm* (accessed Nov. 9, 2020).

[37] EIA, ''Annual Energy Outlook 2021'' (Feb. 3, 2021), *https://www.eia.gov/outlooks/aeo/production/sub-topic-01.php.*

[38] DOE, ''Appendix B: Natural Gas—Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,'' at NG–11 (Apr. 2015), *https://www.energy.gov/sites/prod/files/2015/04/f22/QER-ALL%20FINAL_0.pdf.*

[39] EIA, ''Annual Energy Outlook 2004 With Projections to 2025,'' at 133 (Jan. 2004), *https://www.eia.gov/outlooks/archive/aeo04/pdf/0383(2004).pdf.*

[40] *Id.* at 90.

[41] Henry Hub is a Louisiana natural gas distribution hub where conventional Gulf of Mexico natural gas can be directed to gas transmission lines running to different parts of the country. Natural gas bought and sold at the Henry Hub serves as the National benchmark for U.S. natural gas prices. *Id.* at NG–29, NG–30.

[42] EIA, ''Natural Gas Spot and Futures Prices,'' *http://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm,* (accessed Nov. 9, 2020).

[43] *Id.*

[44] EIA, ''Electric Power Annual 2019'' Table 3.1.A (Oct. 2020), *https://www.eia.gov/electricity/annual/* (accessed Nov. 9, 2020).

[45] EIA, ''U.S. Natural Gas Exports,'' *https://www.eia.gov/dnav/ng/hist/n9130us2a.htm* (accessed November 9, 2020).

[46] NAPSR, Resolution 2010–2AC–2 (Sept. 30, 2010), *http://nebula.wsimg.com/215b293abe58ff21d6d2ad867ae864a3?AccessKeyId=8C483A6DA79FB79FC7FA&disposition=0&alloworigin=1.*

[47] GAO, No. 14–667 at 24.

[48] National Transportation Safety Board (NTSB), NTSB/PAR–03/01, ''Pipeline Incident Report: Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico'' (Feb. 2003), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR0301.pdf.*

corrosion led to an explosion that killed 12 individuals who had been camping 675 feet from the rupture site. Following this incident, PHMSA added § 192.476 requiring operators to incorporate measures to mitigate internal corrosion threats in the design and construction of new transmission lines—however, that requirement does not affect gathering lines that may have a similar risk profile. In another incident on December 11, 2012, a 20-inch transmission line with a MAOP of 1000 psig ruptured in Sissonville, West Virginia, due to corrosion caused when the protective pipe coating was damaged by rocky backfill during installation. While there were no serious injuries in that incident, three houses and several hundred feet of road surface were destroyed, and Interstate 77 was shut down for 19 hours.[49] The fire melted a portion of the interstate highway, prompting one local official to describe the highway as looking ''like lava, just boiling.'' [50]

Although PHMSA has not historically collected incident reports for gas gathering lines in Class 1 locations, such gathering lines are subject to incidents of similar magnitude and consequence as gas transmission pipelines with comparable physical and operating characteristics. For example, on November 14, 2008, a 20-inch gas gathering line exploded in Grady County, Oklahoma, which injured two people, destroyed three homes, and shut down a nearby highway.[51] On June 8, 2010, a bulldozer struck a 14-inch gas gathering line in Darrouzett, Texas, causing an explosion that killed two workers and injured three others, including one worker who was critically injured and required medical evacuation by helicopter.[52] On June 29, 2010, three men working on a 24-inch gas gathering line in Grady County, Oklahoma, were injured when it exploded; one worker was airlifted to a nearby hospital with burns covering half of his body.[53] On August 1, 2018, a six-inch gas gathering line failed in Midland, Texas, which caused a nearby 12-inch transmission line to also explode, killing one worker and injuring seven others.[54] A few days later, on August 9, 2018, corrosion on a 10-inch gas gathering line resulted in another explosion in Midland, killing a three-year-old girl and badly burning three others. Fatal incidents on smaller lines such as the first Midland, Texas, incident described above and an explosion caused by an improperly abandoned 2-inch production line connected to a gas well in Firestone, Colorado,[55] underscore the need to collect information on the risks posed by smaller diameter lines. Even non-fatal incidents can result in significant damage to infrastructure and property, lead to evacuations, disrupt gas service, or otherwise harm the public, property, or the environment.

These hazards may be further exacerbated by the changing geography of U.S. gas production, which was noted by the GAO in their March 2012 report, ''Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety.'' Incidents involving new gas production fields may overwhelm the capabilities of local first responders in rural areas who may lack experience and the resources to respond adequately to serious incidents associated with intensive gas production and processing operations, including high-pressure pipelines.

Regulatory Gaps

PHMSA estimates that there are over 400,000 miles of unregulated onshore gathering lines. For comparison, operators reported 320,000 miles of gas transmission lines in 2019. As demonstrated above, even though some gathering lines share the same physical, functional, and operational characteristics and potential adverse consequences from an incident as transmission lines, they are exempt from reporting requirements in part 191 and minimum safety standards in part 192.

The final rule closes this gap by requiring all gas gathering facilities to submit incident reports and annual reports under part 191. In addition, the final rule adopts minimum safety standards for larger gas gathering lines that operate at higher pressures to help to ensure that operators address the critical risks that these previously unregulated facilities pose to pipeline integrity and public safety such as corrosion, excavation damage, and inadequate emergency response planning.

B. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM, soliciting public comments regarding the revision of the Pipeline Safety Regulations applicable to the safety of both gas gathering and gas transmission pipelines.[56] PHMSA requested comments regarding 15 topic areas covering gathering and transmission lines.

The specific issues related to gas gathering included whether regulatory exemptions for filing incident, annual, and safety-related condition reports should be repealed. In addition, PHMSA requested comment on a proposal to repeal the incorporation by reference of API RP 80 into the Pipeline Safety Regulations and replace it with a new definition of gathering lines in part 192 for determining the beginning and end points of gas gathering lines. Adoption of a new definition would address defining endpoints for non-jurisdictional gas production operations and setting limits for the ''incidental gathering'' concept in API RP 80. PHMSA also requested comment on expanding the definition of the term ''regulated onshore gas gathering pipelines'' to include a new category of high-pressure, large diameter gathering lines in Class 1 Locations.

PHMSA received 103 comments to the ANPRM. Based on these comments, PHMSA developed proposals for some of those topics in an NPRM published on April 8, 2016 (NPRM), which is the basis for this final rule.

C. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

Section 21 of the 2011 Pipeline Safety Act mandated that DOT review its existing regulations for gas gathering lines and report to Congress on the sufficiency of existing Federal and State laws to ensure the safety of gas

[49] NTSB, NTSB/PAR–14/01, ''Accident Report: Columbia Gas Transmission Corporation Pipeline Rupture Sissonville, West Virginia'' (Feb. 2014), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1401.pdf.*

[50] Brinks, Travis, ''Remembering the Sissonville Pipeline Explosion.'' *WV Metro News.* Dec. 11, 2023, *https://wvmetronews.com/2013/12/11/remembering-the-sissonville-pipeline-explosion/* (accessed June 15, 2021).

[51] Griswold, Jennifer and Sargent, Brian. ''Natural Gas Pipeline Explosion Destroys Homes Near Alex.'' *The Oklahoman,* Nov. 14, 2008, *www.oklahoman.com/article/3321932/natural-gas-pipeline-explosion-destroys-homes-near-alex* (accessed Feb. 12, 2021).

[52] The Associated Press. ''Two Killed in Texas Panhandle Gas Line Explosion.'' *Arkansas Democrat Gazette,* June 8, 2010, *www.arkansasonline.com/news/2010/jun/08/2-killed-texas-panhandle-gas-line-explosion/* (accessed Feb. 12, 2021).

[53] Pittman, Jerry. ''Pipeline Explosion West of Pocasset Injures Three, One Seriously.'' *The Oklahoman,* June 29, 2010, *www.oklahoman.com/article/3472182/pipeline-explosion-west-of-pocasset-injures-three-one-seriously,* (accessed Feb. 12, 2021).

[54] Lee, Mike, and Soraghan, Mike. ''Deadly Pipelines, No Rules.'' *E&E News,* Mar. 4, 2019, *www.eenews.net/special_reports/EEnews_highlights/stories/1060123021,* (accessed Feb. 12, 2021).

[55] NTSB, NTSB/PAB–19/02, ''Pipeline Accident Brief Natural Gas Explosion at Family Residence Firestone, Colorado'' (Oct. 2019), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAB1902.pdf.*

[56] Pipeline Safety: Safety of Gas Transmission Pipelines, 76 FR 53086.

gathering lines; the economic impacts, the technical practicability, and challenges of applying existing Federal regulations to unregulated gathering lines; and the need to modify or revoke existing exemptions from Federal regulation for gathering lines, subject to a risk-based assessment. PHMSA sent the required report to Congress on May 8, 2015.[57] The report identified issues with the difficulty of designated gathering lines in complex systems due to missing, ambiguous, or circular definitions of terms used to determine the start and end points of gathering lines, and used to describe state-level regulation of gathering lines. The report also observed that, with few exceptions, State regulators had not imposed design, construction, operation, and maintenance requirements for gathering lines beyond existing Federal requirements for Type A and Type B regulated gathering lines. The report also notes that most of the States which had established requirements for gathering lines other than Federally regulated Type A and Type B gathering lines had not adopted prescriptive safety standards or performance standards with well-defined authorized acceptance criteria. The report informs this rulemaking.

D. Government Accountability Office (GAO) Recommendations

The GAO issued GAO–12–388 in March 2012, which recommended PHMSA collect data on Federally unregulated hazardous liquid and gas gathering lines comparable to the data collected from operators of regulated gathering lines. The GAO suggested that the purpose of such data collection would be to assess the safety risks posed by unregulated gathering lines. GAO also noted that States and operators could use this information to share effective safety practices and lessons learned. In August 2014, the GAO issued a report, GAO–14–667, which further recommended that PHMSA initiate a rulemaking to address gathering line safety that would focus on the risks presented by larger-diameter, higher-pressure gathering lines, including a requirement that such pipelines meet emergency planning requirements.[58]

E. Notice of Proposed Rulemaking

On April 8, 2016, PHMSA published the NPRM, which proposed new pipeline safety requirements and revisions of existing requirements in 16 major topic areas.

To manage the breadth of the topics raised in the NPRM, PHMSA separated the topics into three final rules. The first of final rule addressed the gas transmission mandates in the 2011 Pipeline Safety Act; a final rule was published in this rulemaking on October 1, 2019.[59] That final rule addresses comments received concerning the scope of the proposed gas transmission requirements for existing Type A and Type B regulated gathering lines. The second final rule is this one, which addresses only the portions of the NPRM affecting the safety of gas gathering lines, particularly reporting requirements for all gas gathering lines and additional requirements for Type C regulated gathering lines. The remaining gas transmission pipeline concerns are being considered in a third final rule (under Regulatory Identification Number 2137–AF39) that is under development.

With respect to the current rulemaking, the NPRM contained proposals to:

(1) Extend part 191 requirements for incident reports, annual reports, and safety-related condition reports to all gas gathering lines;

(2) repeal the incorporation by reference of API RP 80 and revise the regulatory definitions for determining if a pipeline is a gathering line;

(3) expand the scope of regulated gathering lines to include a new category of ''Type A, Area 2'' for gathering lines in Class 1 locations with a diameter of 8 inches or greater and operating at high pressure; and

(4) require newly regulated Type A, Area 2 gathering lines to comply with the existing requirements in § 192.9 for Type B gathering lines, plus an additional requirement for establishing emergency plans per § 192.615.

Pursuant to 49 U.S.C. 60115(c), PHMSA shared the proposed standards on gathering lines with the Gas Pipeline Advisory Committee (GPAC) after initially considering the comments to the NPRM.[60] The GPAC met on June 25–26, 2019, to consider the proposed standards regarding gathering lines. Subsequently, PHMSA posted the meeting slides that were used for the GPAC votes as well as the transcript, which constitute the statutorily required report of the GPAC's recommendations, including minority views.[61]

A summary of the four pertinent NPRM proposals, comments received on these proposals, the GPAC recommendations, and PHMSA's responses to the comments are provided in section III below.

F. Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020

The 2020 PIPES Act was enacted on December 28, 2020. Section 112(a) directed PHMSA to issue a final rule in this rulemaking by the March 27, 2021.

III. Summary of the NPRM Comments, and GPAC Recommendations, and PHMSA Responses

The comment period for the NPRM ended on July 7, 2016, after being extended for one month. PHMSA received over 400 comments from groups representing the regulated pipeline industry; groups representing public interests, including environmental organizations; State utility commissions and regulators; members of Congress; individual pipeline operators; and private citizens. PHMSA received several comments after the July 7, 2016 deadline. Consistent with §§ 5.13(i)(5) and 190.323, PHMSA considered those late-filed comments considering commenters' interest in the rulemaking and the absence of additional expense or delay resulting from their consideration.

Pursuant to 49 U.S.C. 60115(e), the GPAC met on June 25 and 26, 2019 to consider the topics related to the safety of gas gathering lines in the NPRM. The GPAC came to consensus decisions and voted on recommended changes to the NPRM elements that would make those regulatory amendments more technically feasible, reasonable, cost-effective, and practicable. These recommendations are documented in

[57] PHMSA, Report to Congress: Natural Gas and Hazardous Liquid Gathering Lines (May 2015), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/report_to_congress_on_gathering_lines_0.pdf.*

[58] On September 29, 2015, GAO prepared a statement, GAO–15–843T (''Department of Transportation Needs to Complete Regulatory, Data, and Guidance Efforts'') reiterating the need for PHMSA to complete its regulatory efforts based on GAO's previous recommendations.

[59] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 FR 52180.

[60] The Technical Pipeline Safety Standards Committee, or GPAC, is an advisory committee, created pursuant to 49 U.S.C. 60115, that advises PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas pipelines. The GPAC was established under the Federal Advisory Committee Act (Pub. L. 92–463) and section 60115 of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*). The GPAC consists of 15 members, with membership divided among Federal and State agencies, the regulated industry, and the public. The GPAC considers the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

[61] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143.*

the transcript of the meeting and summarized in the vote slides.[62]

A. Reporting Requirements—§§ 191.1, 191.15, 191.17, 191.23, and 191.29

1. Summary of PHMSA's Proposal

Existing § 191.1(b)(4)(ii) exempts all onshore gas gathering lines other than regulated gathering lines (as specified in accordance with § 192.8) from all reporting requirements of part 191.

The NPRM proposed to repeal the exemption in § 191.1(b)(4) for gas gathering lines that are not regulated under § 192.8. However, the NPRM would continue to exempt previously unregulated gathering lines from Operator Identification Number (OPID) validation requirements in § 191.22(b) and National Pipeline Mapping System (NPMS) requirements in § 191.29. Therefore, all gas gathering lines, including previously unregulated gathering lines, would be required to comply with annual and incident reporting requirements in §§ 191.15, 191.17, and 191.25. This proposal was intended to provide new information on the extent, configuration, and safety performance of previously unregulated gas gathering lines.

The proposed rule would have required submission of OPID requests, incident reports, and safety-related condition requests beginning on the effective date of a final rule. Annual reports would have been due on March 15 of the calendar year after the effective date of a final rule.

2. Summary of Public Comments

Several citizen and public safety, and environmental groups, including the Pipeline Safety Trust (PST), the Wisconsin Safe Energy Alliance, NAPSR, the Coalition to Reroute Nexus, Earthworks, and the Environmental Defense Fund (EDF), supported the proposed provisions to remove the exemption for filing reports by operators of unregulated gas gathering lines. NAPSR agreed that extending reporting requirements to ''unregulated'' gathering lines would help determine if current operation and maintenance practices pose a risk to public safety and if additional requirements are required but suggested that PHMSA consider limiting certain requirements that could pose an unnecessary burden, such as detailed leak reporting information in part M of the gas transmission and gas gathering annual report form (DOT Form PHMSA F 7100.2–1). Some public commenters emphasized that available data on unregulated facilities could be inaccurate or outdated, particularly in areas where gas development has grown rapidly. Some of these groups also encouraged PHMSA to require gas gathering operators to submit geospatial pipeline location data for the NPMS, citing the usefulness of NPMS data for determining the need for future regulation.

Trade associations and pipeline industry entities provided a variety of responses to the proposed reporting requirements, ranging from full support, including for NPMS reporting, to total opposition to all proposed reporting requirements. The Independent Petroleum Association of America (IPAA) and other commenters representing oil and gas producers opposed changes to the scope of part 191 and commented that PHMSA has no statutory authority to apply reporting requirements to production lines and gathering lines that are not regulated gathering lines determined pursuant to § 192.8.

Several trade association and pipeline industry commenters including API, GPA Midstream (formerly the Gas Processors Association) and IPAA, expressed concern that the proposed reporting requirements could have significant cost impacts for operators that were not commensurate with the risk posed by the majority of those lines. Industry commenters also commented that it is not feasible to collect the information necessary to complete the proposed annual report by the reporting deadline of March 15 as required by § 191.17 on top of the efforts necessary to identify Type A, Area 2 (or Type C) regulated gas gathering lines within six months of the effective date the rule (see section III.C. below).

Industry commenters were especially concerned about reporting requirements for pipeline attributes that were related to requirements that did not apply to unregulated gas gathering lines. For example, GPA, API, and other industry commenters argued that the reporting of safety-related conditions (§ 191.23), including MAOP exceedances, would require information on MAOP, corrosion monitoring, and SMYS that were not otherwise required for previously unregulated gathering lines. The current forms for submitting gas transmission and gathering incident reports (F 7100.2) and annual reports (F 7100.2–1) also refer to regulations or records not required for unregulated gas gathering operators. These commenters recommended that PHMSA create separate incident and annual report forms for gathering lines that would collect information relevant to gas gathering lines that are not subject to part 192 and eliminate the proposed requirement to report safety-related conditions.

GPA Midstream commented that they supported PHMSA's goal of collecting necessary information on gas gathering lines, but that an abbreviated annual report form was necessary to avoid unnecessary costs. GPA Midstream further commented that unregulated gas gathering lines should be excepted from the OPID validation and change notification requirements in § 191.22(b) and (c).

3. GPAC Recommendations

Following discussion in the June 2019 meetings, the GPAC voted 12–0 that the proposed requirement that operators of newly regulated gas gathering lines file annual and incident reports pursuant to part 191 was technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Add specificity to location (*e.g.,* latitude and longitude coordinates) and cause information to the incident report form;
- Make sure all appropriate current annual report data elements are incorporated in the annual report form for currently unregulated gathering lines, including decade of installation;
- Address the possibility of unknown data;
- Implement a phase-in period of at least 24 months for unregulated gathering annual reports; and
- Consider additional comments from members submitted to the meeting docket (PHMSA–2016–0136), specifically, position papers from API/GPA Midstream and PST submitted in response to the GPAC meeting notice, and comments submitted after the GPAC meeting by each of GPA Midstream and the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada, AFL–CIO.

The GPAC agreed that the proposed reporting requirements were needed to support future oversight, but recommended changes on the details of implementation. PHMSA explained that it intended to create a new annual report form for gas gathering lines that are not subject to safety requirements in part 192 (reporting regulated gathering lines) separate from the existing DOT Form PHMSA 7100.2–1 required for operators of gas transmission and regulated gas gathering lines. This form would exclude information that is not relevant or applicable to operators of pipeline systems that are not required to comply with part 192.

[62] *See https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143.*

The GPAC recommended extending the compliance deadline for annual reports to 24 months after publication in the **Federal Register** to grant additional time for operators to identify newly regulated gathering lines and collect the necessary information. However, the GPAC agreed that incident reports should begin to be filed on the effective date of the rule since the data required to submit an incident report should be readily obtainable when an incident occurs.

4. PHMSA Response

PHMSA disagrees with comments that it lacks the statutory authority to require reports from operators of gathering lines other than currently regulated gathering lines as determined under § 192.8. Section 60117(b) of Federal Pipeline Safety Law specifically authorizes the Secretary to ''require owners and operators of gathering lines to provide the Secretary information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines.'' Congress made no distinction between ''gathering lines'' and ''regulated gathering lines'' for reporting purposes. This information-gathering process is precisely what the NPRM proposed—to gather information on all gathering lines that would enable PHMSA to make informed judgments about the need for, and scope, of potential regulation. Congress intended that the Secretary have the authority to request information from operators of unregulated gathering lines in order to help determine ''what additional gathering lines should be regulated.'' [63] PHMSA seeks to obtain information regarding current risks to people, property, and the environment due to unregulated rural gathering lines to determine whether rural gathering lines are presenting unacceptable risk that would warrant additional regulations. The information contained in annual and incident reports submitted by operators under part 191 would reasonably help achieve this objective.

In addition to the plain meaning of section 60117, Congress has articulated its intent for DOT to obtain information about the risks of rural gathering lines. In 1992, when Congress granted DOT authority to define gathering lines and regulated gathering lines for purposes of safety regulations, it recognized that some rural gathering lines might present unacceptable risks and authorized DOT to regulate lines whose risk warranted regulation. In its report on H.R. 1489, a bill leading to the Pipeline Safety Act of 1992, the House Committee on Energy and Commerce instructed DOT to ''find out whether any gathering lines present a risk to people or the environment, and if so, how large a risk and what measures should be taken to mitigate the risk.'' [64] The Committee reasoned that ''DOT had been attempting to define gathering lines for years. Anecdotal evidence indicates that there may be pipelines that are called gathering lines but that may really be transmission lines, and that there may be gathering lines that because of size or other physical characteristics should be regulated.'' [65] Although Congress did not require DOT to regulate gathering lines, it expected DOT to obtain the necessary information to determine whether risks exist to warrant regulation, as further evidenced by the House report: ''DOT is given a great deal of discretion to implement this section based on the information it receives as it proceeds. If DOT finds that none of these lines poses a hazard to people, property, or the environment, none of them will be regulated.'' [66]

The final rule fulfills the Congressional mandate by requiring operators of all onshore gas gathering lines to file incident and annual reports under part 191. This includes pipelines that are not currently designated as Type A or Type B regulated gathering lines nor newly designated as Type C gathering lines as a result of the final rule. For clarity, this final rule designates these reporting-regulated lines as ''Type R'' gathering lines that are subject to reporting under part 191 but are not designated as regulated gathering lines in part 192. These requirements are necessary to evaluate the safety risks on gas gathering systems and determine what, if any, additional measures may be warranted to reduce those risks. As demonstrated above, it is no longer reasonable to assume rural gas gathering lines pose uniformly low risk. Information on the changing functional and operational characteristics of gas gathering lines and their safety performance is necessary for PHMSA to better understand the consequences of these changes and to set requirements for gathering lines in the future. Extension of incident and annual reporting to these additional gas gathering lines will provide PHMSA information needed for identifying—and promulgating regulatory requirements or pursuing enforcement activity—design, manufacture, installation, and operational/maintenance issues common to particular pipeline characteristics or operators.

Congress also understood that the community around gathering lines can change and authorized DOT to consider these changes when regulating gathering lines. In its report that accompanied Senate Bill 1166, the bill that became the Natural Gas Pipeline Safety Act of 1968, the Committee on Interstate and Foreign Commerce recognized that the population in an area can change, and that the statute authorized DOT to define from time to time what is a non-rural area.[67] The Committee emphasized that a ''populated area'' means not only an area with a large number of people but also areas where pipeline rights-of-way are near houses, schools, and places of employment.[68]

However, PHMSA recognizes that some reporting requirements applicable to gas transmission and regulated gathering lines may not be necessary for gas gathering lines that are not currently subject to part 192. In particular, PHMSA is not requiring operators who are not required to establish an MAOP under part 192 to comply with requirements to report MAOP exceedances and other safety-related condition reports. In addition, in consideration of the comments, PHMSA is withdrawing the proposed requirement for gas gathering line operators that are not subject to part 192 to file safety-related condition reports required by § 191.23. Similarly, the final rule exempts gas gathering lines that are not subject to part 192 from the OPID validation and construction notification requirements in § 191.22(b) and (c) because such pipelines are not subject to the construction requirements in part 192.

While all gathering lines are now required to submit incident and annual reports, PHMSA is ensuring that the required data is applicable and relevant to operators of Type R gathering lines that are not subject to part 192. In consideration of comments on the NPRM and in the GPAC recommendations, PHMSA has

[63] S. Rep. 104–334, section 12 (104th Cong., 2nd Sess. 1996).

[64] H.R. Report No. 102–247(1), at 2653 (102nd Cong., 1st Sess. (1991)).

[65] *Id.*

[66] *Id.* Additionally, 49 U.S.C. 60101(b)(2)(A) specifically requires the Secretary, when defining ''regulated gathering line,'' to consider factors as location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas to determine which lines are functionally gathering and should be regulated because of their physical characteristics. It reasonably follows, as evident in the Congressional record, that Congress intended that Secretary could obtain such information from operators in order to consider such factors.

[67] H.R. Rep. 90–1390, at 3234 (90th Cong., 2nd Sess. 1968).

[68] *See id.*

developed a new annual report form and a new incident report form for operators of gas gathering lines that are not subject to part 192 with more limited information that is appropriate for such facilities. For example, with regard to annual reports, PHMSA has developed an abbreviated annual report form incorporating information specifically relevant to gas gathering lines that are not currently regulated under part 192, including the decade of installation, if known. New forms and instructions are available in the public docket and will be made available on PHMSA's website at *https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions.*

The new annual report and incident report forms for Type R gathering lines address the GPAC's recommendations, including:

- Requiring incident location information that is equivalent to what is required for regulated gas gathering lines;
- Annual report fields appropriate for identifying and evaluating public safety and environmental risks that may be associated with unregulated gas gathering lines, including:
  - Miles by decade of installation,
  - Miles by pipeline diameter,
  - Miles by pipe material and corrosion protection status, and
  - Number of leaks repaired or scheduled for repair.
- On the Type R annual report form, allow reporting of an unknown decade of installation.
- On the Type R incident report form, allow reporting of an unknown date of installation and certain fields related to pipeline material properties and damage prevention investigations.

In the final rule, operators of previously unregulated gas gathering lines must begin submitting annual reports beginning with the first annual report cycle occurring after the endpoints of Type C or Type R gathering lines have been determined one year after the publication date of the final rule. As a result, operators of Type R and Type C gathering lines must submit a 2022 annual report no later than March 15, 2023. March 15 is the existing deadline for submitting annual reports for other gas pipeline facilities, consistent reporting deadlines reduces confusion and administrative burdens on PHMSA and operators with both Type R and regulated gas pipeline facilities. This compliance deadline represents a phase-in period well in excess of a year as measured from the publication date of the final rule.

This compliance deadline is approximately 6 months shorter than recommended by the GPAC. However, PHMSA believes that prompt submission of such reports is necessary for PHMSA's timely evaluation of whether additional regulatory efforts are needed to manage the safety and environmental risks associated with Types C and R gathering lines. PHMSA's limited information on these lines inhibits the robust understanding of their environmental and public safety risks needed to determine whether additional requirements are also warranted. The longer the delay in obtaining that information, the longer before PHMSA can diagnose and respond to a need for additional public safety and environmental protections from previously-unregulated gas gathering lines. PHMSA therefore does not believe an [18 month] compliance timeline would be overly burdensome on affected operators when evaluated against those potential safety benefits. The simplified form for Type R lines includes provisions for ''unknown'' fields to minimize burdens on gathering line operators to complete. While the Type C form is more extensive, such lines are also more likely to be more modern shale gas systems installed within the last 10–15 years. PHMSA expects the use of electronic recordkeeping and geospatial information systems is more widespread among such operators compared with traditional gathering systems and therefore expects that completing Type C annual reports will not be overly burdensome on affected entities. Finally, PHMSA notes that the compliance timeline is consistent with the approach taken in historical expansions of pipeline reporting requirements. For example, in the final rule titled, ''Pipeline Safety: Safety of Hazardous Liquid Pipelines,'' [69] PHMSA required affected operators to submit annual reports the first year after the effective date.

For similar reasons, the final rule does not include provisions for operators to request a delayed compliance deadline for the annual report requirement similar to those included in §§ 192.8 and 192.9. Additionally, most of the records necessary to prepare an annual report are also necessary in order to define the endpoints of regulated gas gathering. Operators should therefore begin collecting the necessary information immediately in order to ensure they are able to submit a complete annual report on or before the deadline in the final rule.

[69] 84 FR 52260 (Oct. 1, 2019).

B. Gathering Line Definitions—§§ 192.3 and 192.8

1. Summary of PHMSA's Proposal

PHMSA proposed to revise 49 CFR part 192 to clarify the definition of gathering lines in order to address confusion regarding how the endpoints of gathering and production are currently determined. The existing definition of gathering lines relies on language in API RP 80. In practice, however, operators and inspectors have had difficulty consistently applying the definitions that are used to define the start and endpoints of gathering in API RP 80 given the complexities in the configuration of gathering line systems in midstream operations. In addition, Federal and State enforcement of the current requirements has been hampered by the use of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system. Specifically, API RP 80 defines certain processes and equipment that may constitute a ''production operation'' but does not include defined endpoints of the production function in section 2.3 like it does for gathering in section 2.2.

This issue was raised in comments by NAPSR and others, who suggested simplifying the definition of a gas gathering line and setting clear, restrictive limits on where non-jurisdictional production operation ends and gas gathering begins. NAPSR commented in response to the ANPRM that State regulators had ''many difficulties in applying the definitions contained in API RP 80'' and recommended a simpler definition for the term gathering line. NAPSR recommended defining the end of production at the wellhead or first metering point downstream of the well. As described in the regulatory history section, PHMSA also had concerns with how the ''incidental gathering'' concept has been used to classify pipelines that perform gas transmission functions as gathering lines subject to less stringent requirements intended for small, low-pressure, traditional gathering lines.

In lieu of relying on API RP 80's definition of gathering line, the NPRM proposed new stand-alone definitions for ''onshore production facility/operation'', ''gas processing plant,'' ''gas treatment facility'', and ''gathering line (onshore)'' to determine the beginning and endpoints of each gathering line. The proposed definitions were found in § 192.3 of the NPRM and the application of those definitions was included in § 192.8. PHMSA proposed to define the end of onshore production operations as the furthermost downstream point

where measurement for the purposes of calculating minerals severance occurs or there is a comingling of the flow stream from two or more wells.

The NPRM also would have required operators to request approval from the Associate Administrator of Pipeline Safety in order to extend gathering beyond the furthermost upstream gas processing plant. Finally, in order to address PHMSA's concerns with the lack of definite limits on the application of incidental gathering, PHMSA proposed limiting the distance that a gathering line could continue beyond a defined endpoint of gathering to 1 mile, provided that it does not cross a highway or railroad right of way.

2. Summary of Public Comments

NAPSR, the Pennsylvania Public Utility Commission (PAPUC), PST, EDF, and a member of the public all expressed support for elimination of API RP 80, citing the confusion that exists in the present document for defining the endpoints of gas production and processing facilities and gas gathering lines. Some of these commenters had concerns or suggested clarifications about specific issues. For example, NAPSR and other State pipeline safety officials suggested PHMSA clarify that authority to approve extending gathering beyond the first downstream natural gas processing plant (§ 192.8(a)(2)) or to use the point of comingling on fields greater than 50 miles apart (§ 192.8(a)(3)) resides with State pipeline safety agencies in addition to the PHMSA Associate Administrator for Pipeline Safety. The PAPUC commented that PHMSA should remove the point of gas comingling (the location where gas from two or more production sites join for further transportation downstream) from the proposed definition of an onshore production operation due to concerns that operators could use that concept to classify relatively large pipelines that are performing a gathering function as non-jurisdictional production lines.

API, The American Gas Association (AGA), IPAA, GPA Midstream, the Marcellus Shale Coalition, the Oklahoma Oil and Gas Association (OKOGA), the Domestic Energy Producers Alliance, and several individual pipeline operators commented that API RP 80 adequately delineated production and gathering lines on a functional basis and should not be eliminated from part 192. Most signaled that they would be open to collaboration to improve some definitional issues, especially via changes to API RP 80 through the collaborative API standards-revision process. To this end, API suggested initiating a revision of API RP 80 instead of using the proposed wording in the NPRM. Other industry groups and operators, such as the Virginia Oil and Gas Association and the Plastic Pipe Institute, opposed any modification to the current definitions and usage of API RP 80; these commenters contended that changing the start point of gathering would violate PHMSA's statutory limitation on regulating production lines, that State agencies adequately regulate intrastate production and gathering lines, or that PHMSA had not provided sufficient safety evidence to support changes to the definition of gathering.

Industry commenters also raised a number of specific concerns regarding the replacement definitions proposed by PHMSA. The most substantive comments concerned potentially ambiguous language in PHMSA's proposed definitions for ''onshore production facility or onshore production operation'' and ''gathering line (onshore).'' API opposed the proposed definitions but suggested edits that it claimed would provide more specificity to the types of processes that could be considered production functions. API also suggested clarifications on how points of comingling are treated in the definitions of the endpoints of gathering and production and make other changes. Other commenters requested clarification that the proposed definitions of gas processing plants and gas treatment plants did not apply to facilities on gas transmission or distribution lines. Many industry commenters requested a standalone definition of ''farm taps'' to clarify the regulatory requirements applicable to service lines connected to production, gathering, and transmission lines.

Many commenters opposed PHMSA's proposal to limit the use of the ''incidental gathering'' designation to one mile from the furthermost downstream point of gathering. API proposed a standalone definition of ''incidental gathering'' consistent with the current definition in API RP 80 and suggested that if PHMSA is concerned about particular lines abusing the definition of incidental gathering, then it should designate such incidental gathering lines as regulated gathering lines rather than generally restrict the use of the incidental gathering designation in API RP 80. It further suggested that the proposed Type A, Area 2 (now Type C) requirements could address safety concerns with large-diameter, high-pressure incidental gathering lines. API further commented that requiring operators to redesignate previously unregulated incidental gathering lines as transmission lines would result in significant costs, especially if the proposed gas transmission requirements in the NPRM applied to them. GPA Midstream commented that the ''proposed limitation of one mile is too restrictive,'' and that reclassifying existing gathering lines as transmission lines would result in substantial compliance costs that need to be addressed in the RIA. However, GPA Midstream and the OKOGA suggested that a 10-mile limit was a reasonable compromise that would establishes a definite limit on incidental gathering but with enough flexibility to accommodate different system configurations.

Industry commenters also contended that the implementation timeframe for identifying and reclassifying pipelines as regulated gathering lines (6 months) was too short.

3. GPAC Recommendation

The GPAC voted 11–0, with one abstention, that the proposed rule was technically feasible, reasonable, cost-effective, and practicable, if the proposed new and revised definitions related to gas gathering in § 192.3 and the proposed changes to § 192.8(a) for determining beginning and endpoints of gathering were withdrawn. PHMSA noted during the meeting that it will monitor the outcome of the working group preparing a second edition of API RP 80 and a new document, API RP 1182, ''Safety Provisions for Large Diameter Rural Gas Gathering Lines,'' and consider whether those efforts merit potential changes to the definition of gas gathering lines in a future rulemaking. Although the GPAC discussion acknowledged PHMSA's concerns regarding the ''incidental gathering'' concept in API RP 80, the GPAC did not discuss or recommend any particular mileage limitation on that concept. Likewise, the GPAC did not make any specific recommendations regarding the terms ''onshore production facility/operation'', ''gas processing plant'', ''gas treatment facility'', or ''gathering line (onshore)''.

4. PHMSA Response

PHMSA agrees with the majority of commenters and the GPAC that definitions of ''gas processing plant,'' ''gas treatment facility,'' and ''gathering line (onshore)'' should be omitted from the final rule. After the NPRM was published, API established two committees (API RP 1182 and API RP 80) to consider revisions to API RP 80 to address the same ambiguities in those

definitions that the NPRM was intended to address. Both documents have since published. The final rule does not repeal the use of the existing definition of gathering line based on API RP 80 (1st edition, 2000) and § 192.8. PHMSA will consider updating the definitions associated with defining gathering and production lines in a separate rulemaking after evaluating the second edition of API RP 80, *Definition of Onshore Gas Gathering Lines* and new API RP 1182, *Safety Provisions for Large Diameter Rural Gas Gathering Lines.* PHMSA declines to adopt in this rulemaking API RP 1182 or the 2nd edition of API RP 80 in their entirety without providing the public an opportunity to review and comment upon those standards. A few aspects of API RP 1182 have been adapted in the final rule, these are described in section III.C. of the preamble of this final rule.

However, due to safety and enforcement concerns, the final rule defines limits to ''incidental gathering'' on new, replaced, relocated, or otherwise changed gathering lines. The final rule changes the NPRM's proposed one-mile endpoint for the designation ''incidental gathering,'' but does impose a clear and defined limitation of ten miles on ''incidental gathering'' for any such pipelines constructed after the effective date of this rulemaking. Therefore, for gathering lines installed after the effective date of the rule, the ''connection to another pipeline'' endpoint in section 2.2(a)(1)(E) of API RP 80 may not be used if the connection is ten or more miles from the endpoints of gathering defined in paragraphs (a)(1)(A) through (a)(1)(D). In other words, if an ''incidental gathering'' portion of a newly constructed pipeline would be ten or more miles in length, then the incidental gathering concept may not be used and the gathering line terminates at the furthermost downstream endpoint defined in API RP 80 sections 2.2(a)(1)(A) through (a)(1)(d), subject to the limitations in § 192.8. While PHMSA appreciates the contribution of the API RP 80 committee on these definitional issues, ''incidental gathering'' concept is a significant source of uncertainty and concern that requires an immediate regulatory remedy to protect public safety. This limitation in the final rule immediately improves regulatory certainty regarding each of the endpoints of gathering and prevents potential abuse of the incidental gathering concept pending PHMSA's consideration of the second edition of API RP 80 and operational experience gained from implementation of the definitional changes in this final rule.

The purpose of API RP 80 was to define clear endpoints to the gathering and production lines based on their function and purpose and eliminate the circular definitions in part 192 at the time. While the definitions for the end of gathering in section 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 are not perfect, they provide some definite limits that are reasonably based on the function of the line in question. However, the incidental gathering concept negates both goals by allowing gathering to continue past what API itself defines as the end of gathering functions to the ''connection to another pipeline.'' This reintroduces the circular definitions in the original definition in § 192.3 that adoption of API RP 80 was intended to clarify. API RP 80 includes no limits to how far downstream the connection to another pipeline can be. As a result, PHMSA has observed supposedly incidental gathering lines that extend for several miles.

In addition to adding ambiguity to the regulations, unlimited application of incidental gathering creates a regulatory gap where long-distance pipelines that are functionally and operationally indistinguishable from transmission lines are classified as gathering lines with less stringent safety standards. By definition, an incidental gathering line is downstream of the last gathering function described in section 2.2 of API RP 80. Past that point the gas will not undergo further gathering-related processing or comingling. Incidental gathering can also include piping downstream of a major gas processing plant or a compressor used to increase downstream pressure so that the gas can be delivered to a transmission line (see section 2.2.1.2.4 of API RP 80); if that is the case, then the incidental gathering line is being operated at the same (high) pressure as the transmission line to which it is directly connected. In other words, such lines have functional and operational characteristics—including potential consequences—consistent with gas transmission lines, not production or gathering facilities. While some allowance to connect to nearby transmission facilities could be appropriate on economic or practicability grounds, this justification fades the further downstream it is applied.

In order to reduce this regulatory gap for gathering lines that are downstream of the last gathering function, the final rule limits incidental gathering to no more than 10 miles from the furthermost downstream endpoint of gathering for new, replaced, relocated, or otherwise changed pipelines. Specifically, PHMSA no longer allows the use of the ''connection to another pipeline'' endpoint in paragraph 2.2(a)(1)(E) of API RP 80 if it is 10 or more miles downstream of the furthermost of the other endpoints defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80. An ''incidental gathering'' pipeline installed after the effective date of the rule that extends beyond 10 miles shall be considered a transmission line, starting from the non-incidental endpoint of gathering defined in API RP 80. PHMSA currently uses a similar distance-based limit in § 192.8(a)(3) to set reasonable parameters for using the point of comingling, an actual gas gathering function, described in API RP 80 section 2.2(a)(1)(C) as an endpoint to gathering. While existing gathering lines are not affected by this change, such pipelines may be designated as Type C regulated gas gathering and subject to safety requirements, depending on their diameter, pressure, and operating environment (see sections III.C and III.D below).

Applying these limits on incidental gathering solely to only new, replaced, relocated, or otherwise changed gathering lines and revising the limit from 1 mile to 10 miles addresses the concerns raised by comments from operators while establishing a limit to incidental gathering going forward. Applicability to only new and replaced pipelines avoids disruption associated with reclassifying previously unregulated existing gathering lines as transmission lines and reduces the overall cost of the final rule for existing infrastructure. PHMSA recognizes that comments from operators broadly opposed the proposed 1-mile limit, and the GPAC did not recommend revisions to definition, including incidental gathering. However, as an alternative, a 10-mile limit was supported in public comments from GPA Midstream and OKOGA, trade associations for gas gathering line operators, and represents a reasonable first step towards establishing a firm endpoint to gathering. PHMSA also notes that a 10-mile limit on the ''incidental gathering'' concept would also be consistent with previous interpretation letters issued by PHMSA.[70] Extending the limit on incidental gathering to 10 miles provides greater flexibility for siting processing facilities and associated

[70] *See, e.g.,* PHMSA, Interpretation Letter No. PI–08–0010, Letter to State of Colorado Public Utilities Commission (Feb. 20, 2009) (endorsing use of ''incidental gathering'' concept for an 8-mile line), *https://cms7.phmsa.dot.gov/sites/phmsa.dot.gov/files/legacy/interpretations/Interpretation%20Files/Pipeline/2009/PI-09-0006.pdf.*

pipelines compared with the 1-mile limit in the proposed rule, addressing concerns raised in comments. PHMSA also notes that during this rulemaking process, there was support among both gathering line operators and public commenters to clarify the application of incidental gathering lines and impose common-sense limitations on the ''incidental gathering'' concept. Finally, as noted in the summary of comments, GPA Midstream and OKOGA submitted comments open to a 10-mile limit to incidental gathering rather than 1 mile as proposed in the NPRM.

Although the second edition of API RP 80 includes a 20-mile limitation to incidental gathering, PHMSA does not believe that newly constructed ''incidental gathering'' lines should be permitted to extend that far from a gathering facility. As explained in the NPRM, PHMSA has for more than a decade expressed concerns that the ''incidental gathering'' concept has been used to allow pipelines with certain characteristics (operating pressures, capacity, etc.)—and, consequently, risks to the public and the environment—resembling gas transmission lines to avoid part 192 regulatory requirements governing those lines. PHMSA does not, therefore, understand the 20-mile limit contemplated by API RP 80 to be as effective in capturing the safety and environmental benefits in comparison to what a more demanding mileage limitation would realize.

Further, PHMSA's discussion with various stakeholders revealed that there are very few incidental gathering lines that extend beyond 10 miles from the gathering facility; PHMSA is not aware of any, proposed new pipeline construction projects that would be classified as incidental gathering and extend 10 miles from the end of the gathering facility. The 10-mile limitation on incidental gathering, therefore, provides regulatory certainty to stakeholders, recognizes uncertainty regarding the cost impacts that could arise if incidental gathering is limited to 1 mile and on existing gas gathering lines, as proposed, and ensures that the regulatory gap that currently exists with regard to API RP 80's absence of a limitation on incidental gathering is closed for all newly constructed lines. PHMSA acknowledges that a regulatory gap remains for existing incidental gathering lines and new and replaced incidental gathering lines 10 miles or shorter. However, both new and existing incidental gathering lines with the highest potential safety hazards are either covered by existing safety standards for Type A and Type B regulated gas gathering lines in Class 2, Class 3, and Class 4 locations, or the new safety standards for Type C regulated gas gathering lines in Class 1 locations established by this final rule. These requirements are described in sections III.C and III.D. of the preamble to this final rule. PHMSA will reconsider the issue of definitions, including the endpoint of production and treatment of incidental gathering lines, in a separate rulemaking in order to ensure stakeholders are able to comprehensively comment on newly proposed definitions and the second edition of API RP 80. Infrastructure and incident data collected as a result of this rulemaking, inspection data, and the public comment process will help inform future limits to incidental gathering.

C. Expanded Scope of Gas Gathering Line Regulations—§ 192.8

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to create a new category of Type A regulated gas gathering lines in Class 1 locations that had a nominal diameter of 8 inches (actual outside diameter of 8.625 inches) or greater. This new category of regulated gathering lines was identified in the table of the proposed § 192.8 as ''Type A, Area 2'' (in the final rule it is referred to as Type C), lines. PHMSA proposed to define Type A, Area 2 regulated gathering lines as gathering lines located in Class 1 locations that meet the existing Type A features in the table in § 192.9(b) (*i.e.,* metallic with an MAOP that produces a hoop stress of 20 percent or more of SMYS, or non-metallic with an MAOP greater than 125 psig) that have a nominal pipe size of 8 inches or greater.

This change was intended to improve the safety of larger-diameter, higher-stress gathering lines that were previously exempt from Federal safety regulations at part 192. In the NPRM, these newly designated Type A, Area 2 (Type C) regulated gathering lines would have to comply with a basic set of requirements as set forth in § 192.9. The specific requirements for newly regulated gas gathering lines are discussed in section III.D of this document.

2. Summary of Public Comment

API, the Michigan Public Service Commission (Michigan PSC), the Texas Pipeline Association (TPA), and Atmos Energy Corporation (Atmos) recommended that more data should be collected before determining the appropriate scope of additional regulations. The PAPUC supported the extension of regulatory oversight to gathering lines in Class 1 locations, based on its experience with growing natural gas production in Pennsylvania, noting that gathering lines are being constructed with diameters equal to or larger than typical transmission lines and are being operated at much higher pressures than was typical in the past. NAPSR supported the proposed scope of the new gathering line requirements but also commented that its members believe all gathering lines should be required to comply with part 192, regardless of class location. Some environmental and safety groups also expressed support for the extension of regulations to gas gathering lines in Class 1 locations in order to reduce the risks of incidents, greenhouse gas emissions and other air pollution. For example, EDF supported requirements for the design, installation, construction, initial inspection and testing, corrosion control, damage prevention and leakage surveys in order to reduce methane emissions.

The North Dakota Petroleum Council, the Marcellus Shale Coalition, the AGA, the Plastics Pipe Institute (PPI), Spectra Energy Partners, API, GPA Midstream, the Northeast Gas Association, and some individuals submitted comments noting issues and uncertainty with the regulatory impact assessment. For example, GPA Midstream commented that the benefits analysis included information for offshore and Class 2 incidents that are not applicable to the proposed scope of this final rule and that the cost analysis underestimated the time and cost to identify newly regulated gathering lines in a short amount of time and comply with the new requirements, especially MAOP determination and public awareness. Many operators and industry groups expressed disagreement with applying regulations to all Class 1 gas gathering lines with outer diameters of 8.625 inches or greater, arguing that gathering lines on the smaller end of that category do not represent the large-diameter, high-pressure gathering lines referenced in the preamble of the NPRM and public discussions. API commented that if PHMSA does proceed with defining a new category of regulated gathering lines, gathering lines with outer diameter greater than 16 inches have the potential to pose a higher risk and should be the criteria for determining regulated gathering, rather than 8 inches. API further suggested that targeting lines with outer diameters greater than 16 inches would be more in the spirit of the risk-based philosophy of other parts of the code, such as integrity management. This suggestion was

repeated by GPA Midstream, the North Dakota, Petroleum Council, and others.

A number of commenters representing the pipeline industry expressed concerns with the deadlines to identify newly regulated gathering lines and then comply with the proposed regulations. For example, Rice Energy, Dominion East Ohio, API, and GPA Midstream commented that the implementation timeframe for identifying proposed Type A, Area 2 (now Type C) regulated gathering lines was too short. Industry commenters were especially concerned about the deadline to establish an MAOP, especially if the MAOP verification requirements proposed for gas transmission lines in the NPRM also applied to gathering lines. One commenter suggested an economic criterion to allow an exemption for operators of economically marginal, low stress gathering lines.

Some commenters expressed the view that the proposed Type A, Area 2 (now Type C) classification for newly regulated gas gathering lines could be confusing. Specifically, commenters found that designating newly regulated gas gathering lines as Type A, Area 2 (now Type C), and then requiring those pipelines to follow requirements similar to Type B rather than existing Type A requirements was cumbersome and risked conflating distinct regulatory requirements. A few commenters suggested a Type C designation rather than the proposed Type A, Area 2 (now Type C) designation. The GPAC recommended PHMSA address these concerns in the final rule.

3. GPAC Recommendation

GPAC voted 11–1 that the scope of newly regulated gas gathering lines in proposed § 192.8(b) and (c) is technically feasible, reasonable, cost-effective, and practicable if PHMSA considered the following:

- Establishing an initial framework for regulating Class 1 gathering lines that could be built upon in light of future information and experience;
- Setting a minimum set of requirements for gathering lines 8.625 inches in outside diameter and greater (considering, for example: Damage prevention; line markers; public awareness; leak surveys and repairs; design, installation, construction, and initial inspection and testing for new lines; and emergency plans). Give due consideration to the GPAC discussion on the costs and benefits of performing leakage surveys;
- Consider applying a PIR concept and additional requirements to provide safety and environmental protection for larger- diameter gathering lines (*e.g.,* greater than 12.75 inch outside diameter); and
- Ensuring that composite pipe [71] was adequately addressed to minimize the impact on its continued use. Note that this is discussed in section III.D below.

4. PHMSA Response

In response to public comments and the recommendations of the GPAC, PHMSA has changed the proposed ''Type A, Area 2'' designation for newly regulated gas gathering lines to ''Type C'' lines. PHMSA originally proposed use of the term ''Type A, Area 2'' (now Type C) because the newly regulated gas gathering lines have features similar to existing Type A pipelines in the table in § 192.8, except that they are located in Class 1 locations. However, PHMSA agrees that creating the category ''Type C'' may be less confusing. While adopting the new designation of Type C regulated gas gathering lines introduces some repetition in the table in § 192.8, PHMSA believes it will make clearer that the three categories represent different levels of risk that warrant corresponding levels of regulation and will reduce unnecessary confusion among operators and inspectors in the future.

The final rule continues to define Type C regulated gas gathering lines as gas gathering lines in Class 1 locations that are 8.625 inches or greater in diameter and are: (1) Metallic, with an MAOP producing a hoop stress of 20 percent or more of SMYS; (2) metallic, with an MAOP greater than 125 psig if the hoop stress is unknown; or (3) non-metallic, with an MAOP greater than 125 psig. However, PHMSA recognizes that not all gathering lines that meet these criteria pose the same level of risk. Therefore, the final rule provides that the requirements that Type C gathering lines must comply with will vary, based on the scale of risk associated with the particular characteristics of the pipeline. The applicability of each of the requirements that potentially applies to Type C lines is described in section III.D below and the section-by-section analysis. Gathering lines smaller than 8.625 inches in outside diameter or operating below the pressure or stress level criteria described above will remain unregulated under part 192 and are subject only to incident and annual reporting in part 191 (see section III.A below).

As described in the background section (II.A) above, modern gathering systems require larger, higher-pressure lines to meet the new supply and demand pressures than had been common when the existing requirements were put into place. This is not a theoretical problem: Failures on unregulated gas gathering lines have resulted in serious incidents, some with fatal consequences (see the discussion in section II.A above).

PHMSA appreciates the need to exercise caution in exercising its statutory authority to regulate gathering lines that have not been previously covered by parts 191 and 192 without clear, detailed safety data. This is why a new category of gathering lines is being created for reporting purposes only that are only subject to the incident and annual reporting requirements described in section III.A of this document. These are designated as ''Type R'' gathering lines in § 192.8. These lines are not regulated gathering lines under in part 192 but are subject to incident and annual reporting requirements in part 191.

However, there is ample basis upon which to add the targeted requirements in this final rule for Type C gathering lines that mirror the requirements already in place for existing, lower-stress Type B lines. These measures are an appropriate initial step to ensure basic safeguards to the public, property, and the environment while additional data is collected and analyzed. Additionally, withdrawing the proposed regulations in the NPRM for previously unregulated gas gathering lines in its entirety would be inconsistent with public safety and would not be responsive to GAO recommendation GAO–14–667 or the Congressional mandate in the 2020 PIPES Act. Therefore, PHMSA is adding the definition of Type C regulated gas gathering lines as proposed in the NPRM.

However, the new regulatory requirements are tailored to the potential hazards the newly regulated gathering lines may pose. This is described in more detail in section III.D below. PHMSA determined that certain programs, such as damage prevention, are foundational to pipeline safety and public trust and therefore should be required for all Type C gas gathering lines as originally proposed in the NPRM. However, other requirements apply only to Type C lines with an outside diameter greater than 16 inches, and Type C lines with an outside

[71] A composite pipe is made of a combination of either steel or plastic with a reinforcing material designed to maintain its circumferential and longitudinal strength. A common configuration consists of steel or fiber reinforcement layered between a polymer inside liner and outer shell. No composite materials are currently authorized for use in part 192 or part 195, but may be used through a special permit (*see* § 190.341).

diameter larger than 12.75 inches that are located near homes and other structures. The largest-diameter gas gathering lines and those that can directly impact local communities are required to comply with all of the requirements for newly regulated Type C (Type A, Area 2) gathering lines proposed in the NPRM. The proposed deadline to determine endpoints of newly regulated gathering lines remains unchanged in the final rule—6 months after the effective date. Operators must therefore identify the endpoints of newly regulated Type C lines on or before November 16, 2022. While the GPAC recommended a 2-year compliance deadline for identifying the endpoints of Type C gathering lines, such a delay is not necessary given that PHMSA understands that many Type C lines are of more recent vintage and therefore would generally have more robust records to facilitate determination of endpoints than older gathering lines. A prolonged identification period would also delay the important safety (section III.D. *infra*) and reporting (section III.A.4. *supra*) standards in the final rule. The Type C determination in § 192.8(c)(2) requires, at a minimum, knowledge only of the location, diameter, and pressure of the pipeline. Most Type C gathering lines are relatively modern shale gas systems and these basic records should be readily accessible.

PHMSA acknowledges that this deadline may be challenging for some operators of certain older, smaller-diameter, systems. The final rule therefore includes procedures for an operator to request an alternative compliance deadline with a notification in accordance with § 192.18. This is intended to mirror existing § 192.9(e)(2), which gives the PHMSA Administrator discretion to allow a later deadline if justified in a particular case. An operator must submit a written request to PHMSA in accordance with § 192.18 no later than 90 days prior to the standard compliance deadline. The request must include, at a minimum, a description of the facilities that require a delayed compliance date, the justification for an alternative compliance deadline, and the proposed alternative compliance deadline. An operator may proceed with their proposed compliance deadline if they receive a no-objection letter from PHMSA or if PHMSA does not reply within 90 days. If delayed identification impacts an operator's ability to comply with the requirements in § 192.9, they must submit a separate notification to request delayed compliance under that section.

The combination of changes discussed in this section and in section III.D below provides a reasonable and cost-effective initial approach to address the risks associated with previously unregulated gas gathering lines. PHMSA will monitor the safety performance of both newly regulated gas gathering and unregulated gas gathering lines and evaluate the need for further regulatory action in the future.

D. Safety Requirements for Newly Regulated Gas Gathering Lines—§§ 192.9, 192.13, 192.18, 192.452, and 192.619

1. Summary of PHMSA's Proposal

PHMSA proposed in the NPRM to apply part 192 safety requirements to the newly-established Type A, Area 2 lines (referred to as Type C lines in the final rule). These requirements, collectively referred to as Type C requirements in this final rule, are:

- § 192.9(d)(1)—Implement design, installation, construction, initial inspection, and initial testing requirements for new/replaced/relocated/changed lines in accordance with the requirements in part 192 for transmission lines.
- § 192.9(d)(2)—Adopt corrosion control measures for metallic pipe in accordance with part 192, subpart I, requirements for transmission lines.
- § 192.9(d)(3)—Adopt damage prevention measures in accordance with § 192.614.
- § 192.9(d)(4)—Develop public awareness programs in accordance with § 192.616.
- § 192.9(d)(5)—Establish MAOP in accordance with § 192.619.
- § 192.9(d)(6)—Install and maintain line markers in accordance with the requirements for transmission lines in § 192.707.
- § 192.9(d)(7)—Conduct leakage surveys in accordance with § 192.706, using leak- detection equipment and promptly repair hazardous leaks that are discovered, in accordance with § 192.703(c).
- § 192.9(d)(8)—Develop and implement procedures for emergency plans in accordance with § 192.615.

These requirements are the same as those that currently apply to Type B regulated gas gathering lines, except for the new emergency plans requirements. PHMSA also proposed conforming changes to §§ 192.13, 192.452, and 192.619.

2. Summary of Public Comment

Citizen and environmental groups expressed support for the proposed requirements for newly regulated gas gathering lines or suggested additional requirements. Several citizen groups suggested that gas gathering lines that function similarly to transmission lines should be regulated like transmission lines in part 192. Similarly, the Public Service Commission of West Virginia commented that the proposed requirements for Type A, Area 2 (now Type C) lines, which mirror the requirements for low-pressure, low-stress Type B gathering lines, are not adequate or sufficient to ensure the safety of large, high-pressure gas gathering lines and instead recommended that such pipelines follow existing Type A, Area 1 requirements (*i.e.* most gas transmission line requirements) that apply to other regulated gathering lines that operate with higher stress levels and pressures.

GPA Midstream and Kinder Morgan commented that Type A, Area 2 (now Type C) lines should not have to conduct leakage surveys with leak detection equipment, as currently required for Type B gathering lines in § 192.9(d)(7), since leaks and ruptures on higher-stress Type A lines are easier to detect without specialized equipment. API and TPA proposed that the emergency-planning requirements in § 192.9(d)(8) be revised to reference the existing requirements for other types of pipelines in § 192.615. They also recommended exempting operators of Type A, Area 2 (now Type C) regulated gathering lines from the requirement to have written procedures to respond to each of the emergency situations listed in § 192.615(a)(3), presumably for cost concerns. API, GPA Midstream, and Northeast Gas Association commented that the compliance cost estimates used in the RIA for Type A, Area 2 (now Type C) regulated gathering lines were underestimated and contained erroneous assumptions. For example, GPA Midstream raised concerns about the costs of program evaluation requirements under public awareness. Industry commenters were especially concerned about the applicability of the proposed gas transmission requirements in the NPRM such as the MAOP reconfirmation, including the cost to establish MAOP and confirm the material properties of gathering lines that were not previously required to have an MAOP or keep such records. PHMSA notes that these provisions were finalized by the Gas Transmission Final Rule and apply only to gas transmission lines.

A number of commenters articulated concerns about how the proposed regulations would affect the use of non-metallic materials in previously

unregulated gathering systems. Commenters representing gathering line operators and non-metallic pipe manufacturers urged PHMSA to consider the impact of the rule on gathering lines made of composite materials and polyethylene pipe manufactured to standards other than ASTM D2513. A composite pipe is made of a combination of either steel or plastic with a reinforcing material designed to maintain its circumferential and longitudinal strength. A common configuration consists of steel or fiber reinforcement layered between a polymer inside liner and outer shell. No composite materials are currently authorized for use in part 192 or part 195 but may be used through a special permit (see § 190.341).

Commenters were especially concerned with the possibility that existing, unregulated lines made of non-metallic materials would need to be replaced if they subsequently become regulated Type A, Area 2 (Type C) lines. API suggested that PHMSA incorporate by reference two standards, API Standard 15S, ''Spoolable Composite Pipe Systems,'' 1st edition and ASTM F2619/F2619M–13, ''Standard Specification for High-Density Polyethylene (PE) Line Pipe'' into § 192.9 to allow the use of composite materials and an alternative specification for polyethylene pipe that is commonly used in unregulated production and gathering operations. API and the Plastic Pipe Institute commented that the proposed repair criteria in the NPRM did not address non-metallic materials and could effectively eliminate the use of plastics and composites in Type A, Area 2 (now Type C) lines that previously had no such restrictions. GPA Midstream also commented that composite pipe can operate at pressures that would include them within the Type A, Area 2 (now Type C) criteria and should therefore be addressed in the rule.

3. GPAC Recommendations

GPAC voted 12–0 that the proposed minimum safety standards for Type A, Area 2 (Type C) regulated gathering lines were technically feasible, reasonable, cost-effective, and practicable, if the following changes were made:

- Extend the deadline for Type A, Area 2 (Type C) gathering lines that become regulated in the future due to new dwellings to comply with part 192 requirements from one year to two years after the effective date of the final rule;
- Add a notification process similar to the process endorsed by the committee for the gas transmission rule [72] to address the use of composite pipe materials in existing and new Type A, Area 2 (Type C) gathering lines;
- Extend the deadline in § 192.8(b) for determining if pipelines are classified as Type A, Area 2 (Type C) gathering lines from six months to two years after the effective date of the final rule;
- Extend the deadline for newly regulated gas gathering lines to comply with Type A, Area 2 (Type C) requirements to three years after the effective date of the rule, and make conforming changes (§§ 192.9(e)(3) and (4), 192.452, 192.13, and 192.619);
- Ensure that the language for designating newly regulated gas gathering lines is as clear as possible (*e.g.,* Type C vs. Type A, Area 2);
- Allow operators of Type A, Area 2 (Type C) gas gathering lines to establish MAOP based on a five-year high operating pressure; or via an alternative method with notification to PHMSA (§ 192.18 process); and
- Modify § 192.9 (d) to include Type A, Area 2 (Type C) gathering lines.

4. PHMSA Response

PHMSA understands the concerns expressed by the commenters regarding the application of existing pipeline safety requirements to newly regulated gas gathering lines. While the final rule does not significantly change the NPRM's proposed criteria for designating newly regulated Type C gas gathering lines (higher stress gathering lines with an outside diameter of 8.625 inches or greater, see section III.C), it does make changes to the NPRM's proposal regarding how each of the proposed Type C requirements are to be applied. These changes focus on applying more requirements to the highest-risk, largest-diameter gathering lines. The risk-based approach to Type C requirements in this final rule is based upon discussions at the June 25th GPAC meeting, consideration of the public comments received on the NPRM, and an analysis of the costs and benefits of various alternatives (see the RIA, available in the docket for this rule, for a detailed description of alternatives considered). As discussed during the GPAC meeting, PHMSA emphasizes that the Type C requirements are an initial step in addressing safety concerns with larger-diameter gas gathering lines. If PHMSA's analysis of the safety performance of regulated and unregulated gathering lines demonstrates a need to revise the requirements for regulated gathering lines, PHMSA can exercise its authority to do so in a future rulemaking.

The applicability of each of the requirements for Type C regulated gas gathering lines in the final rule is as follows:

Requirements for Type C gathering lines with outside diameters of 8.625 inches and greater:

- Design, installation, construction, and initial inspection and testing for lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 per transmission line requirements in part 192;
- Corrosion Control (part 192, subpart I);
- Damage Prevention Program (§ 192.614);
- Emergency Plans (§ 192.615);
- Public Awareness (§ 192.616);
- Line Markers (§ 192.707); and
- Leakage Surveys (§ 192.706).

Additional requirements for Type C gathering lines with outside diameters greater than 12.75 inches:

- Applicable requirements of part 192 for plastic pipe and components; and
- Establishment of MAOP (§ 192.619).

Exception: Gathering lines with an outer diameter 16 inches or less that are not located within a potential impact circle containing a building intended for human occupancy or other impacted sites must only comply with requirements governing damage prevention (§ 192.614); emergency plans (§ 192.615); and, for Type C lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 (*i.e.* 1 year after the effective date of the rule), certain design, installation, construction, initial inspection, and initial testing requirements applicable to transmission lines under part 192. These provisions are required for all Type C gathering lines regardless of size or location. The applicability of each of these requirements is summarized in the table below:

[72] This recommendation was subsequently codified as § 192.18 by the Gas Transmission Final Rule (84 FR 52180).

Outside diameter	*Not* located near a building intended for human occupancy or other impacted site (§ 192.9(f))	Located near a building intended for human occupancy or other impacted site (§ 192.9(f))
Greater than or equal to 8.625 inches up to and including 12.75 inches.	—Design, Construction, Initial Inspection and Testing (new/replaced/relocated/changed lines). —Damage Prevention —Emergency plans	—Design, Construction, Initial Inspection and Testing (new/replaced/relocated/changed lines). —Corrosion Control. —Damage Prevention. —Emergency Plans. —Line Markers. —Public Awareness. —Leakage Surveys.
Greater than 12.75 inches up to and including 16 inches.	—Design, Construction, Initial Inspection and Testing (new/replaced/relocated/changed lines). —Damage Prevention. —Emergency Plans.	All Type C Requirements.
Greater than 16 inches	All Type C Requirements	All Type C Requirements.

The potential impact circle calculation criterion for certain Type C requirements is based on the method for identifying high-consequence areas in the gas transmission integrity management program regulations in subpart O of part 192. Specifically, the terms ''potential impact circle'' and ''potential impact radius (PIR),'' including the formula for calculating what the length of the potential impact radius,[73] are defined in § 192.903. The ''potential impact circle'' is the area around a pipeline where a pipeline rupture could cause severe consequences, such as casualties and destruction of property. PHMSA notes that the formula requires knowing the MAOP of the pipeline, rather than the actual operating pressure. Additionally, the final rule requires that operators of Type C gathering line use a factor of 0.73 for wet/rich natural gas in the PIR calculation rather than the 0.69 factor for dry natural gas used in the integrity management regulations. This results in a slightly larger potential impact circle reflecting the potentially more intense fire and explosion hazards due to the higher average energy content of unprocessed gas, which may contain higher concentrations of natural gas liquids and other hydrocarbons. A 2005 report prepared for PHMSA by Michael Baker Jr., Inc., titled, ''Potential Impact Radius Formulae for Flammable Gases other than Natural Gas Subject to 49 CFR 192'' [74] calculated that 0.73 was an appropriate PIR factor for pipelines transporting rich natural gas. The calculations are detailed in section 4.8.4 of the report using the same formula described in ASME B31.8S that is referenced in the gas transmission integrity management regulations. API RP 1182 uses the same factor for a similar PIR concept, however that document is not incorporated by reference in this rule. Similarly, § 192.9(f) in this final rule dictates that any Type C gathering line segment located within a potential impact circle containing a building intended for human occupancy or other impacted site must comply with all Type C requirements applicable for the diameter of that line, since a failure on that segment has the potential to cause catastrophic damage to local communities. This approach was discussed at the GPAC and in public comments and PHMSA agrees it is an effective way of prioritizing short-term regulatory action towards gas gathering lines with the highest potential consequences of a failure.

PHMSA recognizes that not all operators may be able to perform the potential impact radius calculation. If the gathering line segment does not have an established MAOP or other records necessary to perform the PIR calculation, the operator may perform the same determination on a class location unit (see § 192.5) basis rather than a potential impact circle basis. A class location unit is 1 mile in length and extends 220 yards on either side of the centerline of a pipeline. PHMSA notes that this uses the same ''sliding mile'' approach used for determining class locations rather than static mile-long increments stacked end-over-end. The class-location unit moves along the pipeline, and if the sliding mile contains a building intended for human occupancy or other impacted site at any point during the mile's movement, then the exception in paragraph (f) does not apply for the entire mile of pipeline contained within the sliding mile.

The class location unit method for applying these exceptions is used in API RP 1182 and provides a simpler, more conservative method for determining the applicability of the § 192.9(f) exception for operators that choose not to perform a PIR analysis or lack records of the parameters necessary to calculate the PIR. PHMSA expects that the class location unit method will result in fewer miles of gathering lines being covered by the § 192.9 exception in almost all circumstances because the additional requirements will apply for a mile on each side of a building intended for human occupancy or other impacted site. Theoretically, the PIR of a pipeline could exceed 220 yards; if this is the case it is possible that some structures could be captured by the PIR analysis but not the class location unit analysis. However, given that this exception is limited for Type C gathering lines 16 inches or less in outside diameter, it is unlikely that a gathering line 16 inches or less in diameter will operate at a pressure that would cause the calculated PIR to exceed the width of the class location unit. The MAOP of a pipeline with an outside diameter of 16 inches must exceed 3000 psig for the PIR of the pipeline to exceed 660 feet. A MAOP of 3000 psig is unusually high. Although PHMSA does not collect data on MAOP on annual reports, incident reports reveal that less than 1 percent of gas transmission incidents from 2010 through the end of 2021 involved a facility with an MAOP higher than 3000 psig; further, there were no incidents volving a pipeline larger than 10.75 inches in outside diameter, and no incidents on regulated onshore gas gathering lines.

In the final rule, operators must achieve compliance with applicable Type C requirements no later than 1

[73] *See* ASME B31.8S for additional information on calculating PIR.

[74] Michael Baker Jr., Inc. ''TTO Number 13: Potential Impact Radius Formulae for Flammable Gases Other than Natural Gas Subject to 49 CFR 192: Final Report'' (June 2005), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-transmission-integrity-management/65311/tto13potentialimpactradiusfinalreportjune2005.pdf.*

year after the effective date of the rule, unless PHMSA has approved an alternative compliance schedule after the operator has submitted a notification in accordance with § 192.18. This is a shorter compliance deadline than the 3-year phase in recommended by the GPAC (*i.e.,* 1-year after the endpoints of Type C have been identified). The safety standards in the final rule target known threats to public safety, and the most significant requirements are targeted at gathering lines with direct potential safety impacts (*i.e.,* has a potential impact circle containing a building intended for human occupancy). Due to these direct threats to the public, it is critical that operators implement minimum safety practices as soon as practicable. The final rule provides operators a total of 1½ years from the date of publication to implement these measures, which should be achievable for most operators.

However, PHMSA recognizes that some operators may encounter challenges in meeting the deadline for one or more of the Type C requirements. The final rule therefore includes procedures for an operator to request an alternative compliance deadline with a notification in accordance with § 192.18. This is intended to mirror existing § 192.9(e)(2), which allows the PHMSA Administrator flexibility to provide a later deadline if justified in a particular case. An operator must submit a written request to PHMSA in accordance with § 192.18 no later than 90 days prior to the standard compliance deadline. The request must include, at a minimum, a description of the facilities that require a delayed compliance date, the proposed alternative deadline, justification for the alternative compliance deadline, and actions the operator will take to ensure the safety of the affected facilities in the interim. The description of the pipeline facility and the operating environment should include relevant information about the integrity of the pipeline and the potential consequences in the case of the release. This includes: The diameter of the pipeline; the operating pressure; known design and construction specifications; results from surveys, patrols, or integrity assessments; and the presence of homes or other human uses near the pipeline. An operator may request an alternative compliance schedule for more than one requirement within § 192.9(e) in a single notice. However, the notice must include a proposed compliance schedule and justification for each requirement. An operator may proceed with their proposed compliance deadline if they receive a no-objection letter from PHMSA or if PHMSA does not reply within 90 days.

Consistent with the deadlines described above, design, construction, initial inspection, and initial testing requirements apply to all Type C lines that are new, replaced, relocated, or otherwise changed after the applicable compliance deadline in § 192.13 (*i.e.,* 1 year after the effective date of the rule). Additionally, in the final rule, operators of unregulated gas gathering lines that become Type C regulated gathering lines, or become subject to additional Type C requirements, due to a change in the pipeline's MAOP or the discovery of a building intended for human occupancy or other impacted site have 1 year from the time the change is discovered to comply with Type C requirements.

PHMSA determined that it was appropriate for all Type C gathering lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 (*i.e.,* 1 year after the effective date of the rule) to comply with the initial design, construction, inspection, and testing requirements applicable to transmission lines in part 192 to ensure that new, higher risk gathering lines are adequately designed and constructed. PHMSA also determined that it was appropriate for all Type C gathering lines to comply with damage prevention and emergency plan requirements in §§ 192.614 and 192.615, based on the incident history of transmission pipelines and fatal gas gathering incidents. For onshore gas transmission lines between 2010 and 2019, excavation damage was the third leading cause of incidents and the most common cause of incidents that resulted in fatal injuries.[75] As described in section II.A, many of the fatal incidents on unregulated gathering lines described in media reports have been caused by excavation damage. These incidents commonly cause serious and fatal injuries regardless of the diameter or location of the pipeline since equipment operators and other workers may be in close proximity to the point of failure. However, effective damage prevention programs and participation in One-Call programs can reduce this risk. Based on gas transmission line incident report data, both the number of excavation damage incidents and the share of incidents caused by excavation damage has trended downwards between 2000 and 2018. While gathering lines are covered under damage prevention and One-Call laws in most States, PHMSA expects that requiring operators to implement a damage prevention program under part 192 may improve enforcement of these requirements and cover lines in States where gathering lines are excepted. Maintaining a written damage prevention procedure and communicating damage prevention information to the public may also result in safety benefits beyond compliance with State One-Call laws from operators and excavators becoming more cognizant of the risks of third-party damage to gathering lines.

The requirements for emergency plans in § 192.615 directly address concerns with operator and community emergency response and planning capability. Emergency response plans and procedures for rural gathering lines were areas of emphasis in GAO's August 2014 report on safety requirements for transporting energy products.[76] In that report, the NTSB, a representative of the National Association of State Fire Marshals and emergency response officials agreed that ''emergency response plans are critical for pipeline safety;'' however, those emergency officials were concerned that responders in rural areas lacked the information about unregulated gathering lines in their communities to prepare for and respond to pipeline emergencies. Requiring all Type C gathering lines to comply with § 192.615 addresses these concerns by bringing emergency planning requirements for such pipelines in line with existing requirements for gas transmission lines.

PHMSA disagrees with the comment that Type C gas gathering lines should be excepted from the requirement to develop and follow procedures for responding to common types of pipeline emergencies listed in § 192.615(a)(3), such as gas leaks in structures, fires, explosions, and natural disasters. This requirement is necessary to help ensure effective emergency preparedness. As described in the background section II of this document and the GAO–14–667 report, emergency response capabilities are especially important for gas gathering systems operating in communities that do not have experience with intensive oil and gas development.

Design, installation, construction, initial inspection, and initial testing

[75] Out of 1,057 incidents reported to PHMSA that occurred during this period, 150 were due to excavation damage. Of the 13 incidents that resulted in fatal injuries, 6 were caused by excavation damage.

[76] GAO, GAO–14–667, ''Oil and Gas Transportation: Department of Transportation is Taking Actions to Address Rail Safety, but Additional Actions are Needed to Improve Pipeline Safety'' (Aug. 2012).

requirements, and corrosion control measures in part 192 are intended to reduce the likelihood of a release caused by material and equipment failure, corrosion, and excavation damage. Design, installation, construction, initial inspection, and initial testing requirements are prospective only. Operators are not expected to replace facilities existing on or prior to the compliance deadline in § 192.13 (*i.e.,* 1 year after the effective date of the rule) in order to comply with these requirements. PHMSA expects there will be safety benefits from applying part 192 design, construction, initial inspection, and initial testing requirements should those existing lines require replacement, relocation or otherwise be changed.

In the NPRM, PHMSA did not intend to prohibit the use of composite pipe materials on previously unregulated Type C gathering lines or require the removal of such materials. However, the existing part 192 requirements were written for steel or conventional plastic pipe. Additionally, the NPRM did not propose to incorporate by reference API RP 15S or F2619/F2619M–13 and PHMSA has not yet conducted the technical review of those documents needed to support their incorporation by reference in this final rule.

To address composite pipe, PHMSA has added a provision in the final rule to allow operators to install or replace composite pipe that is not otherwise authorized by part 192 for use in regulated Type C gas gathering lines upon notification to PHMSA pursuant to §§ 192.9(h) and 192.18. Operators may use composite pipe or materials as proposed in their notification if, after 91 days, they have not received a letter from PHMSA with either an objection to the proposed use of composite pipe, or that states that PHMSA requires additional time to conduct its review. PHMSA may also proactively issue a no-objection letter. Additionally, operators may continue to use composite pipe installed on or before the effective date of the rule; no notification under §§ 192.9(h) and 192.18 would be required in those circumstances. This change affects Type C gathering lines only and does not authorize the use of composite pipe for any other type of pipeline covered under part 192. Under the § 192.18 notification process, PHMSA will evaluate the operator's proposed operation and maintenance procedures, which includes the operator's proposed remediation methods and procedures for identifying defects and determining the safe operating pressures of composite pipe when defects are found. PHMSA will not approve notifications that it determines are inconsistent with pipeline safety. An objection letter issued under § 192.18 will not foreclose an operator's ability to seek a special permit in accordance with § 190.341. Additional information on this process is provided in the section-by-section analysis of this document. PHMSA may use data obtained from observing the design, construction, and operation of composite materials in Type C gathering lines to inform its future decisions on whether and how to accept composite materials for pipelines in other jurisdictional applications.

Public awareness requirements in § 192.616 and line marker requirements in § 192.707 apply to Type C lines that are located near buildings intended for human occupancy, and further address residual risks despite part 192 damage prevention and emergency planning requirements. Public awareness requirements in § 192.616 require additional communication with excavators, first responders, local governments, and the public. Notably, this provision at § 192.616(d) obliges operators to describe the potential hazards of a pipeline release, the physical markers of a release, and how to respond to customers and other members of the community. This requirement is especially important for members of the public to identify dangerous releases on gas pipelines that are not odorized. These communications improve safety by encouraging individuals to take safe actions such as contacting One-Call before performing excavations and recognizing, avoiding, and reporting gas leaks. Section 192.707 requires the placement of line markers at road and railroad crossings, and wherever else the operator deems is necessary. These markers provide a visual reminder of the presence of otherwise invisible pipelines and serve to reduce third-party damage risks. Additionally, during emergencies, line markers communicate hazards and operator contact information to first responders.

After consideration of public comments, the recommendations of the GPAC, and the final RIA that accompanies this final rule, PHMSA has retained the requirement for leakage surveys in § 192.706 for both (1) all Type C gathering lines with an outside diameter greater than 16 inches, as well as (2) Type C gathering lines with an outer diameter greater than 8.625 inches but not exceeding 16 inches in outside diameter that are located in a potential impact circle containing a building intended for human occupancy or other impacted site. In other words, this requirement applies to larger-diameter gas gathering lines and those that could directly impact nearby structures and people during a rupture. Since Class 1 gas gathering lines are not typically odorized and the leakage survey requirement applies to larger diameter Type C gathering lines or those located near people, PHMSA has retained the requirement that operators use leak detection equipment when conducting leakage surveys. Leak detection equipment is already required for leakage surveys on gas transmission lines that are not odorized.

Part 192 does not currently establish technology or performance standards for leak detection equipment, and the NPRM did not propose to establish standards for leak detection equipment. The final rule therefore does not specify what constitutes ''leak detection equipment.'' Any equipment capable of detecting all leaks on the pipeline system would be acceptable.[77] Traditionally, operator personnel perform an instrumented leakage survey by walking along the pipeline right-of-of way with handheld leak detection equipment, such as a flame ionization detection device, laser-based methane detector, or other equipment. Similar equipment can be installed on vehicles or at fixed locations along the right of way. Some technology providers claim to detect smaller leaks from greater distances using a combination of vehicular or aerial sensor platforms, sensitive gas detectors, other sensors, and analytics. There are also various methods for continuous leak monitoring, including pressure and pressure wave monitoring, fixed gas detectors, and fiber optic-based distributed sensing. Performing leakage surveys increases the likelihood that small defects are discovered and remediated before they evolve into more significant failures with potentially severe impacts to people, nearby structures, and the environment. Leakage surveys are also necessary to mitigate the climate change impacts of methane leaks.

Lastly, consistent with the GPAC recommendations, PHMSA adopts the remaining requirements proposed in the NPRM for application to all Type C lines with an outside diameter of greater than 16 inches, and Type C lines with an outside diameter greater than 12.75 inches but not exceeding 16 inches in outer diameter, that are located near buildings intended for human

[77] *See, e.g.,* PHMSA, Interpretation Letter No PI–01–0104, Letter to Richard Motsinger (Apr. 3, 2001), *https://www.phmsa.dot.gov/regulations/title49/interp/PI-01-0104.*

occupancy or other impacted sites. For example, MAOP determinations will also be required for Type C gathering lines with an outside diameter greater than 16 inches, and Type C lines larger than 12.75 inches in outside diameter up to and including 16 inches in outside diameter that are located in a potential impact circle containing a building intended for human occupancy or other impacted sites. The amendments proposed in the NPRM to the tables in § 192.619(a)(3) that would give existing Type C gathering lines the option of establishing an MAOP based on historical operating pressure have been incorporated into the final rule. Therefore, newly regulated Type C lines now will have the option of establishing MAOP using the highest actual operating pressure to which the segment was subjected during the five years (60 months) preceding the effective date of the rule, or five years (60 months) before first becoming subject to the rule, whichever is later.

However, PHMSA supports the GPAC recommendation to allow operators of Type C gas gathering lines to establish MAOP using alternative methods pursuant to the notification process set forth in § 192.18 and the requirements of § 192.619(c)(2). PHMSA is persuaded that allowing alternative methods with PHMSA approval under § 192.18 for establishing the MAOP of a previously unregulated Type C gas gathering line existing on or before the effective date of the rule is appropriate. Such operators were not previously required to make and maintain records of MAOP, pressure tests, or operating pressure and may not have traceable, verifiable, and complete records necessary to calculate an MAOP using the lowest of each of the methods listed in § 192.619. This final rule includes a new § 192.619(c)(2) and conforming changes to § 192.18 to allow an operator of an existing Type C regulated gathering lines based on available records. Under this process, the operator would propose an MAOP based on the information available about the pipeline, such as actual highest operating pressure, operational and maintenance history, pressure test records, and information about the design and material properties of the pipeline. The new paragraph specifies the minimum information required to be submitted to PHMSA in the notification. The ''no objection'' process in § 192.18 requires PHMSA to respond within 90 days. If, after 90 days, PHMSA has not responded to the notification, the operator would be allowed to use the ''other technology'' method to establish MAOP. This approach is not permitted for natural gas pipeline facilities other than Type C regulated gathering lines.

The risk-based application of each of these Type C requirements is based on the operational and functional characteristics of those lines and strikes an appropriate balance between the need to protect people and the environment from the risks associated with large-diameter, high-pressure gathering lines and the need to exercise caution imposing regulatory burdens before more detailed information can be collected. The most substantive requirements apply to all Type C gathering lines with outer diameter of more than 16 inches and Type C gathering lines larger than 12.75 inches up through and including 16 inches that could directly affect homes, businesses, and other building intended for human occupancy. This approach focuses more stringent compliance measures on gas gathering lines that pose the most significant potential hazard to people and the environment. The requirements that remain for Type C gathering lines with an outside diameter of 12.75 inches or less include initial design, construction and testing requirements, leakage surveys emergency planning, damage prevention, and corrosion control. While the GPAC recommended PHMSA consider applying leakage survey requirements to all Type C gathering lines, PHMSA has concluded that more detailed information on the extent and safety performance of such pipelines is needed to justify applying those requirements for Type C lines 16 inches in outside diameter and smaller that do not have a building intended for human occupancy within the PIR. However, as discussed at the GPAC meeting and in this final rule, PHMSA will use the data collected from the new reporting requirements to evaluate continuously PHMSA's oversight of gas gathering lines and determine if additional requirements are appropriate in the future.

There is no potential impact circle or class-location unit-based exception for Type C gathering lines larger than 16 inches in outside diameter. PHMSA considered alternatives raised in the GPAC discussions and public comments, such as having no limit to the potential impact circle exception or limiting it to an outside diameter of 24 inches. After considering these factors and the revised RIA, PHMSA ultimately determined that the 16-inch limit for the PIR exception initially presented to the committee was appropriate. PHMSA notes that API and other industry commenters on the NPRM suggested 16 inches or greater, without a PIR exception, as an alternative definition for Type C. Many of the Type C requirements applicable to larger pipelines relate to initial design, construction, and corrosion control issues, and it is important for such pipelines to be properly constructed, tested, coated, and have cathodic protection applied before new homes and other buildings intended for human occupancy are built nearby in the future—because such measures reduce associated safety risks. Additionally, the volume of a pipeline and the energy released during a rupture increase exponentially as pipe diameter increases. A rupture on a larger-diameter pipeline, all else being equal, is therefore more likely to have consequences other than direct damage to structures. These include externalized economic disruptions to downstream users and environmental consequences such as methane emissions and ecological damage. These external consequences can be significant even if the potential impact radius of a pipeline segment is smaller than the width of a gas transmission class location unit (660 ft.).

The NPRM's other proposed changes, including revisions to § 192.619(a)(4) and 192.619(e), only apply to gas transmission lines. In the Gas Transmission Final Rule, PHMSA clarified which new regulatory requirements from the NPRM apply only to gas transmission lines by including exceptions to those requirements for Type A and Type B gathering lines § 192.9(c). In this final rule, Type C lines are also exempt from these requirements. Several other regulatory changes proposed in the NPRM, specifically the proposed repair criteria, were intended to apply solely to gas transmission lines. PHMSA expects to clarify the applicability of those requirements when the final rule addressing the repair criteria for gas transmission lines is published under RIN 2137–AF39.

In response to comments and additional analysis, PHMSA has also updated the RIA. The revisions and clarifications described above reduce the cost of the requirements in § 192.9. Specifically, the most significant of the proposed requirements will now apply only to large-diameter pipelines and certain smaller-diameter pipelines that are located within a potential impact circle containing a building intended for human occupancy or other impacted sites. Additionally, clarifying that the recordkeeping, material verification, and MAOP reconfirmation requirements proposed in the NPRM were not intended to apply to gathering or distribution lines addresses a large share

of the cost concerns raised in the comments.

IV. Section-by-Section Analysis

§ 191.1 Scope

Part 191 prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipelines. Section 191.1 identifies the scope of applicability of the reporting requirements. PHMSA is revising § 191.1(a) to more clearly state that part 191 applies to offshore and onshore gas gathering not excepted by § 191.1(b). This change is intended to define the existing scope of part 191 to offshore gas gathering lines and the revised applicability to onshore gas gathering lines in plain language. PHMSA is revising § 191.1(b) to remove the exception to part 191 in § 191.1(b)(4) for unregulated, onshore gas gathering lines, including gathering lines that operate at less than 0 psig or are located within the inlets of the Gulf of Mexico. Incident Reports and Annual Reports will now be required for all onshore gas gathering lines, including Type R gathering lines. The expanded reporting requirements for previously unregulated gas gathering lines will provide data for monitoring the safety performance of these pipelines and a sound basis for evaluating if future regulatory changes are needed. However, this final rule excepts Type R gas gathering lines from requirements for OPID validation in § 191.22(b), notifications in § 191.22(c), and safety-related condition reports in § 191.23. Operators must still update their OPID information (*e.g.,* change in primary entity, change in name) before submitting an incident or annual report if a change has occurred.

§ 191.3 Definitions

PHMSA is adding definitions for ''regulated onshore gathering'' and ''reporting-regulated gathering.'' The term ''regulated onshore gathering'' is defined as a Type A, Type B, or Type C gas gathering line as determined in accordance with § 192.8. The term ''reporting-regulated gathering'' is defined as an onshore gathering pipeline other than a regulated onshore gathering pipeline. These pipelines have been designated as ''Type R'' gathering lines in § 192.8 but are not regulated under that part.

§ 191.15 Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities: Incident Report

This revision requires operators of Type R gathering pipelines to submit incident reports using DOT Form PHMSA F 7100.2–2. Regulated gathering lines, including Type C gathering lines, must continue to submit reports using DOT Form PHMSA F 7100.2.

For Type R gathering lines, an incident report is required for any event meeting the definition of an incident that occurs after the effective date of the rule. Operators are not required to categorize and report retroactively events which occurred before the effective date of the rule. The form excludes information related to part 192 requirements that do not apply.

§ 191.17 Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities: Annual Report

This section prescribes requirements for submitting annual reports. This final rule adds a paragraph (a)(2) that specifies the annual reporting requirements for operators of Type R gathering lines. Such operators must complete and submit DOT Form PHMSA F 7100.2–3. The first report is due no later than March 15, 2023 for the 2022 reporting year. The form instructions address how to report data attributes that are unknown.

§ 191.23 Reporting Safety-Related Conditions

This section specifies requirements for submitting safety-related conditions. In this final rule, paragraph (b)(1) is revised to except Type R gathering lines from safety-related condition reporting requirements in §§ 191.23 and 191.25.

§ 191.29 National Pipeline Mapping System

Section 191.29 specifies requirements for participation in the National Pipeline Mapping System (NPMS). Section 60132 of the Federal Pipeline Safety Law requires operators of a pipeline facilities excluding distribution and gathering lines to provide information to be included in the NPMS. In response to comments, the final rule clarifies that the requirements in § 191.29 do not apply to gas gathering lines. Although § 191.29(a) states the requirement applies only to operators of gas transmission lines and liquefied natural gas (LNG) facilities, the final rule makes the exclusion of gas gathering lines, including regulated onshore gas gathering lines, more explicit.

§ 192.3 Definitions

Section 192.3 defines certain terms used in part 192. The final rule adds a definition for ''composite materials.'' The term ''composite materials'' means the materials used to make pipes or components manufactured with a combination of either steel and/or plastic and a reinforcing material to maintain their circumferential or longitudinal strength. This definition is added to describe the process for notifying PHMSA prior to the use of composite materials on new, replaced, relocated, or otherwise changed Type C gathering lines in § 192.9. This definition alone does not authorize the use of composite pipe or materials under this part.

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

Section 192.8 describes how onshore pipelines and segments are determined to be onshore gathering lines and regulated onshore gathering lines. The definition of regulated onshore gathering line has been redesignated as paragraph (c). The final rule adds a new paragraph (b) to specify that gas gathering line must maintain records documenting the methodology used to determine the beginning and endpoints of segments determined to be gas gathering lines as determined in accordance with part 192. This final rule specifies that these records must be established within 1 year of the effective date of the rule, or within 1 year of pipeline installation, whichever is later. These records include the API RP 80 definitions and methods used to define the beginning and endpoints and where those points are located (*e.g.,* mile markers, address, or coordinates). Operators must maintain these records for the life of the pipeline, meaning until the pipeline is removed from the ground or permanently abandoned in place in accordance with § 192.727. An operator may request an alternative compliance deadline with a notification to PHMSA submitted in accordance with § 192.18 if the standard compliance deadline is impracticable. This notification must include a description of the affected facilities and operating environment, the justification for an alternative compliance deadline, and the operator's proposed alternative deadline. This notification must be submitted to PHMSA no later than 90 days prior to the standard compliance deadline in § 192.8(b)(1). The operator

may proceed with their proposed alternative deadline if they receive a no objection letter from PHMSA or if PHMSA has not replied within 90 days of submitting the notification.

The final rule also revises § 192.8(a)(5) to address the use of the incidental gathering concept described in API RP 80. For new, replaced, relocated, or otherwise changed gas gathering lines installed after the effective date of this final rule, the ''incidental gathering'' concept, as described in section 2.2.1.2.6 of API RP 80, may not be used if the ''incidental'' endpoint in paragraph 2.2(a)(1)(E) of API RP 80 is 10 miles or more from the furthermost downstream point where a gathering line end as determined in accordance with paragraphs 2.2 (a)(1)(A) through (a)(1)(D) of API RP 80 and § 192.8 (*e.g.* processing facilities, compressor stations, points of comingling). A new, replaced, relocated, or otherwise changed pipeline that is designated as an ''incidental gathering'' pipeline in API RP 80 but is 10 miles or more in length will be considered a transmission pipeline subject to all applicable portions of parts 191 and 192. Incidental gathering lines existing on or before the effective date of the rule may continue to operate as a gathering line, regardless of length.

One major aspect of this final rule is to identify a new category of regulated onshore gas gathering lines, designated as Type C lines in § 192.8. As discussed previously, a Type C regulated onshore gathering line is defined as any onshore gathering line that is 8.625 inches or larger in outside diameter, is located in a Class 1 location, and meets one of the following criteria, as applicable.

- Metallic pipe and the MAOP produces a hoop stress of 20 percent or more of SMYS;
- Metallic pipe and, if the stress level is unknown, the MAOP is more than 125 psig (862 kPa); or
- Non-metallic and the MAOP is more than 125 psig (862 kPa).

The minimum safety standards applicable to Type C gathering lines are specified in the revisions to § 192.9. The final rule adds the new Type C category to the table in § 192.8(b)(2). The purpose of adding this new category of regulated gas gathering lines is to ensure that operators of larger-diameter, higher-pressure gas gathering lines in Class 1 locations follow a basic set of requirements targeting known threats to public safety and pipeline integrity such as excavation damage, corrosion, and construction defects.

§ 192.9 What requirements apply to gathering lines?

This final rule codifies the minimum safety standards for Type C regulated gas gathering lines. The requirements for Type C gathering lines in this final rule are broken down as follows:

Type C requirements for pipelines with outside diameter of 8.625 inches and greater:

- Design, installation, construction, and initial inspection and testing per transmission line requirements in part 192 for lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13;
- Corrosion control (part 192, subpart I);
- Damage prevention program (§ 192.614);
- Emergency plans (§ 192.615);
- Public awareness (§ 192.616);
- Line markers (§ 192.707); and
- Leakage surveys (§ 192.706).

Additional Type C requirements for pipelines with an outside diameter of 12.75 inches and greater:

- Applicable requirements of part 192 for plastic pipe and components; and
- Establish MAOP (§ 192.619).

The final rule adds § 192.9(f), which creates an exception from certain part 192 requirements if a Type C gathering line has a diameter of 16 inches or less and is not located near local communities as determined by one of the following methods:

Method 1. Potential Impact Circle. The segment is not located within a potential impact circle as defined in § 192.903 containing a building intended for human occupancy or other impacted site. This is the same method used to determine HCAs in the gas transmission integrity management regulations. Note that similar to the method for identifying HCAs, any point on a pipeline located *within* any potential impact circle containing a building intended for human occupancy or other impacted site may not apply the exception even if a potential impact circle drawn from that point does not contain such a location itself (Refer to Figure E.I.A. in appendix E to part 192).

The formula for calculating a potential impact radius is defined in § 192.903. PHMSA notes that this formula requires knowledge of the MAOP and nominal diameter of the pipeline. If the segment does not have an MAOP established in accordance with § 192.619, or if the diameter is unknown, the operator must use method 2 or not apply the exception and comply with the Type C requirements that are applicable based on the diameter of the pipeline. Additionally, operators must use a factor of 0.73 rather than the dry gas factor of 0.69 used in the integrity management regulations. The increased factor accounts for the potentially higher combustion energy of unprocessed natural gas, which may contain varying amounts of other combustible hydrocarbons.

Method 2: Class Location Unit. This analysis is similar to Method 1. However instead of calculating a potential impact circle, the class location unit as defined in § 192.5(a)(1) is used. This is the ''sliding mile'' or ''continuous-mile'' analysis used for class location determination. A class location unit is 1 mile in length and extends 220 yards on either side of the centerline of a pipeline. PHMSA notes that this uses the same ''sliding mile'' approach used for determining class location rather than static mile-long increments stacked end-over-end. The class-location unit moves along the pipeline, and if the sliding mile contains a building intended for human occupancy or other impacted site at any point during the mile's movement, then the exception in paragraph (f) does not apply for the entire mile of pipeline contained within the sliding mile. This method does not require knowledge of the pipeline's MAOP.

For the purposes of applying this exception, ''building intended for human occupancy'' or ''other impacted site'' is defined in § 192.9(f)(4) to mean any of the following:

- One or more buildings that may be occupied by humans, including homes, office buildings factories, outside recreation areas, and plant facilities.
- A small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive). This has the same meaning and interpretation as the Class 3 criterion in § 192.5(b)(3)(ii); or
- Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes. This has the same meaning and interpretation of section (1)(ii) of the ''moderate consequence area'' definition in § 192.3.

The table below summarizes the applicability of the Type C requirements based on the size and location of a given segment.

Outside diameter	*Not* located near a building intended for human occupancy or other impacted site (§ 192.9(f))	Located near a building intended for human occupancy or other impacted site (§ 192.9(f))
Greater than or equal to 8.625 inches up to and including 12.75 inches.	—Design, Construction, Initial Testing (new/replaced/relocated/changed lines). —Damage Prevention. —Emergency plans.	—Design, Construction, Initial Testing (new/replaced/relocated/changed lines). —Corrosion Control. —Damage Prevention. —Emergency Plans. —Line Markers. —Public Awareness. —Leakage Surveys.
Greater than 12.75 inches up to and including 16 inches.	—Design, Construction, Initial Testing (new/replaced/relocated/changed lines). —Damage Prevention. —Emergency Plans.	All Type C Requirements.
Greater than 16 inches	All Type C Requirements	All Type C Requirements.

Section 60104(b) of the Pipeline Safety Acts exempts new design, installation, construction, initial inspection, and initial testing standards from applying to gathering lines that existed before the effective date of this final rule. In other words, if a previously unregulated gas gathering line becomes regulated by operation of this final rule (and is not itself replaced, relocated, or otherwise changed after the compliance date in § 192.13), the operator is not required to bring retroactively that pipeline facility into compliance with the new design, installation, construction, initial inspection, and initial testing requirements.

The rule also adds an exception in § 192.9(f)(3) to these requirements for segments shorter than 40 feet [78] that are installed, relocated, or changed on Type C gathering lines that were installed before the effective date of the rule. Regulations in part 192 that do not pertain to design, installation, construction, initial installation, or initial testing may apply to the segment regardless of the date of installation.

In § 192.9(g)(4), existing gathering lines that become classified as Type C regulated gathering lines due to the publication of this final rule have a 1-year compliance deadline to meet the applicable requirements in this section. An operator may request an alternative compliance deadline with a notification to PHMSA submitted in accordance with § 192.18 if the standard compliance deadline is impracticable. This notification must include a description of the affected facilities and operating environment and, for each requirement that requires an alternative compliance deadline: The justification for an alternative compliance deadline, and the operator's proposed alternative deadline. The notification must also include a description of actions the operator will take to ensure the safety of the affected facilities in the interim. This notification must be submitted no later than 90 days prior to the standard compliance deadline. The operator may proceed with their proposed alternative deadline if they receive a no objection letter from PHMSA or if PHMSA has not replied within 90 days of submitting the notification.

In § 192.9(g)(5), operators of gathering lines that become classified as Type C regulated gathering lines in the future due to an increase in MAOP, a change in dwelling density, or a change in class location have a 1-year compliance deadline to meet the requirements of this section. Similarly, an operator of a Type C gathering line that becomes subject to additional Type C requirements in the future, for example when a change in dwelling density or increased MAOP causes the exceptions in paragraph (f) to no longer apply, has a 1-year compliance deadline to meet those additional requirements. Conforming changes were made to paragraphs (g)(2) and (3) to clarify that the existing implementation deadlines now apply only to Type A and Type B regulated gathering lines.

The final rule also adds a new paragraph (h) to clarify that operators may install or replace pipe or components made of composite materials that are not otherwise authorized in part 192 on Type C gathering lines upon submittal of a notification to PHMSA pursuant to § 192.18, unless PHMSA issues an objection letter to the operator's notification. Under the § 192.18 notification process, PHMSA will evaluate the operator's proposed operation and maintenance procedures, which includes the operator's proposed remediation methods and procedures for identifying defects and determining the safe operating pressures of composite pipe when defects are found. PHMSA will not approve notifications that are not consistent with pipeline safety. A rejection under § 192.18 will not foreclose an operator's ability to seek a special permit in accordance with § 190.341.

Operators may continue to operate gathering lines containing composite pipe or materials existing on or before the effective date of the rule without notification to PHMSA. However, operators of Type C pipelines must comply with all other applicable Type C requirements once the final rule becomes effective. Additionally, per new § 192.9(e)(1)(i), notification is not required for replacements, relocations, or changes of composite pipe segments 40 feet or less in length on pipelines that were installed before the effective date of the rule. Replacements using composite materials on Type C gathering lines, including composite materials installed per a notification, require notification to PHMSA regardless of length. Replacing a segment of composite pipe with steel or plastic pipe and components authorized under part 192 does not require notification. The notification requirement does apply to repairs involving replacements, relocations, or significant changes to the pipe. If an operator discovers a condition that requires immediate replacement, operators should describe all urgent conditions in their notification to PHMSA, request an emergency special permit under § 190.341, or conduct the repair using materials authorized under part 192, such as steel.

§ 192.13 What general requirements apply to pipelines regulated under this part?

This is a conforming change that repeats the compliance deadlines for Type C lines in § 192.8 and clarifies that the previously existing compliance deadlines for regulated gas gathering lines in that section continue to apply

[78] A single length of pipe is typically 40 feet in length.

to Type A and Type B regulated gathering lines.

§ 192.18 How To Notify PHMSA

This is a conforming change in the final rule to allow the use of the notification procedures in this section to comply with §§ 192.8(b) and (g)(4), 192.9(h), and 192.619(c)(2).

§ 192.150 Passage of Internal Inspection Devices

Currently, this section provides that Type A regulated gathering lines are exempt from the requirement that new gas transmission lines be able to accommodate the passage of instrumented internal inspection devices. This amendment clarifies that lower-risk Type B and Type C lines are also exempt.

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

This section of the final rule documents conforming changes to address the applicability of part 192, subpart I, to unregulated gathering lines that become Type C onshore regulated gathering lines. Specifically, it covers previously unregulated gathering lines that become regulated by operation of this final rule. Additionally, it covers previously unregulated gathering lines that become subject to Type C corrosion control requirements in the future due to a change in MAOP or the presence of a building intended for human occupancy or other impacted site. Such pipelines are treated as if they were installed before August 1, 1971, for the purposes of subpart I. The final rule also clarifies in paragraph (d) that gathering lines that are subject to subpart I at the time of construction must meet the corrosion control requirements applicable to pipelines installed after July 31, 1971.

§ 192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

This section of the final rule includes conforming changes on the applicability of § 192.619 for determining the MAOP for newly regulated gathering lines, *i.e.,* Type C lines. Additionally, a new paragraph (c)(2) has been added to allow operators of newly regulated Type C gas gathering lines to establish an MAOP using ''other technology'', upon notification to PHMSA in accordance with § 192.18. This process would only be available to segments where the MAOP was established under § 192.619(c) and the operator does not have the requisite operational pressure records because the pipeline was previously unregulated and not required to retain such records. The justification of the proposed MAOP must be reviewed and accepted by a qualified technical subject matter expert. PHMSA expects a qualified subject matter expert to be an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. The operator must be able to document that the individual is appropriately knowledgeable and experienced in the subject being assessed.

V. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 80 standards and specifications developed and published by standard development organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices. Sometimes multiple editions are published in a given year.

The National Technology Transfer and Advancement Act of 1995 (NTTAA, Pub. L. 104–113) directs Federal agencies to use standards developed by voluntary consensus standards bodies in lieu of government-written standards whenever possible. Voluntary consensus standards bodies develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, OMB issued Circular A–119 to implement section 12(d) of the NTTAA relative to the utilization of consensus technical standards by Federal agencies.[79] This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in the NTTAA.

Accordingly, PHMSA has the responsibility for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to the Federal Pipeline Safety Regulations. Revisions to materials incorporated by reference in the Federal Pipeline Safety Regulations are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

Pursuant to 49 U.S.C. 60102(p), PHMSA may not issue amendments to the Federal Pipeline Safety Regulations that incorporate by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge. Further, the Office of the Federal Register issued a rulemaking on November 7, 2014, revising 1 CFR 51.5(b) to require that agencies detail in the preamble of a final rule how the materials being incorporated by reference are reasonably available to interested parties, and how interested parties can obtain those materials.[80]

The only standard incorporated by reference in the final rule is API RP 80. Free, online, read-only access to API RP 80 is available on the API website (*http://publications.api.org/AccessToDocuments.aspx;* navigate to the ''Exploration and Production'' category). Members of the public interested in obtaining API RP 80 can contact API using the contact information in this final rule's revisions to the regulatory text at § 192.7. In addition, PHMSA will provide individual members of the public temporary access to this or any other standard that is incorporated by reference in the Federal Pipeline Safety Regulations. Requests for access can be sent to the following email address: *phmsaphpstandards@dot.gov.*

VI. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of Federal Pipeline Safety Law. Section 60101(b) authorizes the Secretary of Transportation to prescribe standards defining the term ''gathering line'' that account for the functional and operational characteristics of a pipeline. That section also authorizes the Secretary to prescribe standards defining the term ''regulated gathering line,'' which must consider factors such as location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas. In addition, 49 U.S.C. 60102 authorizes the Secretary to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. Further, 49 U.S.C. 60117(b)(2) authorizes the Secretary to require owners and operators of gathering lines to submit information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines. The

[79] 81 FR 4673 (Jan. 27, 2016).

[80] Incorporation by Reference, 79 FR 66278.

Secretary delegated his authority to the PHMSA Administrator under 49 CFR 1.97.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866 (''Regulatory Planning and Review'') [81] requires that agencies ''should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.'' Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, Executive Order 12866 requires that ''agencies should select those [regulatory] approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.'' Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts.

Executive Order 12866 and DOT Order 2100.6A require that PHMSA submit ''significant regulatory actions'' to the Office of Management and Budget (OMB) for review. This final rule has been determined to be significant under section 3(f) of Executive Order 12866 and was reviewed by OMB. It is also considered significant under DOT Order 2100.6. The Office of Information and Regulatory Affairs (OIRA) has not designated this rule as a ''major rule'' as defined by the Congressional Review Act (5 U.S.C. 801 *et seq.*).

Executive Order 12866 and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which reinforces requirements for notice and comment in the Administrative Procedure Act (APA, 5 U.S.C. 551 *et seq.*). In accord with the requirement, PHMSA sought public comment on the proposals in the NPRM (including preliminary cost and cost savings analyses pertaining to those proposals), as well as any information that could assist in evaluating the benefits and costs of this rulemaking. Those comments are addressed, and additional discussion about the economic impacts of the final rule are provided, within the final regulatory impact analysis (RIA) posted in the docket.

PHMSA expects benefits of the final rule to consist of improved safety and avoided environmental harms (including greenhouse gas emissions) from reduction of risk of failures of onshore natural gas gathering lines due to improved leak detections and subsequent repairs. The expected benefits will depend on the degree to which compliance actions result in additional safety measures, relative to the baseline, and the effectiveness of these measures in preventing or mitigating future pipeline failures. PHMSA estimates annualized costs of $13.7 million per year using a 7 percent discount rate. The costs for compliance with annual reporting and, for Type C gathering lines, compliance with part 192 are expected to be higher in the initial compliance period, as operators will incur one-time costs to achieve compliance in the years leading up to the compliance deadline. Thereafter recurring costs are expected to be lower. For more information, please see the RIA posted in the rulemaking docket.

C. Environmental Justice

DOT Order 5610.2C and Executive Orders 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[82] 13985 (''Advancing Racial Equity and Support for Underserved Communities Through the Federal Government''),[83] 13990 (''Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis''),[84] and 14008 (''Tackling the Climate Crisis at Home and Abroad'') [85] require DOT agencies to achieve environmental justice as part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects, including interrelated social and economic effects, of their programs, policies, and activities on minority populations, low-income populations, and other disadvantaged communities.

PHMSA has evaluated this final rule under DOT Order 5610.2C and the Executive orders listed above and has determined it would not cause disproportionately high and adverse human health and environmental effects on minority populations, low-income populations, or other underserved and disadvantaged communities. The rulemaking is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to adversely impact any particular population, region, or community. And insofar as PHMSA expects the rulemaking would reduce the safety and environmental risks associated with onshore natural gas gathering lines, many of which are located in the vicinity of environmental justice communities,[86] PHMSA does not expect the regulatory amendments introduced by this final rule would entail disproportionately high adverse risks for minority populations, low-income populations, or other underserved and other disadvantaged communities in the vicinity of those pipelines. Lastly, as explained in final environmental assessment (EA), PHMSA expects that the regulatory amendments in this final rule will yield greenhouse gas emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority, low-income, underserved, and other disadvantaged populations and communities.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA, 5 U.S.C. 601 *et seq.*) requires Federal regulatory agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the APA unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. This final rule was developed in accordance with Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'') [87] to promote compliance with the RFA and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA does not have access to firm-level data on gathering line operators that are not currently regulated under part 191 or 192. However, based on data on regulated gathering line operators produced by Dun and Bradstreet, approximately 40 percent of currently regulated gathering line operators are identified as small entities, and those entities operate approximately 24 percent of onshore regulated gas gathering line mileage. Therefore, a

[81] 58 FR 51375 (Oct. 4, 1993).

[82] 59 FR 7629 (Feb. 16, 1994).

[83] 86 FR 7009 (Jan. 20, 2021).

[84] 86 FR 7037 (Jan. 20, 2021).

[85] 86 FR 7619 (Feb. 1, 2021).

[86] *See* Ryan Emmanuel, et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5:6 GeoHealth (June 2021), *https://agupubs.onlinelibrary.wiley.com/toc/24711403/2021/5/6* (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

[87] 67 FR 53461 (Aug. 16, 2002).

significant share of affected entities can be classified as small entities. However, PHMSA expects the magnitude of the economic impact on those entities to be limited, as the annualized costs of the final rule represent only approximately 0.1 percent of annual industry revenues for the entire crude oil transportation industry (NAICS code 486110), illustrating the minor financial impact on firms operating within this space. PHMSA has prepared a FRFA, available in the docket for the rulemaking, in which PHMSA certifies that the rule will not have a significant impact on a substantial number of small entities.

E. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this final rule in accordance with the principles and criteria in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'') [88] and DOT Order 5301.1 (''Department of Transportation Programs, Polices, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Executive Order 13175 requires agencies to assure meaningful and timely input from Tribal government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities or the relationship and distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the rulemaking and determined that it would not significantly or uniquely affect Tribal communities or Indian Tribal governments. The rulemaking's regulatory amendments are facially neutral and would have broad, national scope; PHMSA, therefore, does not expect this rulemaking to significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or mandate Tribal action. And insofar as PHMSA expects the rulemaking will improve natural gas gathering line safety and reduce environmental risks, PHMSA does not expect it would entail disproportionately high adverse risks for Tribal communities. PHMSA also received no comments alleging ''substantial direct compliance costs'' or ''substantial direct effects'' on Tribal communities and Governments. For these reasons, PHMSA has determined the funding and consultation requirements of Executive Order 13175 and DOT Order 5301.1 do not apply.

F. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. PHMSA expects this final rule to impact the information collections described below.

PHMSA will submit an information collection revision request to OMB for approval based on the requirements in this final rule. The information collections are contained in the pipeline safety regulations, 49 CFR parts 190 through 199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burdens for the following information collections are estimated to be revised as follows:

1. *Title:* Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 01/31/2023.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. This mandatory information collection request would require owners and/or operators of gas pipeline systems to make and maintain records in accordance with the requirements prescribed in 49 CFR part 192 and to provide information to the Secretary of Transportation at the Secretary's request. Certain records are maintained for a specific length of time while others are required to be maintained for the life of the pipeline. PHMSA uses these records to verify compliance with regulated safety standards and to inform the agency on possible safety risks.

Based on the provisions in the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, PHMSA estimates that 370 new Type C gas gathering pipeline operators ~ (91,000 Type C miles w/o prior regulation) will be subject to these requirements. PHMSA estimates that it will take these 370 operators 6 hours to create and maintain records associated with 49 CFR 192.9 requirements. Therefore, PHMSA expects to add 370 responses and 2,220 hours to this information collection as a result of the provisions in this final rule.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,861,842.

Total Annual Burden Hours: 1,677,030.

Frequency of Collection: On occasion.

2. *Title:* Annual and Incident Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 10/31/2024.

Abstract: This mandatory information collection covers the collection of annual and immediate notice of incident report data from Gas pipeline operators. As a result of the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, all gas gathering operators will become subject to incident and annual reporting requirements. PHMSA is revising this information collection to account for the new addition to the reporting community. PHMSA will require 500 currently unregulated gas gathering line operators (370 Type C operators and 130 Type R operators) to complete and submit annual reports each year. Type C operators will submit annual report data on DOT Form PHMS F7 100.2–1. The estimated burden for submitting this form is 47 hours per report. Type R operators will submit annual report data on the new DOT Form PHMSA F7 100.2–3. The estimated burden for submitting this form is 21 hours per report. These changes will result in an overall annual burden increase of 20,120 hours (17,390 hours annually for Type C operators and 2,730 hours annually for Type R operators) for this information collection.

Gas Gathering operators will also be required to make immediate telephonic notification of incidents, should they occur. PHMSA expects that these previously unregulated operators will make approximately 85 telephonic notifications of incidents per year. PHMSA estimates that it takes 30 minutes to complete a telephonic notification. As such, the estimated burden for gas gathering operators to make immediate notification of incidents is approximately 43 hours.

As a result of the provisions mentioned above, the burden for this information collection will increase by 585 new responses and 10,543 burden hours.

Affected Public: Natural Gas Pipeline Operators.

[88] 65 FR 67249 (Nov. 6, 2000).

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 2,832.

Total Annual Burden Hours: 91,964.

Frequency of Collection: Annually and on occasion.

3. *Title:* Incident Reports for Natural Gas Pipeline Operators.

OMB Control Number: 2137–0635.

Current Expiration Date: 10/31/2024.

Abstract: Operators of natural gas pipelines and LNG facilities are required to report incidents, on occasion, to PHMSA per the requirements in 49 CFR part 191. This mandatory information collection covers the collection of incident report data from natural gas pipeline operators. The reports contained within this information collection support the Department of Transportation's strategic goal of safety. This information is an essential part of PHMSA's overall effort to minimize natural gas transmission, gathering, and distribution pipeline failures. Due to the provisions contained within the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, operators will be required to submit reports of incidents that occur on previously unregulated gas gathering systems.

Based on PHMSA's estimate of the mileage of Type C and Type R gas gathering pipelines and the incident rate on Type A and Type B gas gathering pipelines, PHMSA expects to receive approximately 85 incident reports (18 Type C incident reports and 67 Type R incident reports) each year from gas gathering operators. As a result, the burden for this information collection will increase by 85 responses. The burden per incident report is estimated at 12 hours per report. This results in an estimated burden increase of 1,020 hours (216 hours for Type C and 804 hours for Type R) per year.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 344.

Total Annual Burden Hours: 4,128.

Frequency of Collection: On occasion.

4. *Title:* National Registry of Pipeline and LNG Operators.

OMB Control Number: 2137–0627.

Current Expiration Date: 01/31/2023.

Abstract: The National Registry of Pipeline and LNG Operators serves as the storehouse for the reporting requirements for an operator regulated or subject to reporting requirements under 49 CFR part 192, 193, or 195. This mandatory information collection would require jurisdictional pipeline operators to submit the required data to register with the National Registry of Pipeline and LNG Operators and notify PHMSA when they experience significant asset changes, including new construction, that affect PHMSA's ability to accurately monitor and assess pipeline safety performance. Certain types of changes to, or within, an operator's facilities or pipeline network represent potential safety-altering activities for which PHMSA may need to inspect, investigate, or otherwise oversee to ensure that any public safety concerns are adequately and proactively addressed. The forms for assigning and maintaining Operator Identification (OPID) information are the Operator Assignment Request Form (PHMSA F 1000.1) and Operator Registry Notification Form (PHMSA F 1000.2). The purpose of this information collection is to maintain an accurate assessment of the Nation's pipeline infrastructure and to be kept abreast of conditions that could potentially compromise the safety and economic viability of the U.S. pipeline system.

Due to the provisions contained within the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, gas gathering pipeline operators must now request OPIDs due to the repeal of the reporting exception for gathering pipelines other than regulated gathering lines as determined in § 192.8. PHMSA plans to revise the OPID Registry form and instructions to account for this addition to the reporting community. PHMSA believes that many operators of previously unregulated gathering lines are already submitting annual report data for regulated gas gathering lines and may already have an OPID. As such, PHMSA expects to receive approximately 13 new OPID requests. PHMSA also requires these newly regulated operators to submit notifications to PHMSA in certain instances. PHMSA similarly expects to receive approximately 13 new notifications from gas gathering pipeline operators. These additions will result in an increase to the burden of this information collection by 26 responses and 26 burden hours.

Affected Public: Operators of Natural Gas, Hazardous Liquid, and Liquefied Natural Gas pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 744.

Total Annual Burden Hours: 744.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, Telephone (202) 366–1246.

G. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (UMRA, 2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate of $100 million or more (in 1996 dollars) in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate. PHMSA prepared a final RIA and determined that this final rule does not impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more (in 1996 dollars) in any one year. A copy of the RIA is available for review in the docket of this rulemaking.

H. National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA, 42 U.S.C. 4321 *et seq.*) requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA has completed its NEPA analysis. Based on the environmental assessment, PHMSA determined that an environmental impact statement is not required for this rulemaking because it will not have a significant impact on the human environment. The final EA and Finding of No Significant Impact have been placed into the docket addressing the comments received.

I. Executive Order 13132: Federalism

PHMSA analyzed this final rule in accordance with Executive Order 13132 (''Federalism'').[89] Executive Order 13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have a substantial direct effect on State and local governments, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. The final rule exercises PHMSA's existing authority to require operators of gas gathering line to submit safety data (49 U.S.C. 60117(b)(2)) and to define and establish safety standards for regulated gas gathering lines (49 U.S.C. 60101(b)). PHMSA determined the final rule's changes to the requirements for onshore gas gathering lines were necessary based on the results of PHMSA's review of existing gas gathering requirements performed pursuant to section 21 of the 2011 Pipeline Safety Act.

Section 60104(c) of Federal Pipeline Safety Law prohibits certain State safety regulation of interstate pipelines. Under the pipeline safety laws, States that have submitted a current certification under section 60105(a) can augment Federal pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate.

In this instance, the preemptive effect of the final rule is limited to the minimum level necessary to achieve the objectives of the Federal Pipeline Safety Law under which the final rule is promulgated. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

J. Executive Order 13211: Significant Energy Actions

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') [90] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Executive Order 13211 defines a ''significant energy action'' as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation that (1)(i) is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy (including a shortfall in supply, price increases, and increased use of foreign supplies); or (2) is designated by the Administrator of the OIRA as a significant energy action.

This final rule is a significant action under Executive Order 12866; however, it is expected to have an annual effect on the economy of less than $100 million. Further, this final rule is not likely to have a significant adverse effect on supply, distribution, or energy use, as further discussed in the RIA. Further, OIRA has not designated this final rule as a significant energy action.

K. Privacy Act Statement

In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its rulemaking process. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *www.dot.gov/privacy.*

L. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN number contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

M. Executive Order 13609 and International Trade Analysis

Executive Order 13609 (''Promoting International Regulatory Cooperation'') [91] requires agencies to consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA participates in the establishment of international standards to protect the safety of the American public. PHMSA has assessed the effects of the rulemaking and determined that it will not cause unnecessary obstacles to foreign trade.

List of Subjects

49 CFR Part 191

MAOP exceedance, Pipeline reporting requirements.

49 CFR Part 192

Incorporation by reference, Integrity assessments, MAOP reconfirmation, Material verification, Pipeline safety, Predicted failure pressure, Reporting and recordkeeping requirements, Risk assessment, Safety devices.

In consideration of the foregoing, PHMSA amends 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. The heading for part 191 is revised to read as set forth above.

■ 3. In § 191.1, paragraphs (a) and (b)(2) and (3) are revised, paragraph (b)(4) is removed, and paragraph (c) is added to read as follows:

[89] 64 FR 43255 (Aug. 10, 1999).

[90] 66 FR 28355 (May 22, 2001).

[91] 77 FR 26413 (May 4, 2012).

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in the United States or Puerto Rico, including underground natural gas storage facilities and pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). This part applies to offshore gathering lines (except as provided in paragraph (b) of this section) and to onshore gathering lines, including Type R gathering lines as determined in § 192.8 of this chapter.

(b) * * *

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9; or

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

(c) Sections 191.22(b) and (c) and 191.23 do not apply to the onshore gathering of gas—

(1) Through a pipeline that operates at less than 0 psig (0 kPa);

(2) Through a pipeline that is not a regulated onshore gathering pipeline; or

(3) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612 of this chapter.

■ 4. In § 191.3, add definitions for ''Regulated onshore gathering'' and ''Reporting-regulated gathering'' in alphabetical order to read as follows:

§ 191.3 Definitions.

* * * * *

Regulated onshore gathering means a Type A, Type B, or Type C gas gathering pipeline system as determined in § 192.8 of this chapter.

Reporting-regulated gathering means a Type R gathering line as determined in § 192.8 of this chapter. A Type R gathering line is subject only to this part.

* * * * *

■ 5. In § 191.15, paragraph (a) is revised to read as follows:

§ 191.15 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

(a) *Pipeline systems*—(1) *Transmission or regulated onshore gathering.* Each operator of a transmission pipeline system or a regulated onshore gathering pipeline system must submit Department of Transportation (DOT) Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5.

(2) *Reporting-regulated gathering.* Each operator of a reporting-regulated gathering pipeline system must submit DOT Form PHMSA F 7100.2–2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 that occurs after May 16, 2022.

* * * * *

■ 6. In § 191.17, paragraph (a) is revised to read as follows:

§ 191.17 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.

(a) *Pipeline systems*—(1) *Transmission or regulated onshore gathering.* Each operator of a transmission or a regulated onshore gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(2) *Type R gathering.* Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2–3. This report must be submitted each year, not later than March 15, for the preceding calendar year.

* * * * *

■ 7. In § 191.23, revise paragraph (b)(1) to read as follows:

§ 191.23 Reporting safety-related conditions.

* * * * *

(b) * * *

(1) Exists on a master meter system, a reporting-regulated gathering pipeline, or a customer-owned service line;

* * * * *

■ 8. In § 191.29, paragraph (c) is added to read as follows:

§ 191.29 National Pipeline Mapping System.

* * * * *

(c) This section does not apply to gathering pipelines.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 9. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

■ 10. In § 192.3, add a definition for ''Composite materials'' in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Composite materials means materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

* * * * *

■ 11. Amend § 192.8 as follows:
■ a. Revise the section heading;
■ b. Add paragraph (a)(5);
■ c. Redesignate paragraph (b) as a paragraph (c);
■ d. Add new paragraph (b); and
■ e. Revise newly redesignated paragraph (c).

The revisions and addition read as follows:

§ 192.8 How are onshore gathering pipelines and regulated onshore gathering pipelines determined?

(a) * * *

(5) For new, replaced, relocated, or otherwise changed gas gathering pipelines installed after May 16, 2022, the endpoint of gathering under sections 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 (incorporated by reference, *see* § 192.7)—also known as ''incidental gathering''—may not be used if the pipeline terminates 10 or more miles downstream from the furthermost downstream endpoint as defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 (incorporated by reference, *see* § 192.7) and this section. If an ''incidental gathering'' pipeline is 10 miles or more in length, the entire portion of the pipeline that is designated as an incidental gathering line under 2.2(a)(1)(E) and 2.2.1.2.6 of

API RP 80 shall be classified as a transmission pipeline subject to all applicable regulations in this chapter for transmission pipelines.

(b) Each operator must determine and maintain for the life of the pipeline records documenting the methodology by which it calculated the beginning and end points of each onshore gathering pipeline it operates, as described in the second column of table 1 to paragraph (c)(2) of this section, by:

(1) November 16, 2022, or before the pipeline is placed into operation, whichever is later; or

(2) An alternative deadline approved by the Pipeline and Hazardous Materials Safety Administration (PHMSA). The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include the following information:

(i) Description of the affected facilities and operating environment;

(ii) Justification for an alternative compliance deadline; and

(iii) Proposed alternative deadline.

(c) For purposes of part 191 of this chapter and § 192.9, the term ''regulated onshore gathering pipeline'' means:

(1) Each Type A, Type B, or Type C onshore gathering pipeline (or segment of onshore gathering pipeline) with a feature described in the second column of table 1 to paragraph (c)(2) of this section that lies in an area described in the third column; and

(2) As applicable, additional lengths of pipeline described in the fourth column to provide a safety buffer:

TABLE 1 TO PARAGRAPH (c)(2)

Type	Feature	Area	Additional safety buffer
A	—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. —If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is more than 125 psig (862 kPa).	Class 2, 3, or 4 location (*see* § 192.5)	None.
B	—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is 125 psig (862 kPa) or less.	*Area 1.* Class 3, or 4 location *Area 2.* An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location; (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	If the gathering pipeline is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2(b) or 2(c) qualifies a pipeline as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.
C	Outside diameter greater than or equal to 8.625 inches and any of the following: —Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS; —If the stress level is unknown, segment is metallic and the MAOP is more than 125 psig (862 kPa); or —Non-metallic and the MAOP is more than 125 psig (862 kPa).	Class 1 location	None.
R	—All other onshore gathering lines	Class 1 and Class 2 locations	None.

(3) A Type R gathering line is subject to reporting requirements under part 191 of this chapter but is not a regulated onshore gathering line under this part.

■ 12. Amend § 192.9 as follows:

■ a. Revise the section heading;

■ b. Redesignate paragraph (e) as paragraph (g);

■ c. Add a new paragraph (e) and paragraph (f);

■ d. Revise newly redesignated paragraphs (g)(2) and (3);

■ e. Add paragraphs (g)(4) and (5); and

■ f. Add paragraph (h).

The revisions and additions read as follows:

§ 192.9 What requirements apply to gathering pipelines?

* * * * *

(e) *Type C lines.* The requirements for Type C gathering lines are as follows.

(1) An operator of a Type C onshore gathering line with an outside diameter greater than or equal to 8.625 inches must comply with the following requirements:

(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B though G and J of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.205, 192.227(c), 192.285(e), and 192.506 is not required;

(ii) If the pipeline is metallic, control corrosion according to requirements of

subpart I of this part applicable to transmission lines except for § 192.493;

(iii) Carry out a damage prevention program under § 192.614;

(iv) Develop and implement procedures for emergency plans in accordance with § 192.615;

(v) Develop and implement a written public awareness program in accordance with § 192.616;

(vi) Install and maintain line markers according to the requirements for transmission lines in § 192.707; and

(vii) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706 using leak-detection equipment, and promptly repair hazardous leaks in accordance with § 192.703(c).

(2) An operator of a Type C onshore gathering line with an outside diameter greater than 12.75 inches must comply with the requirements in paragraph (e)(1) of this section and the following:

(i) If the pipeline contains plastic pipe, the operator must comply with all applicable requirements of this part for plastic pipe or components. This does not include pipe and components made of composite materials that incorporate plastic in the design; and

(ii) Establish the MAOP of the pipeline under § 192.619(a) or (c) and maintain records used to establish the MAOP for the life of the pipeline.

(f) *Exceptions.* (1) Compliance with paragraphs (e)(1)(ii), (v), (vi), and (vii) and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met:

(i) *Method 1.* The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in § 192.903, except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with paragraph (e)(2)(ii) of this section.

(ii) *Method 2.* The segment is not located within a class location unit (*see* § 192.5) containing a building intended for human occupancy or other impacted site.

(2) Paragraph (e)(1)(i) of this section is not applicable to pipeline segments 40 feet or shorter in length that are replaced, relocated, or changed on a pipeline existing on or before May 16, 2022.

(3) For purposes of this section, the term ''building intended for human occupancy or other impacted site'' means any of the following:

(i) Any building that may be occupied by humans, including homes, office buildings factories, outside recreation areas, plant facilities, etc.;

(ii) A small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive); or

(iii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

(g) * * *

(2) If a Type A or Type B regulated onshore gathering pipeline existing on April 14, 2006, was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the pipeline listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
(i) Control corrosion according to requirements for transmission lines in subpart I of this part	April 15, 2009.
(ii) Carry out a damage prevention program under § 192.614	October 15, 2007.
(iii) Establish MAOP under § 192.619	October 15, 2007.
(iv) Install and maintain line markers under § 192.707	April 15, 2008.
(v) Establish a public education program under § 192.616	April 15, 2008.
(vi) Other provisions of this part as required by paragraph (c) of this section for Type A lines	April 15, 2009.

(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering pipeline to become a Type A or Type B regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the pipeline becomes a regulated onshore gathering pipeline to comply with this section.

(4) If a Type C gathering pipeline existing on or before May 16, 2022, was not previously subject to this part, an operator must comply with the applicable requirements of this section, except for paragraph (h) of this section, on or before:

(i) May 16, 2023; or

(ii) An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include a description of the affected facilities and operating environment, the proposed alternative deadline for each affected requirement, the justification for each alternative compliance deadline, and actions the operator will take to ensure the safety of affected facilities.

(5) If, after May 16, 2022, a change in class location, an increase in dwelling density, or an increase in MAOP causes a pipeline to become a Type C gathering pipeline, or causes a Type C gathering pipeline to become subject to additional Type C requirements (*see* paragraph (f) of this section), the operator has 1 year after the pipeline becomes subject to the additional requirements to comply with this section.

(h) *Composite materials.* Pipe and components made with composite materials not otherwise authorized for use under this part may be used on Type C gathering pipelines if the following requirements are met:

(1) Steel and plastic pipe and components must meet the installation, construction, initial inspection, and initial testing requirements in subparts B though G and J of this part applicable to transmission lines.

(2) Operators must notify PHMSA in accordance with § 192.18 at least 90 days prior to installing new or replacement pipe or components made of composite materials otherwise not authorized for use under this part in a Type C gathering pipeline. The notifications required by this section must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including:

(i) The beginning and end points (stationing by footage and mileage with latitude and longitude coordinates) of the pipeline segment containing composite pipeline material and the counties and States in which it is located;

(ii) A general description of the right-of-way including high consequence areas, as defined in § 192.905;

(iii) Relevant pipeline design and construction information including the year of installation, the specific composite material, diameter, wall thickness, and any manufacturing and construction specifications for the pipeline;

(iv) Relevant operating information, including MAOP, leak and failure history, and the most recent pressure test (identification of the actual pipe tested, minimum and maximum test pressure, duration of test, any leaks and any test logs and charts) or assessment results;

(v) An explanation of the circumstances that the operator believes make the use of composite pipeline material appropriate and how the design, construction, operations, and maintenance will mitigate safety and environmental risks;

(vi) An explanation of procedures and tests that will be conducted periodically over the life of the composite pipeline material to document that its strength is being maintained;

(vii) Operations and maintenance procedures that will be applied to the alternative materials. These include procedures that will be used to evaluate and remediate anomalies and how the operator will determine safe operating pressures for composite pipe when defects are found;

(viii) An explanation of how the use of composite pipeline material would be in the public interest; and

(ix) A certification signed by a vice president (or equivalent or higher officer) of the operator's company that operation of the applicant's pipeline using composite pipeline material would be consistent with pipeline safety.

(3) Repairs or replacements using materials authorized under this part do not require notification under this section.

■ 13. In § 192.13, paragraphs (a) and (b) are revised to read as follows:

§ 192.13 What general requirements apply to pipelines regulated under this part?

(a) No person may operate a segment of pipeline listed in the first column of paragraph (a)(3) of this section that is readied for service after the date in the second column, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part according to the requirements in § 192.14.

(3) The compliance deadlines are as follows:

Pipeline	Date
(i) Offshore gathering pipeline.	July 31, 1977.
(ii) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006.	March 15, 2007.
(iii) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022.	May 16, 2023.
(iv) All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column of this paragraph (b) that is replaced, relocated, or otherwise changed after the date in the second column of this paragraph (b), unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
(1) Offshore gathering pipeline.	July 31, 1977.
(2) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006.	March 15, 2007.
(3) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022.	May 16, 2023.
(4) All other pipelines	November 12, 1970.

* * * * *

■ 14. In § 192.18, paragraph (c) is revised to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if the notification is made pursuant to § 192.8(b)(2), § 192.9(g)(4)(ii) and (h), § 192.461(g), § 192.506(b), § 192.607(e)(4) and (5), § 192.619(c)(2), § 192.624(c)(2)(iii) and (c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv) and (e)(2)(i)(E), § 192.921(a)(7), § 192.927(b), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*i.e.,* ''other technology'') that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

■ 15. Amend § 192.150 as follows:

■ a. In paragraph (b)(7)(ii), remove the word ''and'';

■ b. Redesignate paragraph (b)(8) as paragraph (b)(9); and

■ c. Add a new paragraph (b)(8).

The addition reads as follows:

§ 192.150 Passage of internal inspection devices.

* * * * *

(b) * * *

(8) Gathering lines; and

* * * * *

■ 16. In § 192.452, revise the section heading and paragraph (b) introductory text and add paragraphs (c) and (d) to read as follows:

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering pipelines?

* * * * *

(b) *Type A and B onshore gathering lines.* For any Type A or Type B regulated onshore gathering line under § 192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under § 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

* * * * *

(c) *Type C onshore regulated gathering lines.* For any Type C onshore regulated gathering pipeline under § 192.9 existing on May 16, 2022, that was not previously subject to this part, and for any Type C onshore gas gathering pipeline that becomes subject to this subpart after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

(d) *Regulated onshore gathering lines generally.* Any gathering line that is subject to this subpart per § 192.9 at the time of construction must meet the requirements of this subpart applicable to pipelines installed after July 31, 1971.

■ 17. In § 192.619, revise paragraph (a)(3) and paragraph (c) to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) * * *

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
(i) Onshore regulated gathering pipeline (Type A or Type B under § 192.9(d)) that first became subject to this part (other than § 192.612) after April 13, 2006.	March 15, 2006, or date pipeline becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
(ii) Onshore regulated gathering pipeline (Type C under § 192.9(d)) that first became subject to this part (other than § 192.612) on or after May 16, 2022.	May 16, 2023, *or date pipeline becomes subject to this part, whichever is later.*	5 years preceding applicable date in second column.
(iii) Onshore transmission pipeline that was a gathering pipeline not subject to this part before March 15, 2006.	March 15, 2006, or date pipeline becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
(iv) Offshore gathering pipelines	July 1, 1976	July 1, 1971.
(v) All other pipelines	July 1, 1970	July 1, 1965.

* * * * *

(c) The requirements on pressure restrictions in this section do not apply in the following instances:

(1) An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611.

(2) For any Type C gas gathering pipeline under § 192.9 existing on or before May 16, 2022, that was not previously subject to this part and the operator cannot determine the actual operating pressure of the pipeline for the 5 years preceding May 16, 2023, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA. The operator must notify PHMSA in accordance with § 192.18. The notification must include the following information:

(i) The proposed MAOP of the pipeline;

(ii) Description of pipeline segment for which alternate methods are used to establish MAOP, including diameter, wall thickness, pipe grade, seam type, location, endpoints, other pertinent material properties, and age;

(iii) Pipeline operating data, including operating history and maintenance history;

(iv) Description of methods being used to establish MAOP;

(v) Technical justification for use of the methods chosen to establish MAOP; and

(vi) Evidence of review and acceptance of the justification by a qualified technical subject matter expert.

* * * * *

Issued in Washington, DC on November 2, 2021, under authority delegated in 49 CFR 1.97.

Tristan H. Brown,

Acting Administrator.

[FR Doc. 2021–24240 Filed 11–12–21; 8:45 am]

BILLING CODE 4910–60–P

Town	Length (ft)	In-Service Date	Outside Diameter	MAOP	% SMYS at MAOP	Consequence Area Type	Proposed MAOP Reconfirmation Method	Forecast Reconfirmation (Fiscal Year)	Current Estimated Capital Cost
Hawesville	206	7/25/1969	6.625	594	43.6%	N/A	Pipe Replacement	2025	$2,677,220
Hawesville	5916	7/16/1968	8.625	594	56.8%	N/A	Pressure Reduction	2025	
Hawesville	5650	12/5/1964	6.625	594	29.9%	N/A	Pipe Replacement	2026	$6,124,697
Madisonville	6142		6.625	594	43.6%	MCA	Pipe Replacement	2026	
Madisonville	4699	11/25/1955	6.625	425	23.5%	N/A	Pipe Replacement	2026	
Hawesville	5322	11/15/1966	6.625	500	36.7%	N/A	Pressure Test	2027	
Paducah	20333	11/14/1954	8.625	395	28.4%	N/A	Pipe Replacement	2028	
Bowling Green	10771	2/24/1995	8.625	814	44.5%	N/A	Pressure Reduction	2030	
Paducah	8886	12/4/1969	8.625	395	37.8%	N/A	Pipe Replacement	2031	
Paducah	5185	9/16/1958	8.625	395	37.8%	N/A	Pipe Replacement	2032	
Paducah	3860	9/4/1956	8.625	395	37.8%	N/A	Pipe Replacement	2032	
Bon Harbor	2202	8/1/1964	6.625	529	38.8%	N/A	Pipe Replacement	2033	
Paducah	15850	10/12/1959	8.625	395	37.8%	N/A	Pipe Replacement	2034	
Paducah	667	7/13/1970	6.625	395	29.0%	MCA	Pipe Replacement	2034	

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Index No.	Category	Project Description	Project Type	Project Justification	Estimated Start & Completion Dates	2025 Cost Estimate with Estimated Overheads	Regulatory Requirement (49 CFR)	Advancement of Safety/System Integrity	Alternatives	Transmission or Distribution	Discussion
1	Equipment	THIS PROJECT IS TO PURCHASE TOOLS AND EQUIPMENT FOR THE KENTUCKY SERVICE AREA INCLUDING, BUT NOT LIMITED TO: SENSIT GOLDS, PIPE LOCATORS, LEAK DETECTION EQUIPMENT, JD EXCAVATOR, AND VALVE CHANGERS.	Specific	Purpose & Necessity: This funding project provides monies for the purchase of various pieces of equipment in the Kentucky service area to 1) replace existing units that require excessive maintenance, 2) ensure employee and customer safety during construction & maintenance activities, or 3) outfit construction crews and service personnel with the needed equipment to install and/or retire main, service lines, and metering/regulating facilities. Towns where equipment purchases may be made include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2024/September 2025	$1,215,091	N/A	N/A	N/A	N/A	N/A
2	Equipment Total					$1,215,091					
3	Growth	THIS PROJECT IS TO INSTALL GROWTH SERVICES, METERS, AND METER LOOPS FOR THE KENTUCKY SERVICE AREA	Functional*	Purpose & Necessity: This funding project provides monies for the installation of growth services, meters, regulators, and meter loops in the Kentucky servcie area. These service lines will be installed under functional (blanket) projects in order to serve new customers. Towns where equipment purchases may be made include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2024/September 2025	$5,036,972	N/A	N/A	N/A	Distribution	N/A
4	Growth	THIS PROJECT IS FOR MISCELLANEOUS GROWTH MAIN IN THE KENTUCKY SERVICE AREA	Specific	Purpose & Necessity: This funding project provides monies to extend mains in the Kentucky service area in order to serve 1) residential customers in new subdivisions or additional phases of existing developments, 2) conversion customers, or 3) new or additional incremental loads from commercial/industrial customers. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2024/September 2025	$1,608,281	N/A	N/A	N/A	Distribution	N/A
5	Growth	THIS PROJECT IS TO INSTALL HPD IN PRIVATE EASEMENT - PROJECT VISTA	Specific	Purpose & Necessity: This funding project provides monies to Install 3600' of 6" HPD, estimated footage for railroad bore, all in private easement, customer to provide ditch	October 2024/September 2025	$1,114,896	N/A	N/A	N/A	Distribution	N/A
6	Growth Total					$7,760,149					
7	Information Technology	THIS PORJECT IS TO REPLACE MDT'S, DESKTOPS, LAPTOPS, AND MISC ITEMS FOR THE KENTUCKY SERVICE AREA	Specific	Purpose & Necessity: This funding project provides monies for the replacement of desktop and laptop computers, and mobile display terminals (MDT's). This changeout process is driven by the need to maintain network functionality and compatibility in terms of hardware and software. Technology changes for these computing devices are occurring at a rapid pace which makes older equipment obsolete and unable to properly function with newer computers.	October 2024/September 2025	$143,197	N/A	N/A	N/A	N/A	N/A
8	Information Technology Total					$143,197					
9	Public Improvements	THIS PORJECT IS TO FUND VARIOUS MISCELLAENOUS PUBLIC IMPROVEMENTS	Specific	Purpose & Necessity: This funding project provides monies for the various miscellaneous public improvement projects that may arise throughout the Kentucky service area.	October 2024/September 2025	$67,081	N/A	N/A	N/A	N/A	N/A
10	Public Improvements Total					$67,081					
11	Structures	THIS PROJECT IS TO PURCHASE MATERIALS AND CONSTRUCT MISCELLANEOUS STRUCUTRAL IMPROVEMENTS ACROSS THE KENTUCKY SERVICE AREA.	Specific	Purpose & Necessity: This funding project provides monies for the material procurement, construction, and installation of various structural and/or building improvements in the Kentucky service area. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2024/September 2025	$221,811	N/A	N/A	N/A	N/A	N/A
12	Structures Total					$221,811					
13	System Improvements	STATEWIDE: PURCHASE AND INSTALL TOWERS AND ENDPOINTS.	Specific	Purpose & Necessity: This funding project provides monies for the installation of the end-points needed to finish converting the remaining areas around the state to wireless meter reading (WMR). This is a multi-year project and should be completed in FY2028. The benefits of WMR are 1) increased accuracy in customer billing, 2) enhanced operational monitoring of various distribution systems, and 3) immediate alerts of meter malfunctions.	October 2024/September 2025	$2,788,856	N/A	N/A	N/A	Distribution	
14	System Improvements	THIS PROJECT IS TO INSTALL HPD HPD FROM ZARING MILL ROAD TO PIERCE INDUSTRIAL ROAD	Specific	Purpose & Necessity: This funding project provides monies which will be utilized to install 5100' of 8" Steel HPD from Zaring Mill Road to Pierce Industrial Road to provide necessary additional capacity for Industrial Park.	October 2024/September 2025	$2,586,765	N/A	N/A	N/A	Distribution	
15	System Improvements	THIS PROJECT IS FOR THE CONSTRUCTION OF WILD TURKEY REINFORCEMENT	Specific	Purpose & Necessity: This funding project provides monies which will be utilized to replace 17,500' of 8" Steel, 2600' of 6" HDPE, 1100' of 2" HDPE to serve Wild Turkey Expansion.	October 2024/September 2025	$2,227,142	N/A	N/A	N/A	Distribution	
16	System Improvements	THIS PROJECT ADDRESSES REPLACING MISCELLANEOUS MEASUREMENT ITEMS	Specific	Purpose & Necessity: This funding project provides monies to replace miscellaneous emergency regulators, upgrade ERX, and replace obsolete RTUs across the Kentucky service area. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2024/September 2025	$343,571	N/A	N/A	N/A	Distribution	
17	System Improvements	THIS PROJECT IS TO INSTALL PE ALONG SOUTH GUM SPRING ROAD	Specific	Purpose & Necessity: This funding project provides monies which will be utilized to install 4,000 feet of 4 in PE along South Gum Spring Rd to add necessary capacity to the Lone Oak System	October 2024/September 2025	$249,910	N/A	N/A	N/A	Distribution	
18	System Improvements Total					$8,196,244					
19	System Integrity	THIS PROJECT IS TO REPLACE MAINS, SERVICES, METER LOOPS, AND INSTALL ANODES FOR NON-GROWTH FOR THE KENTUCKY SERVCIE AREA	Functional	Purpose & Necessity: This funding project provides monies for the relocation and/or abandonment of mains, services, meters, regulators, meter loops, and installation of anodes in the Kentucky service area. This work is performed daily and is captured via functional (blanket) projects. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2024/September 2025	$8,967,778	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks

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Index No.	Category	Project Description	Project Type	Project Justification	Estimated Start & Completion Dates	2025 Cost Estimate with Estimated Overheads	Regulatory Requirement (49 CFR)	Advancement of Safety/System Integrity	Alternatives	Transmission or Distribution	Discussion
20	System Integrity	THIS PROJECT IS TO REPLACE MAINS AND SERVICES FOR LEAK REPAIRS FOR THE KENTUCKY SERVICE AREA	Functional	Purpose & Necessity: This funding project provides monies for leak repairs of mains and services in the Kentucky service area. This work is performed daily and is captured via functional (blanket) projects. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2024/September 2025	$1,071,216	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
21	System Integrity	THIS PROJECT IS FOR MISCELLANEOUS SYSTEM INTEGRITY PROJECTS IN THE KENTUCKY SERVICE AREA	Specific	Purpose & Necessity: This funding project provides monies for the replacement of mains and regulators stations at various locations throughout the Kentucky service area. Pipe is in need of replacement due to the following threats: bare steel or poor coating, invasion tubing, isolated steel, exposures, early generation plastic, and antiquated joining/construction techniques. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2024/September 2025	$67,081	§192.1007	Continued elimination of highest risked assets and reduces the threat of failure from corrosion, materials, welds, or joints	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
22	System Integrity	THIS PROJECT IS FOR THE PURCHASE OF METHANE LEAK DETECTION EQUIPMENT AT HICKORY STORAGE WELLS	Specific	Purpose & Necessity: This funding project provides monies for the purchase of Methane Leak Detection Equipment at Hickory storage wells to provide continuous remote methane emission monitoring of our wellhead assets	November 2024/July 2025	$809,589	40 CFR 60 (§60.5397 OOOO)	Continuous monitoring of methane leak detection on storage assets	N/A	Storage/Wells	CFR Title 40 (Protection of Environment) Part 60 (Standards of Performance for new Stationary Sources) Subpart OOOO
23	System Integrity	THIS PROJECT IS FOR THE REPLACEMENT OF FOUR WELLHEADS	Specific	Purpose & Necessity: This funding project provides monies for the replacement of four wellheads to update aging isolation master and wing valves at Grandview Storage Field (Daviess County, KY) and St. Charles Storage Field (Hopkins County, KY)	November 2024/August 2025	$1,607,404	§192.12 --> API RP 1171	Replacement of isolation valves on wellheads	N/A	Storage/Wells	§192.12: Underground Natural Gas Storage Facilities (d) Integrity management program incorporates American Petroleum Institute Recommended Practice (API RP) 1171 (Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs)
24	System Integrity	THIS PROJECT IS FOR MISCELLANEOUS LARGE VOLUME METERSETS IN THE KENTUCKY SERVICE AREA	Specific	Purpose & Necessity: This funding project provides monies for the replacement of aging miscellaneous large volume metersets	October 2024/September 2025	$209,820	N/A	Continued risk elimination from aging metersets	N/A	Distribution	
25	System Integrity	THIS PROJECT IS FOR THE REPLACEMENT OF HAWESVILLE REG STATION	Specific	Purpose & Necessity: This funding project provides monies for the installing meter/regulator stations, valves and pipeline for Hawesville where we must reconfirm the MAOP of the pipeline per updated federal code regulation 192.624	October 2024/September 2025	$2,677,220	§192.624	Replacement of pipe to establish MAOP on transmission pipeline	1). Pressure Test 2) Pressure Reduction	Transmission	MAOP Reconfirmation
26	System Integrity	THIS PROJECT IS FOR REPLACEMENT OF SALOMA HPD BLOCK VALVE	Specific	Purpose & Necessity: This funding project provides monies for the replacement of block valve on Saloma to Campbellsville HPD 6" Steel to provide valve mainentance and replacement on aging distribution line valve	April 2025/June 2025	$93,405	§192.181 §192.747	Continued elimination of risk associated with sectionalizing block valves operability	N/A	Distribution	§192.181 Distribution Line Valves §192.747 Valve Maintenance: Distribution Systems
27	System Integrity	THIS PROJECT IS FOR REPLACEMENT OF GREENSBURG HPD BLOCK VALVE	Specific	Purpose & Necessity: This funding project provides monies for the retirement of existing block valve and relocate new block valve on Summersville to Greensburg HPD 4" steel	April 2025/June 2025	$102,305	§192.181 §192.747	Continued elimination of risk associated with sectionalizing block valves operability and location	N/A	Distribution	§192.181 Distribution Line Valves §192.747 Valve Maintenance: Distribution Systems
28	System Integrity	THIS PROJECT IS FOR REPLACEMENT OF MEARS FARM HPD EXPOSURE	Specific	Purpose & Necessity: This funding project provides monies for the replacement of 250' of 4" to eliminate exposure on HPD line between Summersville and Greensburg for continued mitigation of third party damage	June 2025/August 2025	$102,552	§192.613 §192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	§192.613 Continuing Surveillance §192.1007 Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks

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Index No.	Category	Project Description	Project Type	Project Justification	Estimated Start & Completion Dates	2025 Cost Estimate with Estimated Overheads	Regulatory Requirement (49 CFR)	Advancement of Safety/System Integrity	Alternatives	Transmission or Distribution	Discussion
29	System Integrity	THIS PROJECT IS FOR INSTALLATION OF CALHOUN TOWN BORDER	Specific	Purpose & Necessity: This funding project provides monies for the installation of replacement regulator station to relocate RS1379 to more rural area	April 2025/June 2025	$153,327	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
30	System Integrity	THIS PROJECT IS FOR BOWLING GREEN TOWN BORDER FOUR REPLACEMENT	Specific	Purpose & Necessity: This funding project provides monies for the replacement of TB 4 off Smallhouse Rd. New site across Smallhouse Rd and new station with dual runs.	April 2025/July 2025	$649,852	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
31	System Integrity	THIS PROJECT IS FOR INSTALLATION OF REG STATION AT BRANSHAW AND PEMBROOK	Specific	Purpose & Necessity: This funding project provides monies for the installation of new regulator station to relocate RS1639 to install on private property away from State Right of Way	April 2025/June 2025	$151,623	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
32	System Integrity Total					$16,663,172					
33	Grand Total					$34,266,745					
	*Functional Project Types close monthly										

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Index No.	Category	Project Description	Project Type	Project Justification	Estimated Start & Completion Dates	2026 Cost Estimate with Estimated Overheads	Regulatory Requirement (49 CFR)	Advancement of Safety/System Integrity	Alternatives	Transmission or Distribution	Discussion
1	Equipment	THIS PROJECT IS TO PURCHASE TOOLS AND EQUIPMENT FOR THE KENTUCKY SERVICE AREA INCLUDING, BUT NOT LIMITED TO: SENSIT GOLDS, PIPE LOCATORS, LEAK DETECTION EQUIPMENT, JD EXCAVATOR, AND VALVE CHANGERS.	Specific	Purpose & Necessity: This funding project provides monies for the purchase of various pieces of equipment in the Kentucky service area to 1) replace existing units that require excessive maintenance, 2) ensure employee and customer safety during construction & maintenance activities, or 3) outfit construction crews and service personnel with the needed equipment to install and/or retire main, service lines, and metering/regulating facilities. Towns where equipment purchases may be made include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2025/September 2026	$799,000	N/A	N/A	N/A	N/A	N/A
2	Equipment Total					$799,000					
3	Growth	THIS PROJECT IS TO INSTALL GROWTH SERVICES, METERS, AND METER LOOPS FOR THE KENTUCKY SERVICE AREA	Functional*	Purpose & Necessity: This funding project provides monies for the installation of growth services, meters, regulators, and meter loops in the Kentucky servcie area. These service lines will be installed under functional (blanket) projects in order to serve new customers. Towns where equipment purchases may be made include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2025/September 2026	$5,276,000	N/A	N/A	N/A	Distribution	N/A
4	Growth	THIS PROJECT IS FOR MISCELLANEOUS GROWTH MAIN IN THE KENTUCKY SERVICE AREA	Specific	Purpose & Necessity: This funding project provides monies to extend mains in the Kentucky service area in order to serve 1) residential customers in new subdivisions or additional phases of existing developments, 2) conversion customers, or 3) new or additional incremental loads from commercial/industrial customers. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2025/September 2026	$1,600,000	N/A	N/A	N/A	Distribution	N/A
5	Growth	THIS PROJECT IS FOR ENVISION - PHASE 2	Specific	Purpose & Necessity: This funding project provides monies to Install approximately 2200' of 8" steel to serve the second phase. Meter location is TBD.	October 2025/September 2026	$563,237	N/A	N/A	N/A	Distribution	N/A
6	Growth Total					$7,439,237					
7	Information Technology	THIS PORJECT IS TO REPLACE MDT'S, DESKTOPS, LAPTOPS, AND MISC ITEMS FOR THE KENTUCKY SERVICE AREA	Specific	Purpose & Necessity: This funding project provides monies for the replacement of desktop and laptop computers, and mobile display terminals (MDT's). This changeout process is driven by the need to maintain network functionality and compatibility in terms of hardware and software. Technology changes for these computing devices are occurring at a rapid pace which makes older equipment obsolete and unable to properly function with newer computers.	October 2025/September 2026	$235,000	N/A	N/A	N/A	N/A	N/A
8	Information Technology Total					$235,000					
9	Structures	THIS PROJECT IS TO PURCHASE MATERIALS AND CONSTRUCT MISCELLANEOUS STRUCUTRAL IMPROVEMENTS ACROSS THE KENTUCKY SERVICE AREA.	Specific	Purpose & Necessity: This funding project provides monies for the material procurement, construction, and installation of various structural and/or building improvements in the Kentucky service area. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2025/September 2026	$563,237	N/A	N/A	N/A	N/A	N/A
10	Structures Total					$563,237					
11	System Improvements	THIS PROJECT IS FOR THE CONSTRUCTION OF OHIO VALLEY REINFORCEMENT PHASE 2	Specific	Purpose & Necessity: This funding project provides monies which will be utilized to Install 6800' of 8" Steel HPD from Pierce Industrial Road to Ohio Valley to provide necessary added capacity to industrial customers in industrial park	October 2025/September 2026	$3,093,099	N/A	N/A	N/A	Distribution	
12	System Improvements	THIS PROJECT IS FOR THE CONSTRUCTION OF KY-210 REINFORCEMENT	Specific	Purpose & Necessity: This funding project provides monies which will be utilized for running 1000' of 4" HDPE to kill two one way feed systems and make it a two way feed.	October 2025/January 2026	$104,874	N/A	N/A	N/A	Distribution	
13	System Improvements	THIS PROJECT IS TO INSTALL GLASGOW PURCHASE 32	Specific	Purpose & Necessity: This funding project provides monies which will be utilized to rebuild Glasgow #2 Purchase to update aging infrastructure and provide updated assets to eliminate risk and third party damage	March 2026/July 2026	$1,373,974	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
14	System Improvements	THIS PROJECT IS FOR THE CONSTRUCITON OF THE SCOTT STATION ROAD REINFORCEMENT	Specific	Purpose & Necessity: This funding project provides monies which will be utilized to run 2300' of 4" HDPE along Scott Station road to eliminate pressure issues on existing 3/4" main	October 2025/September 2026	$188,326	N/A	N/A	N/A	Distribution	
15	System Improvements Total					$4,760,273					
16	System Integrity	THIS PROJECT IS TO REPLACE MAINS, SERVICES, METER LOOPS, AND INSTALL ANODES FOR NON-GROWTH FOR THE KENTUCKY SERVCIE AREA	Functional	Purpose & Necessity: This funding project provides monies for the relocation and/or abandonment of mains, services, meters, regulators, meter loops, and installation of anodes in the Kentucky service area. This work is performed daily and is captured via functional (blanket) projects. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2025/September 2026	$8,358,000	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
17	System Integrity	THIS PROJECT IS TO REPLACE MAINS AND SERVICES FOR LEAK REPAIRS FOR THE KENTUCKY SERVICE AREA	Functional	Purpose & Necessity: This funding project provides monies for leak repairs of mains and services in the Kentucky service area. This work is performed daily and is captured via functional (blanket) projects. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2025/September 2026	$1,244,000	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks

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Index No.	Category	Project Description	Project Type	Project Justification	Estimated Start & Completion Dates	2026 Cost Estimate with Estimated Overheads	Regulatory Requirement (49 CFR)	Advancement of Safety/System Integrity	Alternatives	Transmission or Distribution	Discussion
18	System Integrity	THIS PROJECT IS FOR MISCELLANEOUS SYSTEM INTEGRITY PROJECTS IN THE KENTUCKY SERVICE AREA	Specific	Purpose & Necessity: This funding project provides monies for the replacement of mains and regulators stations at various locations throughout the Kentucky servcie area. Pipe is in need of replacement due to the following threats: bare steel or poor coating, invasion tubing, isolated steel, exposures, early generation plastic, and antiquated joining/construction techniques. Towns where this work may be done include, but are not limited to the following: Owensboro, Paducah, Mayfield, Campbellsville, Hopkinsville, Bowling Green, Glasgow, Danville, Madisonville, Princeton, & Shelbyville	October 2025/September 2026	$69,000	§192.1007	Continued elimination of highest risked assets and reduces the threat of failure from corrosion, materials, welds, or joints	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
19	System Integrity	THIS PROJECT IS FOR REPLACEMENT OF HICKORY WELLHEADS	Specific	Purpose & Necessity: This funding project provides monies to replace 10 wellheads at Hickory Storage field in Daviess County, KY to provide continued mitigation of risk of aging isolation valves on wellheads	October 2025/September 2026	$1,970,570	§192.12 --> API RP 1171	Replacement of isolation valves on wellheads	N/A	Storage/Wells	§192.12: Underground Natural Gas Storage Facilities (d) Integrity management program incorporates American Petroleum Institute Recommended Practice (API RP) 1171 (Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs)
20	System Integrity	THIS PROJECT IS FOR REPLACEMENT OF WELL AT BON HARBOR	Specific	Purpose & Necessity: This funding project provides monies for the replacement of a well at Bon Habror (BH#1) eliminating the risk of wells per our developed risk model for wells and wellheads.	October 2025/September 2026	$1,451,822	§192.12 --> API RP 1171	Continued elimination of our higher risk wells developed in our risk model	N/A	Storage/Wells	§192.12: Underground Natural Gas Storage Facilities (d) Integrity management program incorporates American Petroleum Institute Recommended Practice (API RP) 1171 (Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs)
21	System Integrity	THIS PROJECT IS FOR THE PURCHASE OF METHANE LEAK DETECTION EQUIPMENT AT BON HARBOR STORAGE WELLS	Specific	Purpose & Necessity: This funding project provides monies for the purchase of Methane Leak Detection Equipment at Bon Harbor storage wells to provide continuous remote methane emission moitoring of our wellhead assets	November 2025/July 2026	$142,774	40 CFR 60 (§60.5397 OOOO)	Continuous monitoring of methane leak detection on storage assets	N/A	Storage/Wells	CFR Title 40 (Protection of Environment) Part 60 (Standards of Performance for new Stationary Sources) Subpart OOOO
22	System Integrity	THIS PROJECT IS FOR THE PURCHASE OF METHANE LEAK DETECTION EQUIPMENT AT BON HARBOR STATION	Specific	Purpose & Necessity: This funding project provides monies for the purchase Bon Habror Station Methane Leak Detection Equipment.	November 2025/July 2026	$60,625	40 CFR 60 (§60.5397 OOOO)	Continuos monitoring of methane leak detection on storage assets	N/A	Storage/Wells	CFR Title 40 (Protection of Environment) Part 60 (Standards of Performance for new Stationary Sources) Subpart OOOO
23	System Integrity	THIS PROJECT IS FOR THE PURCHASE OF SUGG STREET UPGRADE	Specific	Purpose & Necessity: This funding project provides monies to replace and/or reroute 1100' of 2" HDPE under hard surface from Sugg Street along Bishop Alley. Cost includes main and 18 services	March 2026/August 2026	$515,204	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
24	System Integrity	THIS PROJECT IS FOR THE PURCHASE OF THE DAWSON SPRINGS TBS	Specific	Purpose & Necessity: This funding project provides monies to install new regulator station to replace RS1625 and RS1621	April 2026/June 2026	$183,080	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks

FY2024 ATMOS ENERGY CAPITAL EXPENDITURES BUDGET

Exhibit TRA-7

	A	B	C	D	E	F	G	H	I	J	K
Index No.	Category	Project Description	Project Type	Project Justification	Estimated Start & Completion Dates	2026 Cost Estimate with Estimated Overheads	Regulatory Requirement (49 CFR)	Advancement of Safety/System Integrity	Alternatives	Transmission or Distribution	Discussion
25	System Integrity	THIS PROJECT IS FOR THE PURCHASE OF WELL METHANE LEAK DETECTION EQUIPMENT AT ST CHARLES	Specific	Purpose & Necessity: This funding project provides monies for the purchase of Well Methane Leak Detection Equipment at St Charles storage wells to provide continuous remote methane emission moitoring of our wellhead assets	February 2026/June 2026	$677,271	40 CFR 60 (§60.5397 OOOO)	Continuous monitoring of methane leak detection on storage assets	N/A	Storage/Wells	CFR Title 40 (Protection of Environment) Part 60 (Standards of Performance for new Stationary Sources) Subpart OOOO
26	System Integrity	THIS PROJECT IS FOR THE PURCHASE OF WELL METHANE LEAK DETECTION EQUIPMENT AT GRANDVIEW	Specific	Purpose & Necessity: This funding project provides monies for the purchase of Well Methane Leak Detection Equipment at Grandview storage wells to provide continuous remote methane emission moitoring of our wellhead assets	October 2025/September 2026	$514,175	40 CFR 60 (§60.5397 OOOO)	Continuous monitoring of methane leak detection on storage assets	N/A	Storage/Wells	CFR Title 40 (Protection of Environment) Part 60 (Standards of Performance for new Stationary Sources) Subpart OOOO
27	System Integrity	THIS PROJECT IS FOR MISCELLANEOUS LARGE VOLUME METERSETS IN THE KENTUKY SERVICE AREA	Specific	Purpose & Necessity: This funding project provides monies for the replacement of aging miscellaneous large volume metersets	October 2025/September 2026	$200,000	N/A	Continued risk elimination from aging metersets	N/A	Distribution	
28	System Integrity	THIS PROJECT IS FOR LIBERTY PURCHASE INLET PIPING	Specific	Purpose & Necessity: This funding project provides monies for the acquisition of ROW and replacement of approximately 7000' of 6" Transmission pipeline in Madisonville, KY for Liberty Purchase Inlet pipe. This project relocates the pipeline to a more rural area andre-establishes the MAOP on this section of pipeline per updated federal code regulation 192.624	October 2025/September 2026	$2,392,977	§192.624	Replacement of pipe to establish MAOP on transmission pipeline	1). Pressure Test 2) Pressure Reduction	Transmission	MAOP Reconfirmation
29	System Integrity	THIS PROJECT IS FOR ALERIS MEASUREMENT AND REG STATION UPGRADE	Specific	Purpose & Necessity: This funding project provides monies for upgrading measurement and regulation for Aleris Industrial Site for continued mitigation of third party damage and removing aging infrastructure from the station lot	October 2025/August 2026	$828,415	§192.1007	Continued mitigation of third party damage, external forces, & equipment failure	N/A	Transmission	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
30	System Integrity	THIS PROJECT IS FOR GROUNDBED REPLACEMENT	Specific	Purpose & Necessity: This funding project provides monies for replacing aging rectifiers/groundbeds at Pepper Drive and Liberty Church	October 2025/September 2026	$121,572	§192.455 §192.457	Continued mitigation of external corrosion threat	N/A	Distribution	External Corrosion Contro
31	System Integrity	THIS PROJECT IS FOR HANSON TBS	Specific	Purpose & Necessity: This funding project provides monies for the replacement of Hanson Town Border RS10629	October 2025/September 2026	$139,835	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
32	System Integrity	THIS PROJECT IS FOR PRINCETON TBS #2	Specific	Purpose & Necessity: This funding project provides monies for the replacement of outdated town border station	October 2025/September 2026	$131,608	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
33	System Integrity	THIS PROJECT IS FOR LEBANON ROAD FARM TAP STATIONS	Specific	Purpose & Necessity: This funding project provides monies to run 1100 feet of 2" HDPE and set new 2" regulator station at Alum Springs Crosspike to retire RS1478, RS1479	March 2026/August 2026	$224,892	§192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
34	System Integrity	THIS PROJECT IS FOR THE REPLACEMENT OF HAWESVILLE REG STATION 192.624 PH2	Specific	Purpose & Necessity: This funding project provides monies to complete installing 12" Pipeline, valves, pig launchers and cathodic protection on Hawesville Transmission Line that begins at TX Gas High Rise Station. MAOP on this section of existing pipeline must be re-established per federal code regulation 192.624	October 2025/September 2026	$2,108,782	§192.624	Replacement of pipe to establish MAOP on transmission pipeline	1). Pressure Test 2) Pressure Reduction	Transmission	MAOP Reconfirmation
35	System Integrity	THIS PROJECT IS FOR THE STATION REPLACEMENT IN TRI ACRES, GREENSBURG	Specific	Purpose & Necessity: This funding project provides monies to replace outdated RS1772 in Greensburg	October 2025/December 2025	$59,062	§192.1007	Continued mitigation of third party damage, external forces, & equipment failure	N/A	Distribution	
36	System Integrity	THIS PROJECT IS TO REPLACE TRANSMISION PIPELINE ON LEGION DRIVE	Specific	Purpose & Necessity: This funding project provides monies to replace approximately 3700' of 6" Transmission pipeline from Legion Drive and relocates the transmission pipeline to more rural route in the area. Replacement of this pipeline necessary to re-establish MAOP per federal code regulation 192.624	October 2025/September 2026	$1,622,938	§192.624	Replacement of pipe to establish MAOP on transmission pipeline	1). Pressure Test 2) Pressure Reduction	Transmission	

FY2024 ATMOS ENERGY CAPITAL EXPENDITURES BUDGET

Exhibit TRA-7

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Index No.	Category	Project Description	Project Type	Project Justification	Estimated Start & Completion Dates	2026 Cost Estimate with Estimated Overheads	Regulatory Requirement (49 CFR)	Advancement of Safety/System Integrity	Alternatives	Transmission or Distribution	Discussion
37	System Integrity	THIS PROJECT IS FOR MILBY FARM HPD EXPOSURE	Specific	Purpose & Necessity: This funding project provides monies to replace 80' of 4" to eliminate exposure on HPD line between Summersville and Greensburg	June 2026/August 2026	$70,651	§192.613 §192.1007	Continued mitigation of third party damage and/or external forces	N/A	Distribution	§192.613 Continuing Surveillance §192.1007 Required Elements of Integrity Management Plan: (a) Knowledge (b) Identify Threats (c) Evaluate and rank risk (d) Identify and implement measures to address risks
38	System Integrity Total					$23,087,253					
39	Grand Total					$36,884,000					
	*Functional Project Types close monthly										

safety procedures used for filling, operating, and discharging MATs to determine whether additional safety procedures should be implemented. To this end, we request that persons who use such transportation systems to provide us with information on the effectiveness of the current DOT regulations, consensus standards, and industry best practices. We are also interested in any other procedures utilized to ensure that operations related to the transportation of acetylene on MATs are performed safely.

We would also like to work with shippers, carriers, and facilities that receive shipments of acetylene in MATs to develop and implement a pilot program to test the effectiveness of current or alternative procedures or methods designed to enhance the safety of transportation operations involving acetylene on MATs. As part of this program, we will assist individual companies or facilities to evaluate the effectiveness of their current procedures and to identify additional measures that should be implemented. We welcome suggestions concerning how such a program should be structured and the entities that should participate.

To ensure that our message reaches all stakeholders affected by these risks, we plan to communicate this advisory through our public affairs notification and outreach processes. For additional visibility, we have made this advisory available on the PHMSA homepage at *http://www.phmsa.dot.gov* and the DOT electronic docket site at *http://dms.dot.gov*. In addition, if you are aware of other companies that are involved in the charging, operating, and discharging MATs, please share this advisory notice with them and, if possible, identify them in your correspondence with this agency. We believe a collaborative effort involving an integrated and cooperative approach will help us to address safety risks, reduce incidents, enhance safety, and protect the public.

Issued in Washington, DC on August 30, 2007.

Theodore L. Willke,

Associate Administrator for Hazardous Materials Safety.

[FR Doc. 07–4355 Filed 9–5–07; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2004–19856]

Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing this updated advisory bulletin to owners and operators of natural gas pipeline distribution systems concerning the susceptibility of older plastic pipe to premature brittle-like cracking. PHMSA previously issued three advisory bulletins on this subject: Two on March 11, 1999 and one on November 26, 2002. This advisory bulletin expands on the information provided in the three prior bulletins by listing two additional pipe materials with poor performance histories relative to brittle-like cracking and by updating pipeline owners and operators on the ongoing voluntary efforts to collect and analyze data on plastic pipe performance. Owners and operators of natural gas pipeline distribution systems are encouraged to review the three previous advisory bulletins in their entirety.

FOR FURTHER INFORMATION CONTACT: Richard Sanders at (405) 954–7214, or by e-mail at *richard.sanders@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. National Transportation Safety Board (NTSB) Investigation

On April 23, 1998, the National Transportation Safety Board (NTSB) issued its Special Investigation Report, *Brittle-Like Cracking in Plastic Pipe for Gas Service,* NTSB/SIR–98/01. The report described the results of the NTSB's special investigation of polyethylene gas service pipe, which addressed three major safety issues: (1) Vulnerability of plastic piping to premature failures due to brittle-like cracking; (2) adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains; and, (3) effectiveness of performance monitoring of plastic pipeline systems to detect unacceptable performance in piping systems.

(1) *Vulnerability of plastic piping to premature failures due to brittle-like cracking:* The NTSB found that failures in polyethylene pipe in actual service are frequently brittle-like, slit failures, not ductile failures. It concluded the number and similarity of plastic pipe accident and non-accident failures indicate past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking for much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s. The NTSB also concluded any potential public safety hazards from these failures are likely to be limited to locations where stress intensification exists. The NTSB went on to state that more durable modern plastic piping materials and better strength testing have made the strength ratings of modern plastic piping more reliable.

(2) *Adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains:* The NTSB concluded that gas pipeline operators had insufficient notification of the brittle-like failure potential for plastic pipe manufactured and used for gas service from the 1960s to the early 1980s. The NTSB also concluded this may not have allowed companies to implement adequate surveillance and replacement programs for older plastic piping. The NTSB explained the Gas Research Institute (GRI) developed a significant amount of data on older plastic pipe but the data was published in codified terms making it insufficient for use by pipeline system operators. The NTSB recommended that manufacturers of resin and pipe, industry trade groups and the Federal government do more to alert pipeline operators to the role played by stress intensification from external forces in the premature failure of plastic pipe due to brittle-like cracking.

(3) *Effectiveness of performance monitoring of plastic pipeline systems as a way of detecting unacceptable performance in piping systems:* The NTSB's analysis noted that Federal regulations require pipeline operators to have an ongoing program to monitor the performance of their pipeline systems. However, the NTSB investigation revealed some gas pipeline operators' performance monitoring programs did not effectively collect and analyze data to determine the extent of possible hazards associated with plastic pipeline systems. The NTSB pointed out, ''such a program must be adequate to detect trends as well as to identify localized problem areas, and it must be able to relate poor performance to specific factors such as plastic piping brands, dates of manufacture (or installation dates), and failure conditions.''

Copies of this report may be obtained by searching the NTSB Web site at *www.ntsb.gov.*

II. Advisory Bulletins Previously Issued by PHMSA

The NTSB made several recommendations to PHMSA and to trade organizations in its 1998 special investigation report. In response, PHMSA issued three advisory bulletins. The first advisory bulletin, ADB–99–01, *Potential Failure Due to Brittle-Like Cracking of Certain Polyethylene Plastic Pipe Manufactured by Century Utility Products Inc,* was published in the **Federal Register** (FR) on March 11, 1999 (64 FR 12211) to advise natural gas pipeline distribution system operators that brittle-like cracking may occur on certain polyethylene pipe manufactured by Century Utility Products, Inc.

The second advisory bulletin, ADB–99–02, *Potential Failures Due to Brittle-Like Cracking of Older Plastic Pipe in Natural Gas Distribution Systems,* was also published in the **Federal Register** on March 11, 1999 (64 FR 12212) to advise natural gas pipeline distribution system operators of the potential for brittle-like cracking of plastic pipes installed between the 1960s and early 1980s.

The third advisory bulletin, ADB–02–07, *Notification of the Susceptibility To Premature Brittle-Like Cracking of Older Plastic Pipe,* was published in the **Federal Register** on November 26, 2002 (67 FR 70806) to reiterate to natural gas pipeline distribution system operators the susceptibility of older plastic pipe to premature brittle-like cracking. The older polyethylene pipe materials specifically identified in ADB–02–07 included, but were not limited to:

- Century Utility Products, Inc. products;
- Low-ductile inner wall ''Aldyl A'' piping manufactured by DuPont Company before 1973; and
- Polyethylene gas pipe designated PE 3306.

This third advisory bulletin also listed several environmental, installation and service conditions in which plastic piping is used that could lead to premature brittle-like cracking failure. PHMSA also described six recommended practices for polyethylene gas pipeline system operators to aid them with identifying and managing brittle-like cracking problems.

III. Plastic Pipe Studies

Beginning January 25, 2001, the American Gas Association (AGA) began to collect data on in-service plastic piping material failures with the objective of identifying trends in the performance of these materials. The resulting leak survey data, collected from 2001 to present, on the county's natural gas distribution systems includes both actual failure information and negative reports (reports of no leads) submitted voluntarily by participating pipeline operating companies.

The AGA, PHMSA, and other industry and state organizations continue to collect and analyze the data. Unfortunately, the data cannot be correlated with the quantities of each plastic pipe material that may be in service across the United States. Therefore, the data does not assess the failure rates of individual plastic pipe materials on a linear basis (i.e. per foot, per mile, etc.). However, the failure data reinforces what is historically known about certain older plastic piping and components. The data also indicates the susceptibility of additional specific materials to brittle-like cracking.

IV. Advisory Bulletin ADB–07–01

To: Owners and Operators of Natural Gas Pipeline Distribution Systems.

Subject: Updated Notification of the Susceptibility of Older Plastic Pipes to Premature Brittle-Like Cracking.

Advisory: All owners and operators of natural gas distribution systems who have installed and operate plastic piping are reminded of the phenomenon of brittle-like cracking. Brittle-like cracking refers to crack initiation in the pipe wall not immediately resulting in a full break followed by stable crack growth at stress levels much lower than the stress required for yielding. This results in very tight, slit-like, openings and gas leaks. Although significant cracking may occur at points of stress concentration and near improperly designed or installed fittings, small brittle-like cracks may be difficult to detect until a significant amount of gas leaks out of the pipe, and potentially migrates into an enclosed space such as a basement. Premature brittle-like cracking requires relatively high localized stress intensification that may result from geometrical discontinuities, excessive bending, improper installation of fittings, dents and/or gouges. Because this failure mode exhibits no evidence of gross yielding at the failure location, the term brittle-like cracking is used. This phenomenon is different from brittle fracture, in which the pipe failure causes fragmentation of the pipe.

All owners and operators of natural gas distribution systems are future advised to review the three earlier advisory bulletins on this issue. In addition to being available in the **Federal Register**, these advisory bulletins are available in the docket, and on PHMSA's Web site at *http://phmsa.dot.gov/* under Pipeline Safety Regulations.

In the first advisory bulletin, ADB–99–01, published on March 11, 1999 (64 FR 12211), PHMSA advises natural gas distribution system operators of the potential for poor resistance to brittle-like cracking of certain polyethylene pipe manufactured by Century Utility Products, Inc. In the second advisory bulletin, ADB–99–02, published on March 11, 1999 (64 FR 12212), PHMSA advises natural gas distribution system operators of the potential for brittle-like cracking of plastic pipes installed between the 1960s and early 1980s.

In the third advisory bulletin, ADB–02–07, published on November 26, 2002 (67 FR 70806), PHMSA reiterates to pipeline operators the susceptibility of some older plastic pipe to premature brittle-like cracking which could substantially reduce the service life of natural gas distribution systems and to explain the mission of the Plastic Pipe Database Committee (PPDC) ''to develop and maintain a voluntary data collection process that supports the analysis of the frequency and causes of in-service plastic piping material failures.'' The advisory bulletin also lists several environmental, installation and service conditions under which plastic piping is used which is used which could lead to premature brittle-like cracking failure. PHMSA also describes six recommended practices for polyethylene gas pipeline system operators to aid them with identifying and managing brittle-like cracking problems.

Lastly, the susceptibility of some polyethylene pipes to brittle-like cracking is dependent on the resin, pipe processing, and service conditions. As noted in ADB–02–07, these older polyethylene pipe materials include, but are not limited to:

- Century Utility Products, Inc. products;
- Low-ductile inner wall ''Aldyl A'' piping manufactured by DuPont Company before 1973; and
- Polyethylene gas pipe designated PE 3306.

The data now supports adding the following pipe materials to this list:

- Delrin insert tap tees; and,
- Plexco service tee Celcon (polyacetal) caps.

Authority: 49 U.S.C. chapter 601 and 49 CFR 1.53.

Issued in Washington, DC, on August 28, 2007.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. 07–4309 Filed 9–5–07; 8:45 am]

BILLING CODE 4910–60–M

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2007–28993]

Pipeline Safety: Adequacy of Internal Corrosion Regulations for Hazardous Liquid Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), U.S. Department of Transportation (DOT).

ACTION: Notice of availability of materials; request for comments.

SUMMARY: This notice announces the availability of materials, including a briefing paper prepared for PHMSA's Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) and data on risks posed by internal corrosion on hazardous liquid pipelines. PHMSA is preparing a report to Congress on the adequacy of the internal corrosion regulations for hazardous liquid pipelines. Participants at a meeting of the THLPSSC discussed issues involved in examining the adequacy of the regulations and requested additional data. PHMSA requests public comment on these matters.

DATES: Submit comments by October 9, 2007.

ADDRESSES: Comments should reference Docket No. PHMSA–2007–28993 and may be submitted in the following ways:

- *E-Gov Web site: http://www.regulations.gov.* This Web site allows the public to enter comments on any **Federal Register** notice issued by any agency. Follow the instructions for submitting comments.
- *Fax:* 1–202–493–2251.
- *Mail:* Docket Management System: U.S. Department of Transportation, Docket Operations, M–30, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001.
- *Hand Delivery:* DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Instructions: Identify the docket number, PHMSA–2007–28993, at the beginning of your comments. If you submit your comments by mail, submit two copies. To receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard. Internet users may submit comments at *http://www.regulations.gov.*

Note: Comments are posted without changes or edits to *http://www.regulations.gov,* including any personal information provided. There is a privacy statement published on *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Barbara Betsock at (202) 366–4361, or by e-mail at *barbara.betsock@dot.gov.*

SUPPLEMENTARY INFORMATION: The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 directs PHMSA to review the internal corrosion regulations in subpart H of 49 CFR part 195 to determine if they are adequate to ensure adequate protection of the public and environment and to report to Congress on the results of the review. As an initial step in the review, PHMSA consulted the THLPSSC at its meeting on July 24, 2007. The briefing paper prepared for the committee members contains preliminary data on risk history as well as questions relating to the internal corrosion regulations. This briefing paper is posted on PHMSA's pipeline Web site (*http://ops.dot.gov*) and has been placed in the docket.

At the meeting, PHMSA officials committed to gathering additional data responding to questions posed by the committee members. PHMSA has updated the data and included data responsive to the committee members. This data is also posted on the pipeline Web site and contained in the docket.

PHMSA requests comments on the adequacy of the internal corrosion regulations and answers to the questions posed in the briefing paper. PHMSA will use these comments in its review of the internal corrosion regulations.

Authority: 49 U.S.C. 60102, 60115, 60117: Sec. 22, Pub. L. 109–468, 120 Stat. 3499.

Issued in Washington, DC on August 27, 2007.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. E7–17538 Filed 9–5–07; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–0675]

Proposed Information Collection Activity: Proposed Collection; Comment Request

AGENCY: Center for Veterans Enterprise, Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: The Center for Veterans Enterprise (CVE), Department of Veterans Affairs (VA), is announcing an opportunity for public comment on the proposed collection of certain information by the agency. Under the Paperwork Reduction Act (PRA) of 1995, Federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension of a currently approved collection, and allow 60 days for public comment in response to the notice. This notice solicits comments for information needed to identify veteran-owned businesses.

DATES: Written comments and recommendations on the proposed collection of information should be received on or before November 5, 2007.

ADDRESSES: Submit written comments on the collection of information through *http://www.Regulations.gov;* or Gail Wegner (00VE), Department of Veterans Affairs, 810 Vermont Avenue, NW., Washington, DC 20420 or e-mail: *gail.wegner@va.gov.* Please refer to ''OMB Control No. 2900–0675'' in any correspondence. During the comment period, comments may be viewed online through the Federal Docket Management System (FDMS) at *http://www.Regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Gail Wegner at (202) 303–3296 or FAX (202) 254–0238.

SUPPLEMENTARY INFORMATION: Under the PRA of 1995 (Pub. L. 104–13; 44 U.S.C. 3501–3521), Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. This request for comment is being made pursuant to section 3506(c)(2)(A) of the PRA.

With respect to the following collection of information, CVE invites comments on: (1) Whether the proposed collection of information is necessary for the proper performance of CVE's functions, including whether the information will have practical utility; (2) the accuracy of CVE's estimate of the burden of the proposed collection of

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

TESTIMONY OF GREGORY K. WALLER

INDEX TO THE DIRECT TESTIMONY
OF GREGORY K. WALLER, WITNESS FOR
ATMOS ENERGY CORPORATION

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EXHIBITS

Exhibit GKW-1 – Gregory K. Waller Testimony and Rate Case Management Experience

Exhibit GKW-2 – Composite Allocation Factors

Exhibit GKW-3 – Base Period to Test Period O&M Comparison

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gregory K. Waller. My business address is 5420 LBJ Freeway, 1600 Lincoln Centre, Dallas, TX 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Atmos Energy Corporation ("Atmos Energy" or "the Company") as Director of Rates & Regulatory Affairs (Shared Services).

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. I am responsible for leading and directing the rates and regulatory activity in Atmos Energy's eight-state service area. This responsibility includes developing the strategy, preparing the revenue deficiency filings, and managing the overall ratemaking process for the Company. My responsibilities include execution of applications for changes to rates and tariffs as part of traditional rate cases, tariff language change proposals, and annual ratemaking mechanisms that the Company files in the eight states in which it has regulated operations.

Q. PLEASE STATE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Arts degree in economics from Dartmouth College in 1994 and an MBA degree from the University of Texas in 2000. I worked as a management consultant from 1994 to 2003 at Harbor Research in Boston, MA (1994-1996) and Towers Perrin in Dallas, TX (1997-2003). I joined Atmos Energy

in 2003 and was named Vice President of Finance for the Kentucky/Mid-States Division (which includes the Company's Kentucky operations) in 2005. From 2012 to 2020, I was Manager, Rates and Regulatory Affairs in Atmos Energy's Shared Services Division. From 2020 – 2022, I was a Director at ScottMadden, an energy and regulatory focused management consulting firm and from 2022 – May 2024, I was Director, Regulatory Shared Services at Liberty Utilities. I returned to Atmos Energy and assumed my current role in June 2024.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS OR ANY OTHER REGULATORY COMMISSION?

A. Yes. I have filed testimony in numerous proceedings before regulatory bodies in 7 states, including the Kentucky Public Service Commission. For a complete list of my regulatory proceeding experience, please see Exhibit GKW-1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am responsible for supporting the calculation of the Company's revenue requirements in this case including the Company's proposed rate base, operating expenses, and revenue deficiency used in establishing base rates for the future test period which is the 12 months ending March 31, 2026. I am sponsoring the following Filing Requirements (FR):

FR 16(6)(a) Forecasted financial data presented as pro forma adjustments to the base period;

FR 16(6)(b) Forecasted adjustments limited to twelve (12) months immediately following the suspension period;

FR 16(6)(c)	Capitalization and net investment rate base;
FR 16(6)(f)	Reconciliation of the rate base and capitalization;
FR 16(7)(c)	Description of all factors used in preparation of the forecast test period - income statement, operation and maintenance expenses, employee and labor expenses, capital construction budget;
FR 16(7)(d)	Annual and monthly budget for the 12month period preceding filing date, the base period and the forecast period;
FR 16(7)(h)	(1) Operating Income Statement; (2) Balance Sheet; (3) Statement of Cash Flows; (4) Revenue Requirements; (9) Employee Level; (10) Labor cost changes; and (12) Rate Base;
FR 16(7)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast;
FR 16(7)(t)	List all commercial or in-house computer software, programs, and models used to develop schedules and work papers associated with this application;

FR 16(7)(u)	Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment;
	Method and amounts allocated during base period and method and estimated amounts to be allocated during forecasted test period;
	Explain how allocator for both base and forecasted test period was determined; and
	All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable;
FR 16(8)(a)	A jurisdictional financial summary for both the base period and the forecasted period that details how the utility derived the amount of the requested revenue increase;
FR 16(8)(b)	A jurisdictional rate base summary for both the base period and the forecasted period with supporting schedules, which include detailed analyses of each component of the rate base;
FR 16(8)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and individual account;
FR 16(8)(d)	Summary of jurisdictional adjustments to operating income;
FR 16(8)(e)	Jurisdictional federal and state income tax summaries;

FR 16(8)(f)	Summary schedules for the base and forecast periods of various expenses;
FR 16(8)(g)	Analysis of payroll costs;
FR 16(8)(h)	Computation of gross revenue conversion factor;
FR 16(8)(i)	Comparative income statements, revenue and sales statistics, base period, forecast period and two (2) years beyond;
FR 16(8)(k)	Comparative financial data.FR 16(7)(c) Description of all factors used in preparation of the forecast test period - income statement, operation and maintenance expenses, employee and labor expenses, capital construction budget.

Q. WHAT ARE THE BASE PERIOD AND TEST PERIOD FOR THIS CASE?

A. The base period is January 1, 2024 through December 31, 2024 ("Base Period") and the forecasted test period is April 1, 2025 through March 31, 2026 ("Test Period")

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes, I am sponsoring Exhibits GKW-1 through GKW-3, which are attached to my testimony. Exhibit GKW-1 lists my regulatory proceeding experience. Exhibit GKW-2 provides the composite factors used to allocate common costs for the

purpose of the Test Period in this rate proceeding. Exhibit GKW-3 is a Base Period to Test Period O&M comparison by cost element.

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND EXHIBITS, AND THEIR ASSOCIATED SCHEDULES, AND MAKE THEM PART OF YOUR TESTIMONY?

A. Yes, I adopt the filing requirements, exhibits, and their associated schedules, and make them a part of my testimony.

Q. WHAT IS THE SOURCE OF THE DATA USED TO COMPLETE THE FILING REQUIREMENTS THAT YOU ARE SPONSORING?

A. The source of the data includes the accounting books and records of the Company which are being sponsored by Company witness Ms. Emily Wiebe along with information provided by Mr. Thomas Troup (revenues, gas cost and margin forecast; sales statistics), Mr. T. Ryan Austin (capital investment forecast), Mr. Joe Christian (capital structure and cash working capital), Mr. Joel Multer (tax related items), Mr. Ned Allis. (shared services and division general office depreciation rates), and Mr. Dylan D'Ascendis (rate of return on equity).

The detail concerning how this information was derived is found in the testimony of these witnesses. The data and information provided by these witnesses is the best available information and was developed consistent with sound ratemaking practices. Further, the methods that I used to determine the Company's revenue requirement in this Case are consistent with the Company's approach in

prior cases before this Commission while recognizing and honoring the Commission's findings in the final Orders of Case Nos. 2017-00349, Case No. 2018-00281, and 2021-00214.[1]

III. REVENUE DEFICIENCY

Q. WHAT IS THE AMOUNT OF ATMOS ENERGY'S REVENUE DEFICIENCY?

A. The amount of revenue deficiency Atmos Energy seeks to recover in its proposed rates is $33,001,164 as shown on line 13 of Schedule A. This deficiency is based on the forecasted Test Period twelve months ended March 31, 2026, an average rate base of $628,233,491 and a required rate of return on rate base of 8.30%. The amount accounts for the expiration of the amortization of the Company's unprotected excess deferred income tax liability ("EDITL") of approximately $8.4 million and the continuation of the amortization of the Company's protected EDITL of $189,998 which is discussed in Section IX of my testimony. The amount is also reduced by a return of the Depreciation Regulatory Liability of $2,188,517 and discussed in Section VIII of my testimony.

Q. WHAT IS THE SOURCE OF FORECASTED TEST PERIOD ADJUSTED OPERATING INCOME OF $25,897,613 SHOWN ON SCHEDULE A, LINE 2?

[1] Please see the Direct Testimonies of Mr. Taylor and Mr. Austin regarding the Company's projected capital expenditure levels in relation to these previous orders.

A. The forecasted Test Period adjusted operating income is determined in Schedule C using inputs discussed in my testimony and the testimony of Company witnesses Thomas Troup.

IV. RATE BASE

Q. HOW DID YOU DETERMINE THE LEVEL OF RATE BASE FOR THE TEST PERIOD?

A. The Test Period rate base of $628,233,491 is summarized in Schedule B-1 and detailed in Schedules B-2 through B-6. Each component of the Test Period rate base is a thirteen-month average forecasted amount, unless noted otherwise. The components of rate base are net plant in service, cash working capital, regulatory assets and liabilities, and an allowance for other working capital items consisting of materials and supplies and gas stored underground, less customer advances for construction and deferred income taxes.

Q. WHAT COMPRISES THE FORECASTED TEST PERIOD CAPITAL PROJECTION?

A. The forecasted Test Period capital investment projection is comprised of three components - the direct capital spending for Kentucky for the forecasted test period, the amount allocated to Kentucky resulting from capital spending by the Kentucky/Mid-States Division's general office and the amount allocated to Kentucky resulting from capital spending by the SSU during the forecasted test period.

Q. HOW WAS THE TEST PERIOD GROSS PLANT IN SERVICE PROJECTED?

A. I began with actual per books net plant (gross plant and accumulated depreciation account balances) as of June 30, 2024, including allocations of shared plant as discussed by Ms. Wiebe in her testimony.[2] I adjusted out balances for assets that the Company is recovering and will continue to recover via its Pipeline Replacement Program ("PRP") mechanism. I used the capital spending projection for July - September 2024 and the fiscal year 2025 budget for the months in fiscal year 2025 (October 2024 through September 2025). The direct 2025 budget is prepared at a project level and is supported by Mr. T. Ryan Austin in his testimony. For the months of the Test Period that represent the first half of the Company's fiscal year 2026 (October 2025 through March 2026), I used project level data provided by Mr. Austin for the direct investment in Kentucky and held the amounts constant from the FY2025 budget for allocable investment. Projected plant retirements were based on the level of retirements recorded in the six months of actuals included in the Base Period (January 2024 through June 2024). Routine retirements in each forecasted month were projected to continue at the same level in the same month in future periods. The Company is not proposing to role its current PRP investment and rates into the base rates in this proceeding. In order to

[2] Please see Exhibit GKW-2 Allocation Factors

ensure recovery of investment once and only once, I did not include capital investments and related retirements that are being recovered and anticipated to be recovered through the PRP. Specifically, the Company is recovering PRP investments made since Case No. 2021-00214 through its PRP mechanism and has already filed a PRP application for PRP investments that will be made through September 2025 rather than including them in this Case.[3]

Q. WHAT KEY PRIORITIES ARE ADDRESSED THROUGH THE KENTUCKY DIRECT CAPITAL BUDGET?

A. Investments that focus on customer safety and system reliability are our highest priorities for capital budgeting. The next priority is public improvements and state and local public works projects such as highway relocations. The next priority is customer growth. Atmos Energy continues to build good working relationships with developers, economic development boards, and growing communities to meet the needs of the customer and to accommodate customer growth on its system. Next in order of priority, a modern fleet of vehicles and equipment (backhoes, safety equipment, ditchers, first responder equipment, air compressors, welding machines, etc.) allows us to maintain our system and continue to provide a reliable and efficient level of service to our customers. To enhance the level of customer

[3] Case No. 2024-00226, *Electronic Application of Atmos Energy Corporation to Establish PRP Rider Rates for the Twelve Month Period Beginning October 1, 2024* (Ky. PSC July 31, 2024).

service provided in the field, we also continue to make investments in new technology. Technology is a strategic investment that will enable us to continue improving our business processes, hold down operating costs, and meet the changing expectations of our customers. The removal of the current caps on capital for both non-PRP and PRP, as formally requested by the Company in this Case, is critical for the Company to continue to make these needed investments in safety, reliability, public improvement, and economic development.

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR SHARED (ALLOCABLE) INVESTMENT (KENTUCKY/MID-STATES GENERAL OFFICE AND SHARED SERVICES)?

A. The FY2025 capital budget for allocable investment was developed as part of the Company's normal annual budget cycle which is described later in my testimony.

Q. HOW WAS THE TEST PERIOD ACCUMULATED DEPRECIATION PROJECTED?

A. I began with actual per books accumulated depreciation, adjusted to remove PRP investments as discussed above, as of June 2024 including allocations as discussed by Ms. Wiebe in her testimony. For the months of July 2024 through the end of the Test Period, I added projected depreciation expenses (described later in my testimony) and deducted the same retirements that were projected for gross plant.

Q. DID YOU INCLUDE CONSTRUCTION WORK IN PROGRESS ("CWIP") IN THE RATE BASE?

A. No. The Commission disagreed with inclusion of CWIP in the final Order in Case No. 2018-00281[4] and thus direct and allocated CWIP have been removed from rate base.

Q. HOW DID YOU DETERMINE THE AMOUNT OF TEST PERIOD CASH WORKING CAPITAL ALLOWANCE TO INCLUDE IN RATE BASE?

A. The Company's Cash Working Capital requirement is sponsored by Company witness Joe Christian.

Q. HOW WAS THE TEST PERIOD AMOUNT OF MATERIAL AND SUPPLIES DETERMINED?

A. I calculated the 13-month average amount of materials and supplies for the forecasted Test Period using average actual balances recorded in the six months of actuals included in the Base Period (January - June 2024). The Company does not anticipate a significant change in the amount of materials and supplies in the Test Period. The calculation method maintains the historic level of materials and supplies while smoothing out any historic month to month fluctuations.

[4] Final Order of Case No. 2018-00281, Page 26.

Q. HOW WAS THE AMOUNT OF GAS IN STORAGE DETERMINED?

A. The projected amount of gas in storage is discussed in Mr. Thomas Troup's testimony.

Q. HOW DID YOU PROJECT THE AMOUNT OF TEST PERIOD CUSTOMER ADVANCES FOR CONSTRUCTION?

A. I calculated the amount of customer advances in the forecasted Test Period using average actual balances recorded in the six months of actuals included in the Base Period (January - June 2024). The Company does not anticipate a significant change in the amount of customer advances in the Test Period. The calculation method maintains the historic level of customer advances while smoothing out any historic month to month fluctuations.

Q. DID YOU PROPOSE ANY ADJUSTMENTS FOR ANY REGULATORY ASSETS AND LIABILITIES?

A. Yes. The only regulatory liability included in rate base is the 13-month average of the projected unamortized balance of the protected excess deferred income tax liability discussed in Section IX of my testimony and in the testimony of Mr. Joel Multer. There are no regulatory assets included in rate base in this case. While I have included the amortization expense associated with the rate case expenses anticipated for this proceeding and the amortization of the regulatory liability related to phasing in depreciation rates that was established in the final Order in

Case No. 2018-00281 and continued in Case No. 2021-00214, I have not included the unamortized balances of these items in rate base consistent with the final Order in Case No. 2021-00214.

Q. DID YOU MAKE ANY OTHER RATE BASE ADJUSTMENTS?

A. Yes. As discussed in more detail in the Direct Testimony of Company witness Emily B. Wiebe, an adjustment was made to forecasted plant in service to include the per book balances at June 30, 2024 of the allocated implementation costs for cloud computing projects.

Q. DOES THE COMPANY'S RATE FILING REFLECT A PROJECTION OF ACCUMULATED DEFERRED INCOME TAX ("ADIT")?

A. Yes. ADIT balances are projected in a manner consistent with the Final Order in Case No. 2021-00214. Company witness Joel Multer discusses and supports the forecast of ADIT in his testimony.

V. O&M BUDGETING PROCESS

Q. WHAT ARE THE OBJECTIVES OF THE COMPANY'S O&M BUDGETING PROCESS?

A. The objectives of the Company's O&M budgeting process are to: (1) formalize the process of identifying the anticipated costs of operating and maintaining Atmos Energy's systems each year; (2) ensure that all policies and procedures associated with the annual budgeting process are consistently adhered to by the functional managers and officers; (3) assess the appropriateness of routine maintenance

requirements and non-capital expenditures proposed by the functional managers and officers to ensure that the amounts are adequate to deliver safe, reliable and efficient natural gas service to the Company's customers; and (4) ensure that the O&M budget properly reflects our strategic operational and financial plans. These objectives are applicable to the Company as a whole as well as to its various division, state and local level operations.

Q. CAN YOU DESCRIBE THE COMPANY'S O&M BUDGETING PROCESS?

A. Yes. O&M costs are budgeted on a fiscal year basis, which begins on October 1 of each year (consistent with the seasonal operations of our business) and runs through September 30 of the following year. Preparation of operating and construction budgets for a fiscal year formally begins in late May of each year and culminates with completion of final budgets in late August, just prior to the beginning of the fiscal year. Budget preparation is based on meeting the four objectives described above. Budgets are approved at multiple levels beginning with supervisors/managers up through division leadership. Additional reviews are performed by corporate executive operations management and their staff. High level reviews of the division budgets are also performed by the Company's senior executives who are presiding members of the Company's Management Committee. The Board of Directors must review and approve the total Company budget before

finalization and implementation. This approval typically occurs in September of each year.

Q. WHAT ROLE DOES THE O&M BUDGETING PROCESS PLAY IN THE COMPANY'S FINANCIAL PLANNING?

A. Atmos Energy's Business Planning and Analysis Department ("Business Planning and Analysis") is responsible for financial planning at the enterprise level. That department receives direction from the Board of Directors concerning forward-looking financial objectives for the Company. Business Planning and Analysis is responsible, with significant input and collaboration from division leadership, for translating those enterprise targets into a financial plan for each division and rate jurisdiction. It is the collaboration between Business Planning and Analysis and division leadership that ensures that all four of the objectives described above are met each year. Spending targets are established as a result of this collaboration.

Q. SO FAR YOU HAVE DESCRIBED THE O&M BUDGETING PROCESS, CAN YOU EXPLAIN HOW THE BUDGET IS PREPARED WITHIN THE PARAMETERS OF THIS PROCESS?

A. Yes. The O&M budget is prepared by type of cost element, such as labor, benefits, transportation, rents, office supplies, etc. Within each cost element we budget expenses at the sub-account level. The prior year's actual costs, year-to-date actual costs and budgeted costs for the remainder of the fiscal year are used as guidelines

for budgeting by functional managers and officers. The budgets are prepared using a web-based software tool called Anaplan. This tool allows cost center owners to enter their budgets and for management to review budgets using a number of standard and *ad hoc* reports.

Q. ARE THESE BUDGETS PREPARED BY FEDERAL ENERGY REGULATORY COMMISSION ("FERC") ACCOUNT?

A. No. FERC accounts do not provide a sufficient level of detail to enable the Company to understand the costs within each account. For budgeting purposes (and subsequent managing of expenses), we need more individualized expense types that relate to the operation of each cost center. FERC accounts do not provide that level of detail. However, we do identify our expenditures by FERC account as well as expense type. This provides a timely analysis of the type of charges being expensed by FERC account.

Q. HOW DOES ATMOS ENERGY CONVERT ITS O&M BUDGET BY COST ELEMENT INTO FERC ACCOUNTS?

A. To convert our budget and forecast to FERC accounts, prior year actual expenditures are downloaded from the general ledger by FERC account and cost element. A calculation is then made to determine within each cost element type the percentage of spending attributable to each FERC account. Each percentage factor was then applied to the fiscal year 2025 budget and test period forecast by cost type to develop a budget and Test Period forecast by FERC account.

VI. CONTROL AND MONITORING PROCESSES

Q. DOES THE COMPANY EMPLOY ANY METHODOLOGY TO MONITOR AND CONTROL O&M ACCORDING TO BUDGETED LEVELS?

A. Yes. Atmos Energy utilizes variance monitoring to ensure financial quality control of O&M expenses by formalizing the analysis of variances by cost type and cost center. On a quarterly basis, the Company's Management Committee hosts a meeting with Company Utility Operations, SSU department heads, select Board of Directors members and external auditors at a formal Quarterly Performance Review. Financial and operating results are reviewed for the latest quarter and year-to-date. The goal is to keep all levels of management informed of O&M spending in comparison to budgeted amounts, in order to allow management to react to unanticipated events on a timely basis.

Q. ARE O&M VARIANCES EVALUATED MORE FREQUENTLY THAN ON A QUARTERLY BASIS?

A. Yes. The Kentucky Mid-States Division Finance Department conducts a thorough review of O&M actuals to budget variances each month.

Q. PLEASE DESCRIBE THE MONTHLY VARIANCE REVIEW PROCESS.

A. The process begins by examining, at the Division level, significant variances by cost type (labor, benefits, materials, rents, etc.). Significant variances are researched until an explanation is found. Reasonable explanations could include events that affected the entire Division or a particular cost center or region. In some

cases, clarifying information is sought from cost center owners to explain unusual variances or transactions. For some cost types, clarifying analysis is provided by SSU departments. If errors are found, they are most often corrected in the current month's business. Occasionally, however, errors are discovered after the books are closed, and, depending on materiality, they are corrected in the following month's business.

Q. DOES ANYONE ELSE WITHIN THE DIVISION HAVE THE ABILITY TO MONITOR OR REVIEW O&M VARIANCES?

A. In addition to the research conducted by the Division Finance Department, each cost center owner has the ability to run variance reports throughout the monthly closing process. Because cost center owners are held accountable for significant variances to budget, they conduct their own research and often contact the Division Finance Department when they find errors or have questions about the expenses that were charged to their cost centers.

Q. WHAT CONTROLS AND REPORTING ARE INVOLVED IN THE MONTHLY CLOSE PROCESS REGARDING O&M VARIANCES?

A. Once the monthly books are closed, the SSU Financial Reporting department in Dallas publishes (electronically) the monthly Atmos Energy Financial Package. This package details the financial performance for Atmos Energy at the corporate and division level. For each division, the report includes a comparative income

statement, operating statistics (volumes, total spending), and other financial details. At the end of each quarter, narrative comments are provided by Division officers to describe quarterly and YTD variances. Once complete, this Financial Package is available to all Atmos Energy officers and Board members for review and is an official Sarbanes-Oxley control document of the Company. On a quarterly basis, once the package is complete, an online questionnaire generated by our Sarbanes-Oxley Compliance Tool is completed certifying that the Division Finance Department has conducted a thorough review of the Division's financial performance and the Financial Package and all matters addressed therein. The Company's external auditors look for this certification as evidence of Sarbanes-Oxley compliance.

After meeting the Financial Package control requirement, the Division Finance Department publishes (electronically) detailed O&M reports that include monthly and YTD variances for each cost center and these reports are then made available to each cost center owner and their respective managers (managers, Division Vice Presidents, and the Division President). This activity ensures that each cost center owner receives the same information in the same format each month in a timely fashion in order to make operational decisions and manage our operations effectively and efficiently.

Q. HAS THE O&M VARIANCE MONITORING AND CONTROL PROCESS YOU HAVE DESCRIBED ENABLED KENTUCKY TO OPERATE REASONABLY WITHIN ITS BUDGET EACH YEAR?

A. Yes. While the table below indicates some overage in 2018 and 2019, overall, the Company's actual O&M expenditures over the past eleven years in Kentucky have tracked closely to overall budgeted amounts or shows that conscious mid-year decisions were made to vary from budget rather than reduce important ongoing O&M.

Fiscal Year	Actual $	Budget $	Over/(Under) $	Variance %
2023	$32,293	$31,617	$676	2.14%
2022	$30,444	$30,851	($407)	-1.32%
2021	$32,232	$31,551	$681	2.16%
2020	$29,553	$29,830	($277)	-0.93%
2019	$31,589	$29,287	$2,302	7.86%
2018	$29,222	$27,463	$1,758	6.40%
2017	$27,511	$27,657	($146)	-0.53%
2016	$27,496	$26,191	$1,305	5.00%
2015	$27,922	$26,762	$1,160	4.30%
2014	$26,515	$26,804	($289)	-1.10%
2013	$25,509	24,913	$596	2.40%

Q. DO YOU HAVE AN OPINION REGARDING THE SIGNIFICANCE OF THE HISTORICAL DATA REFLECTED IN THE TABLE ABOVE?

A. Yes. I examined what drove the variances in 2018 and 2019 and am satisfied that in conjunction with overall corporate results, O&M objectives continued to be met. Said another way, the Division communicated unplanned O&M needs and senior

management concurred to adjust planned O&M spending rather than make cuts to meet that year's direct O&M budget. As can be seen in the past several fiscal years, despite COVID and the uncertainty regarding the pandemic the O&M budget was within approximately 2%.

Q. WHY IS THAT IMPORTANT?

A. This data demonstrates that the Company's budgeting and control processes I have described form a reasonable basis for purposes of the Company's forecasted Test Period O&M budget in this rate proceeding.

Q. WHAT ARE THE GOALS OF THE COMPANY'S PROCESS OF CONTROLLING AND MONITORING CAPITAL EXPENDITURE VARIANCES?

A. Variances from budgeted amounts are inherent in the process of making capital expenditures. Our variance monitoring process exists to institute financial quality control by formalizing the analysis of variances by budget category and responsibility center in a process that identifies year-to-date spending variances. The goal is to keep all levels of management informed of spending by category and responsibility center relative to budgeted levels and to ensure that corrective action is initiated on a timely basis. This supports decision-making related to the cost and appropriate management of current and future capital projects.

Q. PLEASE DESCRIBE THE COMPANY'S PROCESS FOR CONTROLLING AND MONITORING CAPITAL EXPENDITURE VARIANCES.

A. The Company's process for controlling and monitoring capital expenditure variances is utilized by each operating division as well as by Shared Services. At the division level the Company's capital budgeting system maintains projects in two broad categories - Blanket Functionals and Specific Projects. The Blanket Functionals include total capital authorizations of a similar type such as new services, leak repair, short main replacements, small integrity/reliability projects, etc. Specific projects are uniquely identified such as a specific highway relocation project, replacement of work equipment, or some larger significant integrity/reliability project.

Once a project has been entered in the capital budget system a request for authorization is submitted. If during the course of a project, field management identifies that the costs of the project will exceed approved amounts, a request for supplemental funding may be submitted. All expenditures above authorized appropriation, as well as expenditures for unbudgeted projects or variances on budgeted and approved projects, must be approved at the appropriate levels within the Company.

In FY2015 the Company began utilizing a monthly capital forecast module through its accounting system PowerPlan. The forecast module is updated

throughout the month by Project Specialists, Operation Supervisors and Operation Managers as known and measurable changes occur. At the end of each month, the forecast for that specific month is updated with actuals and closed to future charges as part of the monthly closing process. Once current month actuals have posted, the Project Specialists, Operations Supervisors and Operations Managers are given two to three days to make final updates to their respective projects. Once complete, the forecasts are reviewed by the Operations Supervisors, Operations Managers and the VP Operations. A final review of the forecast is performed by the division Finance Department. The VP of Finance communicates to the corporate Plant Accounting Department that the forecast is approved. A snapshot of the forecast is then taken by Plant Accounting for archiving. Upon completion of the snapshot the forecast module is reopened for changes as they become known and measurable during the course of the new month.

VII. FORECASTED TEST PERIOD O&M BUDGET

Q. WHAT IS THE FORECASTED TEST PERIOD USED IN THIS RATE APPLICATION?

A. The forecasted Test Period is April 1, 2025 through March 31, 2026.

Q. HOW WAS THE FORECASTED TEST PERIOD BUDGET DEVELOPED?

A. The basis for the forecasted Test Period is the FY2025 budget. Consistent with our normal annual budgeting timelines, this budget was prepared during the summer of 2024 and approved by the Board of Directors in September of 2024. This budget was prepared in the manner I described earlier. The forecasted Test Period includes

the last six months of FY2025 and the first six months of FY2026. I will describe the methodology used for the projection period in detail below. The base period and FY2025 O&M budget and forecasted Test Period projection were converted into FERC account detail using the method described above.

Q. WHAT ARE THE COMPONENTS OF O&M FOR THE FORECASTED TEST PERIOD?

A. The forecasted Test Period O&M is comprised of three parts: expenses incurred and booked directly in Kentucky (rate division 009), allocated expenses from the Division General Office (rate division 091), and allocated expenses from SSU (comprised of rate divisions 002 and 012). I will describe the methodology used for the projection for each of the three components. Please see Exhibit GKW-3 for a comparison of Base Period to Test Period O&M by rate division.

Q. WHAT COMPRISES THE BASE PERIOD LEVEL OF COST FILED IN THIS RATE APPLICATION?

A. The Base Period level of cost is January 1, 2024 through December 31, 2024. It is composed of six months of actual results through June 2024, three months of our FY2024 budget (July – September 2024) and the first three months of our FY2025 budget.

Q. WHAT IS THE DIRECT O&M FOR THE BASE PERIOD?

A. $17,683,099.

Q. WHAT IS THE DIRECT O&M BUDGET FOR THE FORECASTED TEST PERIOD?

A. $16,670,826.

Q. WHAT IS THE DIFFERENCE BETWEEN THE BASE PERIOD O&M AND TEST PERIOD O&M[5]?

A. The difference is a decrease of $1,012,273 and reflects adjustments I have made for labor and benefits, other O&M, bad debt and ratemaking adjustments itemized below.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR LABOR AND BENEFITS.

A. The labor forecast for the forecasted Test Period is based on the Company's approved FY2025 budget. As part of the normal budgeting process, each employee's total salary, expected capital / expense ratio and expected standby and overtime amounts are included. Employee levels are projected to remain relatively constant from the base period to the test period. Base pay increases go into effect each October 1 and averaged 3.5% for the increases that are effective October 1, 2024. These increases are captured as part of the FY2025 budget. An adjustment was made as part of the forecast to account for an average wage increase of 3.5% to become effective October 1, 2025. Overall, direct labor expense is projected to increase $830,469 from the base period to the test period.

[5] Please see Exhibit GKW- 3 for O&M by Cost Element

Benefits are projected as a fixed benefit load percentage of labor expense. The Test Period benefits expense of $852,653 is $106,722 higher than the base period.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO OTHER O&M.

A. Other O&M consists of all expenses except labor, benefits, and bad debt. In filings involving forward looking test periods, the Company normally includes in O&M its most recent budget without adjustments for the months where the budget and Test Period overlap and applies an inflation factor to these O&M categories for months when the forecasted test year extends beyond the Company's budget. However, recognizing the Commission's findings in Case No. 2013-00148,[6] I have not inflated these O&M categories above 2025 budgeted levels in this proceeding.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO BAD DEBT.

A. Our goal is to keep bad debt no higher than 1.00% of residential, commercial and public authority margin. This target is a bit higher than pre-COVID years as the Company continues to feel the impacts of COVID-era rules and challenges on net write-offs. With the exception of complying with rules specific to the COVID-19 Pandemic, the Company works vigorously to work with customers on payment plans and collect bad debts to reduce the impact of bad debt expense on customers.

[6] Case No. 2013-00148, *Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications* (Ky. PSC Apr. 22, 2014) at 16-17.

To arrive at the bad debt projection of $731,532, I calculated 1.00% of residential, commercial and public authority margin from the revenue projection in the direct testimony of Company witness Mr. Thomas Troup. This projection is $1,087,837 lower than the Base Period which continues to reflect the challenges I mentioned above.

Q. DO YOU BELIEVE THAT 1.00% IS A REASONABLE LEVEL TO USE FOR ESTABLISHING RATES IN THIS CASE?

A. I believe that 1.00% is an aggressive goal and we will likely exceed this percentage based on recent net write-off activity; however the Company is willing to hold itself to recovery of this percentage as it anticipates eventually returning to normal historical levels.

Q. WHAT IS THE AMOUNT OF THE DIVISION'S GENERAL OFFICE O&M ALLOCATED TO KENTUCKY FOR THE BASE PERIOD?

A. $ 5,535,304.

Q. WHAT IS THE AMOUNT OF THE DIVISION'S GENERAL OFFICE O&M BUDGET ALLOCATED TO KENTUCKY FOR THE FORECASTED TEST PERIOD?

A. $7,694,358.

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE GENERAL OFFICE BASE PERIOD AND FORECASTED TEST PERIOD AMOUNTS.

A. The difference is an increase of $2,159,054 and reflects adjustments I have made for labor and benefits, and other O&M. The budgeting process and forecast methodologies are identical for both direct O&M and General Office O&M. Therefore, the categories of adjustments made to forecast General Office O&M are also the same as direct.

Q. WHAT IS THE AMOUNT OF SHARED SERVICES O&M ALLOCATED TO KENTUCKY FOR THE BASE PERIOD?

A. $10,318,517.

Q. WHAT IS THE AMOUNT OF THE SHARED SERVICES O&M BUDGET ALLOCATED TO KENTUCKY FOR THE FORECASTED TEST PERIOD?

A. $8,953,541.

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE SHARED SERVICES BASE PERIOD AND FORECASTED TEST PERIOD AMOUNTS.

A. The difference is a decrease of $1,364,977. The SSU budget is prepared in a fashion consistent with that of the Division. Once the SSU department heads complete, submit and get approval for their budgets, the appropriate level of expenses are

allocated to the Kentucky rate jurisdiction per the methodologies described in Ms. Emily Wiebe's testimony.

Q. WHO MONITORS SHARED SERVICES BILLINGS TO THE DIVISION?

A. Shared Services expense billings are reviewed as part of our monthly close process described earlier. The Division Finance Department is then responsible for communications with Financial Reporting in Dallas for explanations of any significant variances.

Q. WHAT IS THE TOTAL FORECASTED TEST PERIOD O&M THAT RESULTS FROM THE SUM OF THE DIRECT, GENERAL OFFICE AND SSU COMPONENTS?

A. $33,318,725.

Q. DO THE FORECASTED O&M AMOUNTS DISCUSSED IN YOUR TESTIMONY INCLUDE THE RATEMAKING ADJUSTMENTS QUANTIFIED ON SCHEDULE C-2?

A. Yes. Schedule C-2 contains eight ratemaking adjustments.

- <u>Adjustment for Sales and Promotional Advertising Expenses</u>

  The first adjustment removes $188,721 of sales and promotional advertising from test year sales expense. It is quantified on Schedule F.4.

- <u>Adjustment for Regulatory Asset Amortization Expenses</u>

The second adjustment adds $214,241 to test year administrative and general expense to account for the three-year amortization of the expected costs pertaining to this case. The amount is quantified on Schedule F.6.

- Adjustment for Expense Report Exclusion

The third adjustment removes $133,963 of certain expense report items from test year administrative and general expense. The Company's goal is to ensure that its Kentucky rates rest upon a sound foundation of unquestionable costs. The Company is committed to achieving that goal even if it means foregoing recovery of a certain amount of legitimate business expense in an effort to ensure that there can be no question about what remains. The expense report exclusion adjustment is made to exclude certain cost items which the Company does not intend to seek recovery from its customers in this case. The excluded amounts are quantified on Schedule F.8 and occur in Kentucky as well as the Division General Office and SSU.

- Adjustment for Incentive Compensation

The fourth adjustment removes the performance portion of incentive compensation expenses associated with all of its employees. This adjustment is $1,112,598. The Company believes incentive compensation is a critical part of the ability to attract and retain employees at competitive market rates, and should be included as a recoverable O&M expense. Atmos Energy is not unique

in making incentive compensation part of the overall compensation package that it provides to its employees. The Company designs its total compensation package to be in the middle of the job market in which we compete for talent. This means that there are as many companies offering total compensation above Atmos Energy's package as there are below it for comparable jobs. It is important to understand that "total compensation" does not represent only base salary, but also includes bonuses, benefits, retirement, etc. Because Atmos Energy falls in the middle of the job market in terms of the overall compensation packages, the Company believes the incentive compensation costs that are a component of this overall compensation package are reasonable and should be recovered as part of revenue requirement. In order to meet the Company's incentive pay criteria, Company employees must work together to ensure that the Company operates efficiently and effectively. Efficient and effective operations translate into lower costs and therefore into lower rates for customers. Strong financial performance for the Company and lower rates for customers are, therefore, not mutually exclusive. However, in recognition of the Commission's precedent on this issue, I have removed this expense in this proceeding for the sole purpose of simplifying the regulatory review process. This adjustment is quantified on Schedule F.10.

- <u>Adjustment for Certain Retirement Plan Expenses</u>

The fifth adjustment removes costs associated with the defined benefit pension for employees who also participate in the Company's 401(k) match. This adjustment is $175,169. While the Company supports the prudency of these costs as part of its comprehensive rewards program for employees, I have removed these costs for the sole purpose of simplifying the regulatory review process in the current rate case proceeding. This adjustment is quantified on Schedule F.11.

- Adjustment for Directors' Stock Expenses

The sixth adjustment removes costs associated with stock awarded to members of the Board of Directors as part of their compensation. This adjustment is $134,473. While the Company supports the prudency of these costs as part of its market competitive compensation package for Directors, I have removed these costs in the same manner in which they were removed from revenue requirement in Case No. 2018-00281 consistent with the Commission's findings and Final Order[7] for the sole purpose of simplifying the regulatory review process in the current rate case proceeding. This adjustment is quantified on Schedule F.11.

- Adjustment for SERP Expenses

The seventh adjustment removes $49,769 in costs associated with SERP

[7] Case No. 2018-00281, Final Order, Page 27.

expense. The Commission noted in Case 2018-00281 that has traditionally denied compensation tied to financial performance standards. The Company's SERP expense is based on a combination of base salary and annual bonus expense therefore is partially based on performance (Performance Share awards and MIP payments) therefore these expenses along with the associated ADIT items have been removed from the case. This adjustment is quantified on Schedule F.9

- Adjustment for Lobbying Activities

The eighth adjustment removes $12,590 in costs associated with lobbying activities that are included on invoices paid by the Company to the American Gas Association and Kentucky Chamber of Commerce. This adjustment is quantified on Schedule F.1.

In addition to the adjustments listed here and accounted for on Schedule C.2, I made an adjustment to the FY 2025 budget for SSU (rate divisions 002 and 012) to remove from O&M the budgeted expense associated with the cloud computing assets that I discussed in section IV of my testimony. For further discussion of the Company's proposal for cloud computing, please see the testimony of Emily B. Wiebe.

Q. OTHER THAN THE LOBBYING ADJUSTMENT IDENTIFIED ABOVE, ARE THERE ANY OTHER EXPENSES FOR LOBBYING RELATED ACTIVITIES INCLUDED IN THIS FILING?

A. No. The Company uses external contractors for lobbying activities, and those expenses are coded to account 4264 and recorded below the line. Please see Schedule F-7 for a summary of these expenses and please also see the testimony of Mr. Taylor.

Q. DO YOU BELIEVE THAT THE FORECASTED TEST PERIOD O&M BUDGET YOU HAVE PRESENTED IS THE MOST REASONABLE ESTIMATE OF COSTS FOR THE TEST PERIOD USED IN THIS PROCEEDING?

A. Yes. It is the best estimate we have of the Kentucky jurisdiction's future operating and maintenance expenses.

VIII. DEPRECIATION EXPENSE AND TAXES OTHER THAN INCOME TAXES

DEPRECIATION EXPENSE

Q. WHAT IS THE DEPRECIATION EXPENSE FOR THE BASE PERIOD?

A. The amount of depreciation expense for the Base Period is $19,915,761.

Q. WHAT IS THE DEPRECIATION EXPENSE FOR THE FORECASTED TEST PERIOD?

A. The amount of depreciation expense for the forecasted Test Period is $22,028,375.

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE BASE PERIOD AND FORECASTED TEST PERIOD DEPRECIATION AMOUNTS.

A. I used currently approved depreciation rates for plant accounts related to Kentucky direct investments. Company witness Ned Allis supports proposed depreciation rates for shared assets in the Division General Office and Shared Services which I used beginning on the first day of the Test Period. The appropriate depreciation rates are applied to the applicable categories of plant for the Kentucky jurisdiction and allocable assets, resulting in total depreciation expense. The amounts allocated from the General Office and SSU to Kentucky are based upon the cost allocation methodology more fully described in Ms. Emily Wiebe's testimony.[8]

Q. YOU MENTIONED THE DEPRECIATION REGULATORY LIABILITY IN A PREVIOUS QUESTION AND ANSWER, WHAT IS THE DEPRECIATION REGULATORY LIABILITY?

A. The Final Order in Case No. 2018-00281, Page 59, Ordering Paragraph No. 5 states, "Atmos shall establish a regulatory liability in the amount of $3,676,784 for the remainder of the reduction in depreciation expense, the amortization of which will be addressed in Atmos's next base rate case." The Company understood the $3,676,784 to be an annual amount and therefore divided by 12 and began recording a regulatory liability entry on a monthly basis for $306,399 beginning in May of

[8] Please see Exhibit GKW-2 Allocation Factors

2019. That monthly entry continued until the conclusion of Case No. 2021-00214. The order in that case prescribed a six-year amortization of the balance which resulted in amortization of $136,978 per month. Schedule F-12 details the monthly amortization and balance beginning with the beginning of the Base Period in this case. The resulting balance at the beginning of the Test Period will be $6,565,552.

Q. HOW DOES THE COMPANY PROPOSE TO RETURN THIS TO THE CUSTOMER?

A. The Company proposes to return the full amount over a three-year period beginning with the implementation of rates in this case. The resulting amortization will be $182,376 per month or $2,188,517 per year. That amount reduces the amount of the revenue deficiency in this case and is included in the Company's proposed increase of $33,001,164.

<u>TAXES OTHER THAN INCOME TAXES</u>

Q. WHAT IS THE EXPENSE LEVEL FOR TAXES, OTHER THAN INCOME TAXES FOR THE BASE PERIOD?

A. $12,842,195.

Q. WHAT IS THE LEVEL OF TAXES, OTHER THAN INCOME TAXES FOR THE FORECASTED TEST PERIOD?

A. $13,731,224.

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE BASE PERIOD AND FORECASTED TEST PERIOD.

A. The difference is an increase of $889,029. The components are itemized by type of tax on Schedule C.2.3 F. For the last six months of the forecasted Test Period, payroll taxes have been escalated from the FY2025 budget to account for base pay increases consistent with my labor forecast. The monthly accrual for the Public Service Commission Assessment is based on the assessment rate and projected Test Period revenues. The DOT transmission user tax has been held constant from the Base Period. The Company's methodology for forecasting ad valorem expense is consistent with the previous case. That methodology develops an historical ratio of ad valorem expense to plant and applies the ratio to projected levels of plant for the Forecasted Test Period. The amount of taxes allocated from the Division General Office and SSU is based on the allocation methodologies discussed in the Cost Allocation Manual.

IX. INCOME TAXES

Q. HOW DO INCOME TAXES IMPACT BASE RATES TO CUSTOMERS?

A. There are currently two main types of rate impacts (1) ongoing statutory income tax expense and (2) a return of the liability for federal excess deferred income taxes.

Q. WHAT ARE THE STATUTORY INCOME TAX RATES UTILIZED BY THE COMPANY IN THIS CASE?

A. The Company's rates current and proposed rates reflect a 21% federal statutory rate and a 5% Kentucky state income tax rate. Because state taxes are deductible from

federal income tax purposes, the blended income tax rate is 24.95%.

Q. HOW IS TAX EXPENSE CALCULATED IN THE CURRENT FILING?

A. Tax expense is calculated by applying statutory tax rates to the forecasted return to arrive at required operating income, as shown on Schedule C.1.

Q. PLEASE PROVIDE AN UPDATE ON THE CURRENT STATUS OF THE COMPANY'S EDITL IN THIS PROCEEDING FOLLOWING CASE NO. 2021-00214.

A. In Case No. 2021-00214, the Company proposed that the return of unprotected EDITL be over a five-year period beginning with the implementation of rates in that case and included the accelerated EDIT amortization in development of base rates.[9] In its final Order in 2021-00214, the Commission decided on a three-year amortization period for the return of unprotected EDIT and this amount is currently reflected in the Company's base rates.[10] The three-year amortization of the unprotected EDITL will be complete after May 2025.

Q. IS THE EXPIRATION OF THE AMORTIZATION OF THE UNPROTECTED EDITL ONE OF THE REASONS FOR THE FILING OF THIS CASE?

[9] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022) final Order at 20.
[10] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022) final Order at 21.

A. Yes. In its motion for rehearing in Case No. 2021-00214 the Company proposed a rider to reflect the amortization of the unprotected EDITL as the end of the three-year amortization period may not align with the date of a subsequent rate case.[11] The Commission denied the Company's proposal on rehearing and stated that "Atmos has the opportunity to file a new application for base rates within three years such that the amortization could be adjusted at that point if necessary."[12] The proposed rates supported by Mr. Troup for the Test Period account for the expiration of the unprotected EDITL. Because the Test Period in the case begins two months prior to that expiration, the Company proposes to refund the final two months' unprotected EDITL amortization to customers via a one-time bill credit.

Q. HAS THE COMPANY FURTHER ADJUSTED THE AMOUNT OF EDITL AND EDITL AMORTIZATION IN THIS PROCEEDING?

A. Yes. Please see the testimony of Company witness Joel Multer for further discussion. The EDITL balance and amortization in this case is shown on WP B.5.F1.

[11] *See* Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC June 24, 2022) Order at 3.
[12] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC June 24, 2022) Order at 4.

X. CONCLUSION

Q. DO YOU BELIEVE THAT THE FORECASTED TEST PERIOD COST OF SERVICE COMPONENTS YOU HAVE PRESENTED REPRESENT THE MOST REASONABLE ESTIMATE OF COSTS FOR THE TEST PERIOD USED IN THIS PROCEEDING?

A. Yes. The cost of service forecast is the best projection of the Company's future cost of service. The expenses and investments for which the Company seeks recovery have been prudently budgeted and will be prudently incurred.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Gregory K. Waller, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Gregory K. Waller

STATE OF TEXAS

COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Gregory K. Waller on this the 23rd day of September, 2024.

Notary Public

My Commission Expires: September 1, 2028

Giselle R Heroy
My Commission Expires
9/1/2028
Notary ID130804842

Gregory K. Waller

Testimony and Rate Case Management Experience
Exhibit GKW-1

Sponsor	Date	Docket/Case No.	Subject
Regulatory Commission of Alaska			
Cook Inlet Natural Gas Storage Alaska	2020	U-20-012	Annual Mechanism and Formula Rate Plan
Georgia Public Service Commission			
Atmos Energy Corporation	2012	36278	Sale of jurisdiction
Atmos Energy Corporation	2012	34734	GRAM (annual mechanism) filing
Atmos Energy Corporation	2011	34734	Application for Georgia Rate Adjustment Mechanism ("GRAM") annual mechanism
Atmos Energy Corporation	2009	30442	General Rate Case; Operating expense forecast and budgeting process
Atmos Energy Corporation	2009	29554	Gas Supply Plan; Potential sale of LNG facility
Atmos Energy Corporation	2008	27163	General rate case; Operating expense forecast and budgeting process
Kentucky Public Service Commission			
Atmos Energy Corporation	2019	2019-00253	Annual Pipe Replacement Program (PRP) filing
Atmos Energy Corporation	2018	2018-00281	General rate case
Atmos Energy Corporation	2017	2017-00308	Annual Pipe Replacement Program (PRP) filing
Atmos Energy Corporation	2017	2017-00349	General rate case and petition for Annual Rate Review Mechanism
Atmos Energy Corporation	2016	2016-00262	Annual Pipe Replacement Program (PRP) filing
Atmos Energy Corporation	2015	2015-00272	Annual Pipe Replacement Program (PRP) filing
Atmos Energy Corporation	2015	2015-00343	General rate case
Atmos Energy Corporation	2014	2014-00274	Annual Pipe Replacement Program (PRP) filing
Atmos Energy Corporation	2013	2013-00148	General rate case
Atmos Energy Corporation	2013	2013-00304	Annual Pipe Replacement Program (PRP) filing
Atmos Energy Corporation	2009	2009-00354	General rate case and petition for annual infrastructure (PRP) mechanism
Atmos Energy Corporation	2006	2006-00464	General rate case
Louisiana Public Service Commission			
Atmos Energy Corporation	2019	U-35153	LA Gas Service (LGS) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2019	U-35106	Trans LA (TLA) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2018	U-34803	LA Gas Service (LGS) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2018	U-34714	Trans LA (TLA) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2017	U-34424	LA Gas Service (LGS) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2017	U-34343	Trans LA (TLA) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2016	U-34028	LA Gas Service (LGS) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2016	U-33925	Trans LA (TLA) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2015	U-28814	LA Gas Service (LGS) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2015	U-32987	Trans LA (TLA) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2014	U-28814	LA Gas Service (LGS) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2014	U-32987	Trans LA (TLA) Rate Stabilization (RSC) Filing

Gregory K. Waller

Testimony and Rate Case Management Experience
Exhibit GKW-1

Sponsor	Date	Docket/Case No.	Subject
Atmos Energy Corporation	2013	U-32987	Application for modification of RSC tariffs (establish system integrity program)
Atmos Energy Corporation	2013	U-28814	LA Gas Service (LGS) Rate Stabilization (RSC) Filing
Atmos Energy Corporation	2013	U-28814	Trans LA (TLA) Rate Stabilization (RSC) Filing
Mississippi Public Service Commission			
Atmos Energy Corporation	2019	2005-UN-0503	Annual Stable Rate Filing
Atmos Energy Corporation	2019	2015-UN-049	System Integrity Rider
Atmos Energy Corporation	2018	2005-UN-0503	Annual Stable Rate Filing; eliminate earnings band
Atmos Energy Corporation	2018	2015-UN-049	System Integrity Rider
Atmos Energy Corporation	2017	2005-UN-0503	Annual Stable Rate Filing; narrow earnings band; actual capital structure
Atmos Energy Corporation	2017	2015-UN-049	System Integrity Rider
Atmos Energy Corporation	2016	2005-UN-0503	Annual Stable Rate Filing
Atmos Energy Corporation	2016	2015-UN-049	System Integrity Rider
Atmos Energy Corporation	2015	2005-UN-0503	Annual Stable Rate Filing
Atmos Energy Corporation	2015	2015-UN-049	Application for System Integrity Rider
Atmos Energy Corporation	2014	2005-UN-0503	Annual Stable Rate Filing
Atmos Energy Corporation	2013	2005-UN-0503	Annual Stable Rate Filing; ROE improvement
New York Department of Public Service			
Liberty Utilities	2023	23-W-0235	Revenue Requirements
Public Utilities Commission of Nevada			
Southwest Gas Corporation	2021	21-09001	Revenue Requirements
Southwest Gas Corporation	2020	20-02023	Revenue Requirements
Tennessee Public Utility Commission			
Atmos Energy Corporation	2019	19-00018	Annual Review Filing
Atmos Energy Corporation	2019	19-00076	Annual Review Reconciliation
Atmos Energy Corporation	2018	18-00067	Annual Review Filing
Atmos Energy Corporation	2018	18-00097	Annual Review Reconciliation
Atmos Energy Corporation	2018	18-00034	Impact of Tax Cuts and Jobs Act
Atmos Energy Corporation	2018	18-00112	Investigation into possible modifications to Annual Review mechanism
Atmos Energy Corporation	2017	17-00012	Annual Review Filing
Atmos Energy Corporation	2017	17-00091	Annual Review Reconciliation
Atmos Energy Corporation	2016	16-00013	Annual Review Filing
Atmos Energy Corporation	2016	16-00105	Annual Review Reconciliation
Atmos Energy Corporation	2014	14-00081	Petition for Annual Rate Review Mechanism
Atmos Energy Corporation	2014	14-00146	General rate case and petition for Annual Rate Review Mechanism
Atmos Energy Corporation	2012	12-00064	General rate case
Atmos Energy Corporation	2008	08-00197	General rate case

Gregory K. Waller

Testimony and Rate Case Management Experience
Exhibit GKW-1

Sponsor	Date	Docket/Case No.	Subject
Atmos Energy Corporation	2007	07-00105	General rate case
Atmos Energy Corporation	2007	07-00081	Environmental cost recovery rider
Atmos Energy Corporation	2006	05-00258	Show Cause initiated by Tennessee Regulatory Authority
Virginia State Corporation Commission			
Atmos Energy Corporation	2019	2019-00010	Annual Information Filing (AIF)
Atmos Energy Corporation	2019	2019-00054	Application for second SAVE plan (safety infrastructure rider)
Atmos Energy Corporation	2018	2018-00014	General rate case
Atmos Energy Corporation	2017	2017-00009	Annual Information Filing (AIF)
Atmos Energy Corporation	2017	2017-00081	SAVE (safety infrastructure rider) filing
Atmos Energy Corporation	2016	2015-00119	Expedited rate case
Atmos Energy Corporation	2016	2016-00057	SAVE (safety infrastructure rider) filing
Atmos Energy Corporation	2015	2015-00002	Annual Information Filing (AIF)
Atmos Energy Corporation	2015	2015-00064	SAVE (safety infrastructure rider) filing
Atmos Energy Corporation	2014	2013-00124	Expedited rate case
Atmos Energy Corporation	2014	2014-00044	SAVE (safety infrastructure rider) filing
Atmos Energy Corporation	2013	2013-00006	Annual Information Filing (AIF)
Atmos Energy Corporation	2013	2013-00068	SAVE (safety infrastructure rider) filing
Atmos Energy Corporation	2008	2008-00007	Expedited rate case

Effective October 1, 2023
ATMOS ENERGY CORPORATION
Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/23

	ALL COMPANIES		**30**	**60**	**20**	**20**	**50**	**70**	**80**	**180**
	A. Composite Allocation Factor:	Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	Kentucky/ MidStates Div	Mississippi Div	Mid-Tex Div	Atmos P/L
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**	**(j)**
1	Gross Direct PP&E	**22,193,333,978**	1,486,022,704	942,787,207		1,635,556,907	1,905,675,223	1,198,494,628	9,401,118,962	5,556,555,135
2	Average Number of Customers	**3,349,562**	317,188	270,532		361,942	364,995	249,428	1,784,960	293
3	Total O&M Expense *	**583,390,525**	39,961,803	35,737,713		38,928,875	46,118,707	39,279,343	208,717,061	171,814,702
4	(* w/o Allocation)									
5										
6	Gross Direct PP&E	**100.01%**	**6.69%**	**4.25%**	**0.00%**	**7.37%**	**8.59%**	**5.40%**	**42.36%**	**25.04%**
7	Average Number of Customers	**100.00%**	**9.45%**	**8.08%**	**0.00%**	**10.81%**	**10.90%**	**7.45%**	**53.29%**	**0.01%**
8	Total O&M Expense	**100.00%**	**6.83%**	**6.13%**	**0.00%**	**6.67%**	**7.91%**	**6.73%**	**35.78%**	**29.45%**
9										
10	**Total Composite Factor for FY 2024**	**100.00%**	**7.66%**	**6.15%**	**0.00%**	**8.28%**	**9.13%**	**6.53%**	**43.81%**	**18.17%**
11										
12										

		220	**232**	**234**	**303**	
13						
14		**AELIG**	**UCGS-Barnsley**	**TLGS**	**TLGP**	**Remaining non reg**
15						
16	Gross Direct PP&E	5,174,282	13,058,627	8,480,855	23,739,881	16,669,567
17	Average Number of Customers	218	-		6	-
18	Total O&M Expense *	984,095	206,246	554,928	869,007	218,045
19	(* w/o Allocation)					
20						
21	Gross Direct PP&E	**0.02%**	**0.06%**	**0.04%**	**0.11%**	**0.08%**
22	Average Number of Customers	**0.01%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
23	Total O&M Expense	**0.17%**	**0.04%**	**0.10%**	**0.15%**	**0.04%**
24						
25	**Total Composite Factor for FY 2024**	**0.07%**	**0.03%**	**0.05%**	**0.09%**	**0.04%**

Atmos Energy Corporation
Atmos Energy Mid States Div
Development of Allocation Factors
Effective October 1, 2023

Line #	Div #	Division Name	Sept ' 23 Direct Property Plant & Equipment	Percent of MidStates Property	Sept '23 Total O&M w/o 922	Percent of MidStates O&M	Sept '23 Avg Number of Customers	Percent of MidStates Customers	**MidStates Allocation Percent**
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(j)**
1									
2	09	KENTUCKY	906,057,759	47.59%	17,742,574	52.88%	180,549	49.46%	49.97%
3	93	TENNESSEE	862,690,255	45.31%	12,647,344	37.69%	160,294	43.92%	42.31%
4	96	VIRGINIA	135,153,085	7.10%	3,164,821	9.43%	24,152	6.62%	7.72%
5									
6									
7		Total	1,903,901,099	100%	33,554,739	100%	364,995	100%	100%

Exhibit GKW-3
O&M by Cost Element

	Kentucky			SSU			Division General Office			Total		
	Base	Test	Difference	Base	Test	Difference	Base	Test	Difference	Base	Test	Difference
Labor	$ 6,309,802	$ 7,140,271	$ 830,469	$ 4,739,512	$ 5,326,025	$ 586,513	$ 1,454,100	$ 1,603,731	$ 149,631	$ 12,503,414	$ 14,070,026	$ 1,566,612
Benefits	745,931	852,653	106,722	1,226,626	1,486,382	259,756	807,171	1,569,220	762,049	2,779,729	3,908,255	1,128,526
Employee Welfare	169,922	161,613	(8,310)	1,934,571	1,629,527	(305,045)	435,911	331,803	(104,108)	2,540,404	2,122,942	(417,462)
Insurance	37,513	-	(37,513)	2,690,464	2,935,530	245,065	47,568	93,109	45,540	2,775,546	3,028,638	253,092
Rent, Maint., & Utilities	1,011,281	1,048,417	37,136	439,892	427,626	(12,266)	185,439	277,952	92,513	1,636,612	1,753,994	117,382
Vehicles & Equip	1,218,461	1,391,358	172,896	11,426	12,502	1,076	56,565	81,858	25,293	1,286,452	1,485,717	199,265
Materials & Supplies	1,065,284	1,031,735	(33,549)	69,777	63,927	(5,849)	23,864	29,362	5,498	1,158,925	1,125,025	(33,900)
Information Technologies	39,333	24,219	(15,114)	2,081,231	2,137,856	56,625	105,383	142,362	36,980	2,225,946	2,304,437	78,491
Telecom	102,681	114,100	11,419	243,225	225,090	(18,135)	116,995	182,781	65,786	462,901	521,971	59,070
Marketing	213,629	111,748	(101,881)	36,962	14,161	(22,802)	359,448	475,637	116,189	610,039	601,546	(8,494)
Directors & Shareholders &PR	-	-	-	349,569	326,864	(22,705)	1,164	-	(1,164)	350,734	326,864	(23,869)
Dues & Donations	123,784	119,535	(4,249)	63,521	58,582	(4,939)	56,725	103,523	46,798	244,030	281,640	37,610
Print & Postages	13,123	32,894	19,771	26,562	28,208	1,646	7,635	5,753	(1,882)	47,320	66,854	19,535
Travel & Entertainment	385,894	388,077	2,183	117,187	108,481	(8,706)	310,851	342,033	31,183	813,932	838,591	24,659
Training	48,646	56,366	7,721	75,199	85,745	10,546	86,608	117,458	30,850	210,453	259,569	49,116
Outside Services	4,434,995	3,203,185	(1,231,810)	1,603,567	1,086,308	(517,258)	1,535,974	2,734,761	1,198,787	7,574,536	7,024,254	(550,282)
Provision for Bad Debt	1,603,608	731,532	(872,076)	215,082	-	(215,082)	679	-	(679)	1,819,369	731,532	(1,087,837)
Miscellaneous	159,210	252,754	93,544	(5,605,856)	(5,803,238)	(197,382)	(56,775)	10,394	67,169	(5,503,422)	(5,540,090)	(36,669)
Total O&M Expenses	**$ 17,683,099**	**$ 16,660,457**	**$ (1,022,642)**	**$ 10,318,517**	**$ 10,149,574**	**$ (168,943)**	**$ 5,535,304**	**$ 8,101,735**	**$ 2,566,431**	**$ 33,536,921**	**$ 34,911,766**	**$ 1,374,846**
RateMaking Adjustments:												
Advertising Adjustments		(157,821)	(157,821)		(11,659)	(11,659)		(19,242)	(19,242)		(188,721)	(188,721)
Club Expenses		(12,590)	(12,590)			-			-		(12,590)	(12,590)
Expense Report Exclusions		(33,461)	(33,461)		(49,096)	(49,096)		(51,406)	(51,406)		(133,963)	(133,963)
SERP Expense			-		(31,836)	(31,836)		(17,933)	(17,933)		(49,769)	(49,769)
Regulatory Asset Amortizations		214,241	214,241			-			-		214,241	214,241
Incentive Compensation			-		(825,176)	(825,176)		(287,422)	(287,422)		(1,112,598)	(1,112,598)
Director's and Retirement Expenses			-		(278,267)	(278,267)		(31,375)	(31,375)		(309,641)	(309,641)
Grand Total	**$ 17,683,099**	**$ 16,670,826**	**$ (1,012,273)**	**$ 10,318,517**	**$ 8,953,541**	**$ (1,364,977)**	**$ 5,535,304**	**$ 7,694,358**	**$ 2,159,054**	**$ 33,536,921**	**$ 33,318,725**	**$ (218,196)**

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

TESTIMONY OF JOE T. CHRISTIAN

INDEX TO THE DIRECT TESTIMONY
OF JOE T. CHRISTIAN, WITNESS FOR
ATMOS ENERGY CORPORATION

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EXHIBITS

Exhibit JTC-1 – FY 2019 – Q3 FY 2024 Quarterly Capital Structure

Exhibit JTC-2 – Atmos Energy Authorized Capital Structures

Exhibit JTC-3 – Rate Recovery Mechanisms

Exhibit JTC-4 – Lead-Lag Study

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joe T. Christian. My business address is 5420 LBJ Freeway, 1600 Lincoln Centre, Dallas, TX 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Atmos Energy Corporation ("Atmos Energy" or "the Company") as Director of Rates & Regulatory Affairs (Shared Services).

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. I am responsible for leading and directing the rates and regulatory activity in Atmos Energy's eight-state service area. This responsibility includes developing the strategy, preparing the revenue deficiency filings and managing the overall ratemaking process for the Company. For the past twenty-three years, I have managed Company-specific dockets and other commission proceedings in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. I also managed Company-specific dockets in Georgia, Illinois, Iowa and Missouri relating to regulated assets that the Company has since sold.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from East Texas State University in 1985 with a Bachelor of Business Administration Degree, majoring in Accounting. In 1987, I received a Masters of

Business Administration from East Texas State University. I am a Certified Public Accountant in the State of Texas and a member of the American Institute of Certified Public Accountants. I have made presentations before the Texas Society of CPA's Energy Conference and other industry groups and the NARUC Staff Subcommittee on Accounting and Finance.

My professional experience includes approximately two years of public accounting experience with a large local accounting firm based in Dallas, Texas. In 1989, I accepted a position in the internal audit group with Atmos Energy. I was promoted to positions of increasing responsibility within the Atmos Energy finance team during my first nine years with the Company. I joined Atmos Energy's Colorado-Kansas operations as Vice President & Controller in June of 1998 and, effective December 1, 2001, was named Vice President of Rates & Regulatory Affairs. I assumed my current position on August 1, 2007.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am licensed by the State of Texas as a Certified Public Accountant ("CPA").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION") OR OTHER REGULATORY ENTITIES?

A. Yes. I have testified in the Company's previous three rate proceedings[1] as well as supported the Company's position in the Commission's Investigation of the Tax Cut and Job's Act on the Rates of Investor Owned Utilities.[2] I have submitted testimony before the Kansas Corporation Commission ("KCC") in five general rate case proceedings[3] and provided oral comments to the KCC in a rules investigation.[4] I have also submitted testimony before the Mississippi Public Service Commission to amend our tariffs to add a supplemental growth rider,[5] to amend our formula rate tariff to establish a system integrity plan and establish a rural development pilot program[6] and to request a system integrity rider and support our capital budget for 2015 through 2024.[7] I have also submitted testimony before the Louisiana Public Service Commission to amend our formula rate making tariffs to reduce lag related to system integrity investment as well as reaffirm our existing formula rate making

[1] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022); Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019); and Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications* (Ky. PSC May 3, 2018).

[2] *See* Case No. 2017-00481, *An Investigation of the Impact of the Tax Cuts and Job Act on the Rates of Atmos Energy Corporation, Delta Natural Gas Company, Inc, Columbia Gas of Kentucky, Inc., Kentucky-American Water Company, and Water Service Corporation of Kentucky* (Ky. PSC January 30, 2018).

[3] Docket Nos. 03-ATMG-1036-RTS, 08-ATMG-280-RTS, 10-ATMG-495-RTS, 12-ATMG-564-RTS, 14-ATMG-320-RTS.

[4] Docket No. 02-GIMX-211-GIV, General Investigation of the Cold Weather Rule.

[5] Docket No. 2013-UN-023.

[6] Docket No. 2014-UN-117.

[7] Docket No. 2015-UN-049.

tariffs.[8] Finally, I filed testimony before the Colorado Public Utilities Commission numerous times, including the Company's prior general rate case proceedings;[9] gas prudence reviews;[10] a Phase II class cost of service/rate design proceeding;[11] a transportation terms & conditions proceeding;[12] an upstream gas transportation matter;[13] a complaint proceeding regarding upstream gas transportation;[14] an Advanced Metering Infrastructure surcharge matter;[15] a proposal to extend the pilot related to recovering uncollectible gas costs through the Gas Cost Adjustment ("GCA") mechanism;[16] the Company's proposal to put into effect a System Safety and Integrity Plan;[17] and the Company's application for a Certificate of Public Convenience and Necessity to implement the Greeley Building Project.[18]

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am responsible for supporting the calculation of the Company's capital structure and embedded cost of debt to be used in establishing base rates for the future test period which is the 12 months ending March 31, 2026. I also provide an overview of the policy reasons for which Atmos Energy is requesting changes to its Pipeline

[8] Docket No. U-32987 (2014); Docket No. U-35535 (2020), Docket No. U-35937 (2022) and Docket No. U-36658 (2023).
[9] Proceeding Nos. 00S-668G, 09AL-507G, 13AL-0496G, 14AL-0300G, 15AL-0299G, 17AL-0429G, 22AL-348G.
[10] Proceeding Nos. 00P-296G and 03P-229G.
[11] Proceeding No. 02S-411G.
[12] Proceeding No. 02S-442G.
[13] Proceeding No. 04A-275G.
[14] Proceeding No. 08F-033G.
[15] Proceeding No. 10AL-822G.
[16] Proceeding No. 12AL-1003G.
[17] Proceeding No. 12AL-1139G.
[18] Proceeding No. 13A-0153G.

Replacement Program ("PRP") Rider recovery, a new Pipeline Modernization ("PM") Rider and removal of limitations on capital recovered through general rate cases. I am also responsible for supporting the calculation of the cash working capital requirements in the lead-lag study. I am sponsoring the following Filing Requirements (FR):

FR 16 (8)(b) 4	Allowance for Working Capital
FR 16(7)(h) (11)	Capital Structure Requirements;
FR 16(8)(j)	Cost of Capital summary

Q. WHAT ARE THE BASE PERIOD AND TEST PERIOD FOR THIS CASE?

A. The base period is January 1, 2024 through December 31, 2024 ("Base Period") and the forecasted test period is April 1, 2025 through March 31, 2026 ("Test Period").

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes, I am sponsoring Exhibits JTC-1 – JTC-4 which are attached to my testimony. Exhibit JTC-1 is the FY 2019 to Q3 FY 2024 quarterly capital structure of Atmos Energy. Exhibit JTC-2 is current Atmos Energy authorized capital structures. Exhibit JTC-3 is Summary of Capital Recovery Tariffs. Exhibit JTC-4 is the Lead-Lag Study utilized in the Company's revenue requirement.

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND EXHIBITS, AND THEIR ASSOCIATED SCHEDULES, AND MAKE THEM PART OF YOUR TESTIMONY?

A. Yes, I adopt the filing requirements, exhibits and their associated schedules and make them a part of my testimony.

Q. WHAT IS THE SOURCE OF THE DATA USED TO COMPLETE THE FILING REQUIREMENTS THAT YOU ARE SPONSORING?

A. The source of the data includes the accounting books and records of the Company which are being sponsored by Company witness Ms. Emily Wiebe.

The accounting books and records support the calculation of cash working capital requirements in the attached lead-lag study. The Company filed and supported a cash working capital requirements in Atmos Energy's three most recent case and has followed the same methodologies in each of these cases which more accurately reflects the working capital needs of the Company.[19]

Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications* (Ky. PSC May 3, 2018), Order at pp. 16-17 ("While the one eighth O&M methodology is a reasonable estimate of cash working capital absent a lead/lag study, Atmos's lead/lag study is part of the record of this proceeding and more accurately reflects the working capital needs of Atmos."); *see also* Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), final Order at 29 ("The Commission finds that the cash working capital allowance included in Atmos's rate base should be based upon the lead/lag study as filed, adjusted for expenses found reasonable herein."); *see also* Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022) final Order.

III. CAPITAL STRUCTURE AND COST OF DEBT

Q. HOW IS ATMOS ENERGY ORGANIZED?

A. Atmos Energy conducts its utility operations in eight states through unincorporated operating divisions.

Q. DO THE COMPANY'S UNINCORPORATED DIVISIONS ISSUE THEIR OWN DEBT OR EQUITY?

A. No. These divisions, including the Kentucky/Mid-States Division, are not separate legal entities. Instead, these unincorporated divisions collectively comprise the legal entity that is Atmos Energy Corporation. Therefore, all debt or equity funding of the operations performed by the utility divisions must be (and is) issued by Atmos Energy Corporation as a whole, on a consolidated basis.

Q. SHOULD ATMOS ENERGY'S CONSOLIDATED CAPITAL STRUCTURE BE USED AS THE BASIS FOR A CAPITAL STRUCTURE IN THIS PROCEEDING?

A. Yes. Although this proceeding only affects the rates which may be charged by the Company for its regulated utility operations in Kentucky, the appropriate capital structure for each of the Atmos Energy utility operating divisions, including its Kentucky/Mid-States Division, is equivalent to the consolidated capital structure for Atmos Energy as a whole. Atmos Energy's consolidated capital structure is appropriate for use in setting rates for the Company's Kentucky customers because

Atmos Energy provides the debt and equity capital that supports the assets serving those customers.

Q. HOW HAS THE COMPANY RELIED ON THE CONSOLIDATED CAPITAL STRUCTURE OF ATMOS ENERGY IN THIS PROCEEDING?

A. The capital structure that is appropriate for the Company's Kentucky operations in this proceeding is set forth in FR 16(8)(j). As shown on FR 16(8)(j), the capital structure is the Company's thirteen-month period end actual capital structure as June 30, 2024. The thirteen-month actual capital structure for the period ended June 30, 2024 is representative of the capital structure that will be in effect during the forecast period. As shown in that FR, column (G), short-term debt comprises 0.19%, long-term debt comprises 38.93% and equity is 60.88% of the Company's 13-month average rate base for the forward-looking test period.

Q. WHAT RATE DO YOU PROPOSE FOR THE EMBEDDED COST OF LONG-TERM DEBT CAPITAL IN SETTING RATES IN THIS CASE?

A. As shown in the calculation on Schedule J-3 F, column (e), a 4.11% weighted average cost of long-term debt is supported.

Q. IS THIS THE WEIGHTED AVERAGE COST OF LONG-TERM DEBT FOR THE THIRTEEN MONTHS ENDED JUNE 30, 2024?

A. No. The weighted average cost of long-term debt excludes securitized debt issued in connection with Winter Storm Uri costs associated with our Kansas operations.

This debt is held in a special purpose entity established for the sole purpose of securitizing Winter Storm Uri costs related to Kansas gas costs.

Q. HAS THE COMPANY HAS BEEN ACTIVE IN RAISING DEBT AND EQUITY FROM THE CAPITAL MARKETS THE PAST FIVE YEARS?

A. Yes, the Company has been active in raising both long-term debt as well as equity from the capital markets the past five years. Please see Exhibit JTC-1 FY 2019 - Q3 FY 2024 YTD Quarterly Capital Structure. As shown in this exhibit the Company, the Company's total capitalization has increased from $9.0 billion to $19.9 billion, which has required several capital raises from the market. However, the Company has issued long-term debt and equity in a manner that maintains the 38%-42% debt to 62%-58% equity range over this period. Being active in the debt and equity markets is important and necessary to support our ongoing investment in the safety and reliability of our gas distribution and transmission assets.

Q. DO YOU ANTICIPATE THAT THERE WILL BE ADDITIONAL DEBT AND EQUITY ISSUED DURING THE PENDENCY OF THIS CASE?

A. Yes, therefore I would be amenable to updating the capital structure and embedded cost of long-term debt during rebuttal to reflect any additional financings and changes to the equity balances of the Company. However, as demonstrated in Exhibit JTC-1, I do not expect this to have an appreciable impact on the relationship between debt and equity, only on the embedded cost of long-term debt.

Q. WHAT RATE DO YOU PROPOSE FOR THE COST OF SHORT-TERM DEBT CAPITAL IN SETTING RATES IN THIS CASE?

A. As shown in the calculation on Schedule J-2 F, column (e), a 17.14% weighted average cost of short-term debt is supported. Please note that the Company has had very little short-term debt outstanding during the 13 months ended June 30, 2024. Therefore, the commitment administrative fees associated with the short-term debt get spread over very few dollars which results in a higher average rate.

Q. IS THIS THE WEIGHTED AVERAGE COST OF SHORT-TERM DEBT FOR THE DAILY OUTSTANDING TWELVE-MONTH PERIOD END JUNE 30, 2024?

A. Yes.

Q. HAS THE THIRTEEN-MONTH ENDED JUNE 30, 2024 SHAREHOLDER EQUITY BALANCE BEEN ADJUSTED IN TO REFLECT THE ISSUANCE OF EQUITY DURING THE BASE OR FORECAST PERIOD?

A. No. I believe that the Company's incremental external financing along with cash flow reinvested in the business will result in an overall capital structure that is in line with the thirteen-month ended June 30, 2024 capital structure. Therefore, no adjustment is warranted at this time but, as noted above, it can be updated through the latest quarter end at the time of rebuttal.

Q. DID THE COMMISSION EXPRESS CONCERNS WITH THE COMPANY'S CAPITAL STRUCTURE IN CASE NOS. 2018-00281 AND 2021-00214?

A. Yes.

Q. HOW DID THE COMMISSION ADDRESS CAPITAL STRUCTURE IN THE COMPANY'S 2018-00281 CASE?

A. After discussing the Attorney General's positions, the Company's rebuttal and accepting the Company's updated position in rebuttal, the Commission stated, "Atmos's increase in common equity is concerning to the Commission, especially as compared to the proxy companies, which the Attorney General contends have a current equity ratio of 50.2 percent. Further, Atmos stated that the average debt/equity ratio for the proxy group, as noted by Value Line for 2021-2023, is 44 percent debt and 56 percent equity…."[20].

Q. HOW DID THE COMMISSION ADDRESS CAPITAL STRUCTURE IN THE COMPANY'S 2021-00214 CASE?

A. In the Company's 2021-00214 Case the Commission found Atmos Kentucky's common equity ratio should be reduced to 54.50% from the Company's filed position of 57.59.[21] The Commission stated that Atmos Kentucky's equity ratio

[20] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), final Order at 34.
[21] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022) final Order at 38.

remains significantly higher than its peers for no other reason than for stockholder benefits.[22] The Commission noted that the 54.50 equity ratio represented the median of proxy group equity ratios ranging from 37.5% to 60% for the 2024-2026 prospective period.[23] The Commission also noted that it will review the proxy group common equity ratios in subsequent rate filings.[24]

Q. HOW DO YOU RESPOND TO THESE ALLEGATIONS AND CONCERNS?

A. As noted in my rebuttal in Case No. 2018-00281 and again in my direct testimony in Case No. 2021-00214, the capital structure proposed and supported in this case represents an actual cost, not a hypothetical or subsidiary cost that is part of a larger holding company and can be leveraged at a higher level in the corporate structure. Unlike the other large Kentucky utility companies, Atmos Energy does not have a holding company structure. I also noted that, as the factors used by the credit rating agencies to evaluate utilities demonstrate, relying too heavily on long-term debt financing creates risk, as does a regulatory environment that is not supportive of utilities' ability to recover their actual costs and to have the opportunity to earn a fair return on their investments. Moreover, the Company's capital structure is reflective of what is necessary to maintain its current credit metrics. The

[22] *Id*.
[23] *Id*.
[24] *Id*.

Company's current credit metrics enable it to access long-term debt and the capital markets at more favorable terms, which is a benefit to customers.

Q. DO YOU AGREE WITH THE COMMISSION'S ALLEGATION THAT THE COMPANY'S EQUITY RATIO REMAINS SIGNIFICANTLY HIGHER THAN ITS PEERS FOR NO OTHER REASON THAN FOR STOCKHOLDER BENEFIT?

A. Absolutely not. The language in the Commission's order drew a conclusion that, very simply, was not supported by the evidence. The only analytical support provided in evidence was that provided by the Company, which demonstrates the rationale for maintaining our strong balance sheet. Every utility's capital needs are unique and Atmos Energy's corporate structure is fundamentally different than its peer comparisons. The ability to invest in the safety and reliability of utility systems requires maintaining a strong balance sheet and the Company's capital structure is reflective of this commitment to invest in safety and reliability in Kentucky.

Q. WHY IS IT IMPORTANT FOR THE COMPANY TO CALCULATE ITS REVENUE REQUIREMENT BASED UPON ITS ACTUAL CAPITAL STRUCTURE?

A. Safe and reliable service cannot be maintained at a reasonable cost if the Company does not have the financial flexibility and strength to access the competitive capital

markets on reasonable terms. As recently highlighted in a Special RTI Event, Utility Credit Ratings 101 Webinar[25], the factors used by the credit rating agencies to evaluate utilities demonstrate, relying too heavily on long-term debt financing creates risk, as does a regulatory environment that is not supportive of utilities' ability to recover their actual costs and to have the opportunity to earn a fair return on their investments. Increasing the percentage of long-term debt in the Company's capital structure negatively affects the key financial indicators relied upon by the credit rating agencies, which puts the Company at risk of a credit rating downgrade and increases in the cost of debt financing, both of which adversely affect all of Atmos Energy's stakeholder groups, including its customers, its shareholders and its bondholders.

Q. CAN ATMOS ENERGY MAINTAIN SAFE AND RELIABLE SERVICE AT A REASONABLE COST OVER THE LONG-TERM IF IT DOES NOT RECOVER ITS ACTUAL COSTS?

A. In order to provide safe, reliable and affordable service to its customers, Atmos Energy must meet the needs and serve the interests of its various stakeholders, including customers, shareholders and bondholders. The interests of these stakeholder groups are aligned with maintaining a healthy balance sheet, strong

[25] https://maxxwww.naruc.org/forms/store/ProductFormPublic/RTI-Utility-Credit-Rating-101-2024-On-Demand?ticket=ST-1726951786-XNSAnKY4X0MNd5sZxqSwbTQrMS8gGpAo

credit ratings and a supportive regulatory environment, so that the Company has access to capital on reasonable terms in order to make necessary investments.

Moreover, stakeholder interests cannot be aligned if utilities do not have the financial flexibility and strength to access the competitive capital markets on reasonable terms. The authorization of a capital structure other than the Company's actual capital structure will weaken the Company's financial condition and adversely impact the Company's ability to address expenses and investment, to the detriment of customers and shareholders. Safe and reliable service for customers cannot be sustained over the long term if the interests of shareholders and bondholders are minimized such that the public interest is not optimized.

Q. HAS THE COMPANY'S REGULATORS IN JURISDICTIONS OUTSIDE KENTUCKY RECOGNIZED ITS ACTUAL CAPITAL STRUCTURE?

A. Yes. Exhibit JTC-2 shows the most recently approved capital structures in each of Atmos Energy's jurisdictions. The equity cap imposed by Kentucky is, by far, an outlier compared to other regulatory jurisdictions and is also an outlier among other Kentucky regulated LDCs.

Q. HAS THE COMPANY'S STRONGER EQUITY POSITION ALLOWED IT TO SUCCESSFULLY MANAGE VARIOUS CHALLENGES THE PAST FIVE YEARS?

A. Yes. Although the Tax Cut and Jobs Act ("TCJA") reduced the federal income tax rate and created a need to return deferred taxes to customers resulting in a negative impact to cash flow, the Company has been able to adjust its external financing needs and not experience a downgrade by ratings agencies. When the COVID-19 Pandemic resulted in Emergency Orders being issued across all of the Company's service territories to not disconnect the Company was able to raise additional debt early in the pandemic to maintain its liquidity during uncertain times. While the Commission lowered the Company's depreciation rates and therefore cut its cash flow from operations, it has been able to manage through the additional strain on our financial metrics. Lastly, one of the most important examples regarding the financial strength the Company's balance sheet brings at its current capitalization, as part of responding to Winter Storm Uri and despite being put on credit watch by both ratings agencies the Company was able to quickly raise $2.2 billion to fund extraordinary gas cost on very short notice and increase our liquidity through a new short-term credit facility. Without the Company's strong financial balance sheet in place these examples could have had serious long-term detrimental effects to the Company's customers. The Commission's current equity cap on the Company's

capital structure is not consistent with the financial strength required by the Company to continue the provision of safe and reliable service to its customers in Kentucky.

Q. HOW HAS MOODY'S CREDIT OPINION CHANGED SINCE THE PREVIOUS CASE?

A. On April 10, 2024, Moody's changed the Company's Outlook to "negative", stating that "We had previously expected that the company's financial profile would recover after it exhibited lower than historical metrics in 2022 and 2023. However, due to a sizable capex program and the inherent regulatory lag in some of its jurisdictions, we project that Atmos' cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio will more likely be between 20%-22% over the next several years; still strong but below historical levels in the 25% range." As noted in Moody's statement, the Company does not have strong going forward metrics. This tells me that maintaining our capital structure at the levels shown in Exhibit JTC-2 continues to be appropriate and that we are not equity rich as the AG's intervenors suggested in our previous case.

Q. WOULD SETTING THE COMPANY'S CAPITAL STRUCTURE AT ANYTHING OTHER THAN ACTUAL BE BENEFICIAL TO THE CUSTOMER?

A. No. Contrary to the Commission's finding in Case No. 2021-00214, a regulatory environment that does not permit a utility to have a reasonable opportunity to earn a fair return on its prudently incurred cost leads to poor results in the long run. Supporting utilities that invest in the energy infrastructure in a prudent and efficient manner should be encouraged.

Q. DOES ATMOS ENERGY'S ORGANIZATIONAL STRUCTURE SUPPORT CALCULATING THE RATES IN KENTUCKY ON THE COMPANY'S ACTUAL CAPITAL STRUCTURE?

A. Yes. Atmos Energy conducts utility operations in eight states through unincorporated divisions, including the Company's Kentucky operations.

Q. WHY IS THIS ORGANIZATIONAL STRUCTURE OF ATMOS ENERGY (NON-HOLDING COMPANY) AN IMPORTANT DISTINCTION COMPARED TO ATMOS ENERGY'S PROXY GROUP?

A. Unlike other utilities that operate in Kentucky, the actual capital costs upon which Atmos Energy's Kentucky rates are calculated are not complicated by differing levels of debt/equity ratios at the holding company level vs. the subsidiary level.

Q. ARE THERE ADVANTAGES TO ATMOS ENERGY'S FINANCIAL STRUCTURE?

A. Yes. Operating all of the distribution and transmission business within Atmos Energy Corporation saves administrative costs, results in a more transparent business model, provides more transparency in financial reporting, and allows us to focus on the operational needs of the gas distribution and transmission business and how best to meet the financing needs as we progress through our investment in natural gas infrastructure for system replacement and growth.

IV. SAFETY-RELATED CAPITAL INVESTMENT AND RATE RECOVERY

Q. BRIEFLY DESCRIBE THE BACKGROUND OF SAFETY-RELATED INVESTMENTS THROUGHOUT ATMOS ENERGY.

A. In 2011, as a result of catastrophic incidents on natural gas systems, a Call to Action was issued by United States Secretary of Transportation Ray LaHood, seeking to engage state regulators, technical experts and pipeline operators in identifying pipeline risks and repairing, rehabilitating and replacing the highest risk infrastructure. Further, the National Association of Regulatory Utility Commissioners ("NARUC") issued a resolution in 2013 encouraging state commissions to "consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems."

Since that time, the Company has worked effectively with its regulators to make great strides in its pace of modernizing infrastructure. Because this effort

requires significant levels of incremental capital investment beyond what normal system growth and maintenance would require, creative solutions to address capital investment lag must be utilized in addressing the replacement of aging infrastructure in a financially sustainable manner. NARUC recognized this connection in its encouragement of appropriate rate recovery mechanisms to facilitate modernization and replacement of the nation's aging natural gas pipeline systems. Nearly every state has since adopted one or more forms of such mechanisms.

Q. HAS THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") ADDRESSED THIS ISSUE?

A. Yes. On April 16, 2015, FERC issued a Policy Statement addressing cost recovery mechanisms for modernization of interstate natural gas facilities in FERC Docket No. PL15-1-000. The Policy Statement states that FERC has established a policy allowing interstate natural gas pipelines to seek recovery of certain capital expenditures made to replace infrastructure through a surcharge mechanism. On page 1 of its Policy Statement, FERC stated that its intent is to "provide greater certainty regarding the ability of interstate natural gas pipelines to recover the costs of modernizing their facilities and infrastructure to enhance the efficient and safe operations of their systems."

The FERC's Policy Statement outlined the standards that FERC requires interstate pipelines (whose rates are regulated by FERC rather than state commissions) to establish alternate ratemaking mechanisms such as surcharges or

trackers to allow them to recover the costs of replacing obsolete infrastructure and thereby enhance the efficient and safe operations of their pipeline systems.

Q. DID FERC'S POLICY STATEMENT ADDRESS THE ISSUE OF SAFETY AS A DRIVER FOR THE NEED TO REPLACE AGING INFRASTRUCTURE?

A. Yes. In Paragraph 26 of the Policy Statement, FERC stated:

> *With regard to safety and reliability . . . recent pipeline accidents, including the September 2010 pipeline rupture in San Bruno, California, demonstrate the potential consequence of aging pipeline facilities that are not properly repaired, rehabilitated or replaced. OPS states that 59% of existing natural gas pipelines were built before 1970 and 69% of existing natural gas pipelines were built before 1980. DOE notes that more than half of the country's natural gas and gathering infrastructure is over 40 years old. As OPS points out, while aging pipelines are not inherently risky, older facilities have been exposed to more threats and were likely constructed without the benefit of today's safety standards or quality materials.*

Q. WHAT HAS BEEN THE IMPACT OF THE INCREASED CAPITAL INVESTMENT ON RATEMAKING?

A. The Company's emphasis on safety and increased levels of capital investment for infrastructure replacement extends to all of the eight states in which Atmos Energy operates. As a consequence of increased capital investment in infrastructure replacement, each of these jurisdictions has experienced an increase in the frequency of rate adjustments. In order to overcome the need for frequent, litigious and expensive general rate cases, many regulatory jurisdictions have implemented one or more of an array of new capital trackers, annual rate review tariffs and other innovative ratemaking processes to facilitate these new incremental levels of capital investment in system integrity.

Q. PLEASE PROVIDE AN OVERVIEW OF THE MECHANISMS CURRENTLY IN EFFECT IN ATMOS ENERGY JURISDICTIONS WHICH LESSEN THE FREQUENCY OF COMPREHENSIVE RATE CASES.

A. Exhibit JTC-3 summarizes the key rate capital recovery tariffs currently employed in each Atmos Energy jurisdiction. Column (a) shows the numerous areas currently operating under a comprehensive annual rate review process. Column (b) shows the capital investment lag experienced with each of these annual mechanisms.

Capital recovery tariffs specifically supporting infrastructure replacement are found in columns (e) through (h) on Exhibit JTC-3. Those in columns (e) and (f) represent six jurisdictions in four states where special capital treatment is afforded to infrastructure replacement programs within the construct of a comprehensive annual ratemaking mechanism. Each of these jurisdictions cut the impact of capital investment lag to zero for qualified infrastructure replacement investments.

Columns (g) and (h) show eight jurisdictions in five states that have special capital treatment for infrastructure replacement programs on a stand-alone basis, without comprehensive annual rate reviews. Each of these jurisdictions has reduced the impact of capital investment lag for qualified investment in replacements by allowing rates to change outside a fully litigated rate case proceeding.

Q. FOR PURPOSES OF EXHIBIT JTC-3, PLEASE DEFINE WHAT IS MEANT BY "CAPITAL INVESTMENT LAG".

A. Capital investment lag represents the average number of months between the time that a capital investment is closed, placed into service and used by our customers and the time that this investment is reflected in customer rates. As indicated in Column (b), most of Atmos Energy's comprehensive annual review mechanisms have a capital investment lag of 12 to 15 months. For a jurisdiction employing a typical historic 12-month test period ending capital basis for ratemaking, the average lag is six months plus the number of months between the end of the historic test period and when new rates are implemented. However, some jurisdictions have implemented measures to eliminate capital investment lag. For example, Mississippi allows a "forward-looking" test year in its annual review mechanism, which prevents capital investment lag.

Q. WHAT ARE THE FINANCIAL CONSEQUENCES OF CAPITAL INVESTMENT LAG?

A. The immediate consequence is that the Company's capital investment goes unrecovered and the Company bears the costs of this investment along with depreciation expense, property taxes and carrying costs during the lag period. In fact, the term "lag" is misleading with respect to recovery of these costs because these costs incurred before being reflected in rates are <u>never</u> recovered by the Company. In this way, the capital investment lag creates a greater gap between the "allowed" and the "achieved" return. Because capital spending is the primary cause of the Company's need for rate adjustments, the impact of capital investment lag is a serious impediment to the ability of the Company to have a reasonable

opportunity to earn its allowed rate of return and it also increases pressure to file more frequent general rate proceedings.

Q. WHERE DOES KENTUCKY STAND WITH RESPECT TO ALLOWING RECOVERY OF AND REDUCING LAG ON INTEGRITY RELATED CAPITAL INVESTMENTS COMPARED TO THE OTHER JURISDICTIONS IN WHICH ATMOS ENERGY OPERATES?

A. Kentucky currently uses a PRP Rider mechanism for qualified investments on system replacement with no lag under that mechanism. This statutory mechanism is helpful in facilitating our efforts to replace Atmos Energy's system in Kentucky from a regulatory lag perspective but is insufficient from a gross capital investment perspective to fully support the necessary levels of capital expenditures Atmos Energy needs to make to support system safety and reliability, as discussed by Company witness Ryan Austin.

Q. PLEASE DESCRIBE HOW THE GROSS CAPITAL INVESTMENT LIMITATIONS IN KENTUCKY COMPARE WITH THE OTHER JURISDICTIONS IN WHICH ATMOS ENERGY OPERATES.

A. As shown in column (k) in Exhibit JTC-3, there are two other states – Colorado and Kansas – that have a cap of some type on the amount of capital that can be recovered through established infrastructure replacement trackers to reduce lag. For this reason, the Company also files more frequent general rate cases in these jurisdictions to mitigate the effect of these limitations on the Company's opportunity to earn a reasonable return so that it can continue to fund needed capital investment in these systems. The main difference between these states and

Kentucky is that regulatory bodies in Colorado and Kansas have never tried to limit the amount of capital that can be recovered through a general rate case, other than by applying a prudence standard common to all our jurisdictions (reflected in column (l) of Exhibit JTC-3). In fact, Atmos Energy has never received or seen an order of another utility similar to that in Case No. 2018-00281 in which a regulatory authority limited the amount and type of capital spending a utility can recover through a general rate case.

The rest of our jurisdictions (other than Colorado, Kansas and Kentucky) allow the Company to present and justify its capital needs to support system integrity wholistically and comprehensively through the designated mechanism or special accounting treatment. This approach is in the public interest because it provides the state regulators with a comprehensive look at the planned spending and allows Atmos Energy a thorough opportunity to explain and support the expected level of needed investment for review by the regulatory authorities in those states. It also obviates the need for more frequent general rate case filings in which every aspect of the Company's rate structure is litigated, rather than simply reviewing the prudence of the proposed capital needs and applying Commission-established rate calculations to the approved level of investment.

Q. DOES THE KENTUCKY PRP PROVIDE A SUFFICIENT BRIDGE AND EXTENSION BETWEEN RATE CASES?

A. No, because the PRP does not cover the entire level of capital investment the Company intends to make in system integrity. This problem is exacerbated by the

additional limitations on the Company's ability to recover capital investment through general rate cases.

Q. PLEASE FURTHER DESCRIBE THE PRP.

A. As stated in the Rider, "The PRP Rider may be filed annually on or around August 1st of each year. The filing will reflect the anticipated impact on the Company's revenue requirements of net plant additions related to bare-steel pipe and Aldyl-A pipe replacement on a "case by case" basis, as offset by operations and maintenance expense reductions during the upcoming fiscal year ending each September as well as a balancing adjustment to reconcile collections with actual investment for the program year from two years prior. Such adjustment to the Rider will become effective with meter readings on and after the first billing cycle of October."

Q. HAS ATMOS ENERGY MADE SAFETY-RELATED INVESTMENTS ABOVE AND BEYOND THE INVESTMENT RECOVERABLE THROUGH PRP?

A. Yes. The table below shows the level of safety and reliability related investment Atmos Energy has made in recent years. As the table indicates, Atmos Energy's safety and reliability related investment not recovered through PRP has been significant.

Table JTC-1 - Safety and Reliability Spending

Description	2020	2021	2022	2023	YTD-2024
Public Improvements	$ 876,210	$ 222,158	$ 360,143	$ 223,769	$ 1,800,834
System Improvements	$ 2,832,706	$ 1,350,998	$ 1,265,685	$ 3,028,338	$ 912,820
System Integrity	$ 19,298,711	$ 21,321,837	$ 23,274,721	$ 18,589,468	$ 25,350,822
Non-PRP Investment	**$ 23,007,627**	**$ 22,894,993**	**$ 24,900,550**	**$ 21,841,574**	**$ 28,064,476**
PRP Investment	**$ 28,234,091**	**$ 28,947,381**	**$ 33,212,992**	**$ 31,892,547**	**$ 28,423,684**
Grand Total	**$ 51,241,718**	**$ 51,842,374**	**$ 58,113,542**	**$ 53,734,121**	**$ 56,488,160**

Even with the increase in the PRP cap to $30 million, Atmos Energy is still spending well above and beyond the level of investment is currently only recovered outside the PRP Rider.

Q. HAS THE COMMISSION RECOGNIZED THE NEED FOR ACCELERATED PIPELINE REPLACEMENT IN KENTUCKY?

A. Yes. In Case No. 2018-00281 the Commission stated the following:

> *The Commission has consistently found that the public interest is served by replacing potentially unsafe, aged gas pipelines through the adoption of pipeline replacement programs that have been approved as being fair, just and reasonable. To the extent that the pipeline eligible for replacement poses a safety risk to the utility's customers, service areas, and employees, the Commission reiterates that it is in favor accelerated replacement. The Commission believes that pipeline replacement programs improve public safety and reliability of service for customers…*
>
> *Through the PRP process, the Commission is able to separately review and scrutinize each project and expenditure annually, with the opportunity for the Attorney General and potentially others, to intervene in the PRP proceedings. The Commission finds that the already established separately review for the accelerated replacement of bare steel pipelines in Atmos' system to be a more streamlined and efficient process than Atmos's proposal to include the PRP projects in an annual base rate case. During a base rate case, a multitude of issues are examined in detail by the parties and the Commission. If PRP projects are also included in the base rate case then the Commission and the intervenors may not have adequate time to review and analyze the proposed projects.*[26]

[26] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), Order at 14-15.

Q. HAS THE LEGISLATURE OF KENTUCKY RECOGNIZED THE NEED FOR ACCELERATED PIPELINE REPLACEMENT IN KENTUCKY?

A. Yes. In 2005, The Kentucky legislature provided specific statutory authorization for the Commission to approve pipeline replacement programs for natural gas utilities, codified as K.R.S. § 278.509.

Q. HOW IS THE COMPANY PROPOSING TO CHANGE THE WAY CAPITAL INVESTMENT IS RECOVERED IN THIS RATE CASE?

A. The Company is proposing to take a three-pronged approach in this case. First, Atmos Energy is requesting removal of the cap of $30 million on the annual investment presented for recovery through the PRP Rider. This will allow the Commission to review annually the comprehensive proposed budget to replace infrastructure on the distribution consistent with Atmos Energy's Distribution Integrity Management Plan ("DIMP").

Second, Atmos Energy is requesting a similar mechanism called the PM Rider, which will allow the Commission to review annually the proposed budget specifically for compliance with the PHMSA rules described in Mr. Austin's testimony applicable to the Company's transmission assets. The PM Rider would work similarly to the PRP Rider, in that the Company would file annually the anticipated impact on the Company's revenue requirements of net plant additions related to compliance with 49 C.F.R. §192.624, 192.710, and 192.607 as those pipeline safety regulation apply to Atmos Energy's transmission pipeline in Kentucky. The proposed projects would be reviewed and approved for rates effective two months following the filing. At this time, Atmos Energy has limited

the request to net plant additions resulting only from these specific regulations stemming from the PHMSA "Mega Rule." Should other specific directives of PHMSA arise that would lend themselves to inclusion in the PM Rider sometime in the future, the Company would make a request to expand the application of the PM Rider at that time for consideration by the Commission.

Third, Atmos Energy is requesting that the Commission clarify that any past directives of the Commission for Atmos Energy to limit the capital expenditures recovered through a general rate case ("non-PRP" capital) are no longer applicable, and the Company is allowed to present net plant additions in a general rate case for which the Company can meet its burden of proof "to show that the increased rate or charge is just and reasonable."[27]

Q. IS THIS TYPE OF RATE TREATMENT SIMILAR TO FRAMEWORKS UNDER WHICH ATMOS ENERGY OPERATES IN OTHER STATES AND DIVISIONS WITHIN THOSE STATES?

A. Yes. While each state and division within a state has its own nuanced approach, they all achieve the goal of providing Atmos Energy with a regulatory framework that supports the capital investments needed in the system balanced with maintaining just and reasonable rates. The above-described framework in Kentucky would accomplish this goal.

[27] K.R.S. §278.190.

Q. IF THE RELIEF REQUESTED IN THIS CASE IS GRANTED, DOES ATMOS ENERGY ANTICIPATE THAT ITS RATES IN KENTUCKY WILL BECOME UNAFFORDABLE?

A. No. Atmos Energy has undertaken a prudent approach to its infrastructure replacement programs in each of its service territories and has rates in line with its peer utilities in each region. In every state that we serve, we are bound by thorough review of our regulatory bodies to ensure that our costs are prudent and our rates are just and reasonable. Our approach to infrastructure replacement program in our service territories has gone on for well over a decade and natural gas is still the most economical way to provide energy to the home.

Q. IS ATMOS ENERGY'S CAPITAL INVESTMENT, INCLUDING ITS SAFETY-RELATED INVESTMENT, CONSISTENTLY OUTPACING DEPRECIATION EXPENSE?

A. Yes. Our overall capital budget for FY 2025 is $34.2 million as compared to the depreciation request indicates that we are investing at a level approximately 1.7x that of the depreciation expense reflected in its current rates.

V. CASH WORKING CAPITAL

Q. WHY HAS THE COMPANY INCLUDED A LEAD-LAG ANALYSIS WITH THIS CASE?

A. Although the Company was reluctant to file a lead-lag study in prior cases[28] the Company filed a study in its previous three cases (Case Nos. 2017-00349, 2018-

[28] The Company had utilized the formula approach of 1/8 of operations and maintenance expenses since its purchase of Western Kentucky Gas Company in 1987.

00281 and 2021-00214), the first two of which were accepted "as filed" in the calculation of the rate base in the final order. However, in case No. 2021-00214 the Commission made several material changes to the Company's lead-lag study that resulted in a poor outcome for the Company and which do not accurately reflect the sources and uses of working capital of a utility in its daily operations. In light of the Commission's more reasonably balanced orders in Case Nos. 2017-00349 and 2018-00281 the inclusion of a lead-lag study following the same methodology accepted in calculating lead-lag in Case No. 2017-00349 and Case No. 2018-00218 is appropriate in this case.

Q. WHAT IS THE PURPOSE OF THE LEAD-LAG ANALYSIS?

A. Rate base is the value of invested capital, including all items used to provide utility service. Cash working capital is the capital investment in addition to other rate base items that is required to bridge the gap between when cash is paid for expenses necessary to provide service and when cash is received from customers for that service. As stated above, this amount is included in rate base. A lead-lag analysis is a method of measuring the amount of cash working capital used to provide utility service. This analysis compares two different lags. The lag between (1) the provision of service to customers and the collection of cash from customers is compared to the lag between (2) the recording of expenses and the payment of cash by the Company for those expenses.

Q. DO YOU HAVE ANY PAST EXPERIENCE PERFORMING LEAD-LAG STUDIES?

A. Yes. In addition to our most recent Kentucky rate cases I have prepared several lead lag studies for the Company, including studies filed in Atmos Energy's previous rate cases in Tennessee, Colorado and Virginia.

Q. WHERE HAVE YOU INCLUDED THE LEAD-LAG STUDY?

A. I have included the lead lag study as Exhibit JTC-4. For reference, I have continued to name the various Schedules within Exhibit JTC-4 "ATO-CWCx"

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC1.

A. This schedule actually consists of two parts - Schedule ATO-CWC1A and ATO-CWC1B. Schedule ATO-CWC1A summarizes the results of the lead-lag analysis for the forecasted test year ended March 31, 2026. It shows the calculation of the cash working capital requirement based on revenue and expense lag days and projected expense amounts in the proposed revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC1B

A. Schedule ATO-CWC1B summarizes the results of the lead-lag analysis for the base period ended December 31, 2024. It shows the calculation of the cash working capital requirement based on revenue and expense lag days and actual expenses for the base period.

Q. PLEASE DESCRIBE HOW SCHEDULES ATO-CWC 1A AND 1B ARE ARRANGED?

A. Column (a) lists the type of expenses analyzed in the lead-lag study including gas costs, O&M labor, other O&M non-labor, taxes other than income, federal income tax, state income tax, depreciation, long term and short-term debt interest expense and return on equity. Schedule ATO-CWC1A Column (b) contains the projected expenses for the forecasted test period and Schedule ATO-CWC1B Column (b) contains the expenses for the base period test year. Schedule ATO-CWC1A (c) divides the expenses in Column (b) by 365 and ATO-CWC1B Column (c) divides the expenses in Column (b) by 366 to arrive at the average daily expense. Column (d) contains the revenue lag which is calculated on Schedule ATO-CWC2. Column (e) contains the expense lags which are calculated on Schedule ATO-CWC3 through Schedule ATO-CWC9 and their related Workpapers. Column (f) calculates the net lag by subtracting the expense lag from the revenue lag. Column (g) contains the calculation of the cash working capital requirement which is calculated by multiplying Column (c) times Column (f). The cash working capital requirement to be *deducted* from rate base for the forecasted test period is $2.2 million.

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC2.

A. The average revenue lag is calculated on Schedule ATO-CWC2. The revenue lag is the average number of days from the time service is provided by the company until revenue related to that service is available to pay bills. It consists of four subparts: the service lag, the billing lag, the collection lag and the bank lag.

Q. WHAT IS THE SERVICE LAG?

A. The service lag is the average number of days from the time service is provided until the meter is read. Since service is provided daily and meters are read monthly, the service lag is one-half of a month or 15.25 days in a leap year such as 2024.

Q. WHAT IS THE BILLING LAG?

A. The billing lag is the time lag from meter reading to bill issuance. The average billing lag based on all bills issued in a heating season month (November) and a non-heating season month (August), was 0.3113 days, as compared to 0.64 days in the previous case.

Q. WHY HAS THE BILLING LAG SHOWN IMPROVEMENT SINCE THE PREVIOUS CASE?

A. I attribute the improvement to the deployment of automated meter reading as well as fewer exceptions to be individually investigated prior to a bill issuance. Our SAP billing system, in combination with automated meter reading has enabled more bills to be generated on the same day of the read as compared to recent cases.

Q. WHAT IS THE COLLECTION LAG?

A. The collection lag is the average number of days between issuing a bill and receiving payment. This was calculated by dividing the average daily accounts receivable balance by the average daily revenue plus billed taxes. The total revenue plus billed taxes may be found on WP 2-2. It resulted in a lag period of 18.07 days and is substantially the same since the previous case result of 17.31.

Q. WHAT IS THE BANK LAG?

A. The bank lag is the one-day lag between receiving payment through one of the Company's fourteen pay channels and having funds available to draw at the bank. Customer accounts receivable balances are credited when payment is received.

Q. WHAT IS THE TOTAL AVERAGE REVENUE LAG?

A. The resulting total average revenue lag is 34.63 days, as shown on the last line of Schedule ATO-CWC2. This substantially unchanged from 34.16 in the previous case.

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC3.

A. Schedule ATO-CWC3 shows the calculation of the average purchased gas cost payment lag of 39.49 days from the delivery of the gas to the payment for the gas. The schedule shows the service dates, the invoice date and the payment date for all gas invoices in the base period.

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC4.

A. Schedule ATO-CWC4 shows the calculation of the average payroll lag, which is the average number of days from the time service is provided until payroll related to that service is paid. The payroll lag days consists of: the service lag, the payment lag and the check-clearing lag. The service lag is the average number of days from the time labor is provided until the end of the pay period. The Company uses a two-week pay period, so the service lag is seven days. The payment lag is the average number of days between the end of the pay period and payment date. With the Company's practice of paying on Friday for a pay period that ended the previous Friday, the payment lag is seven days. Most employees receive their pay via direct deposit and therefore have no check-clearing lag. However, the few employees that are paid by check result in an average check-clearing lag of 0.33 days. The total average payroll lag is 14.33 days.

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC5.

A. Schedule ATO-CWC5 shows the calculation of the average number of lag days for other O&M expenses. The calculation is based on an analysis of payments for the twelve months ended June 30, 2024. I analyzed a random sample of 413 invoices out of the 8,263 total Kentucky O&M invoices to determine the lag between the date services were provided to the Company and the date the Company paid the bill for those services. In most cases, the service period could be determined from the

invoice. If no information was available regarding the date service was provided, then the date of the invoice was used in most cases other than utilities, telecom and rent. Please see WP 5-1 for the analysis.

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC6.

A. Schedule ATO-CWC6 shows the calculation of the average payment lag days for taxes other than income tax. As each tax has its unique payment due date, the calculation of the lag is shown separately for each type of tax (payroll taxes - FICA and unemployment, ad valorem taxes, taxes property and other, DOT fees, Public Service Commission taxes and franchise and other pass through taxes).

Q. PLEASE DISCUSS THE LAG RELATING TO PAYROLL TAXES.

A. Payroll taxes consist of FICA taxes and unemployment taxes. FICA taxes are paid by wire on the first banking day before each payday. Since paydays are normally on Fridays, FICA lag days are equal to the payroll lag days for direct deposit employees of 14 days less 1 day, for a total lag of 13 days. Unemployment taxes are paid quarterly at the end of the month following each quarter. Therefore, for unemployment taxes, the lag, as calculated from the mid-point of the quarter to the payment date at the end of the following month plus the payroll service lag, is 83.6 days.

Q. PLEASE DISCUSS THE LAG RELATING TO AD VALOREM TAXES.

A. Kentucky ad valorem taxes for a calendar year are paid as billed throughout the year following the year of assessment. Therefore, the Kentucky ad valorem tax lag, as calculated from the mid-point of the calendar year to the payment date, is 278.99 days. Ad valorem taxes allocated from Shared Services are paid by January 31 for the year following the assessment. Therefore, the SSU ad valorem tax lag as calculated from the mid-point of the calendar year to the payment date is 213.50 days.

Q. PLEASE DISCUSS THE LAG RELATING TO TAXES PROPERTY AND OTHER.

A. Taxes Property and Other consist of various franchise agreements that are paid on a per meter basis rather than on a revenue basis and Kentucky Highway Use Tax. The expense lag on the franchise taxes are determined by the franchise with each individual city and may be a prepayment or paid in arrears. The Kentucky Highway Use Tax is paid at the end of the month in the month following the end of each quarter. The weighted average lag of all taxes paid is a prepayment of 58.82 days.

Q. PLEASE DISCUSS THE LAG RELATING TO THE FRANCHISE AND OTHER PASS THROUGH TAXES.

A. Franchise and other pass through taxes consist of franchise taxes that are paid on a revenue basis, Kentucky sales use tax and Kentucky school tax. The franchise taxes

are paid at the end of the month following the end of the quarter. The Kentucky sales use tax and school tax are paid at the end of the month for the prior month. The weighted lag for Franchise and other pass through taxes is 40.37 days.

Q. PLEASE DISCUSS THE LEAD RELATING TO THE PUBLIC SERVICE COMMISSION ASSESSMENT.

A. The Public Service Commission Assessment is prepaid annually on June 26 for the subsequent July 1 to June 30 assessment period. The lead for the PSC assessment is 186.50 days.

Q. PLEASE DISCUSS THE LAG RELATING TO THE DOT FEE.

A. The annual DOT fee lag of 59 days is calculated from the midpoint of the fiscal year to the payment date on May 28th of the following calendar year.

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC7.

A. Schedule ATO-CWC7 shows the calculation of the federal income tax lag. Income taxes for the base period are paid in four quarterly payments during the year. The average lag from the midpoint of the base period to the payment dates is 38.25 days. This is the lag for paying current taxes, however taxes that are deferred are recorded as a rate base credit and thus have an expense lag of zero days.

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC8.

A. Schedule ATO-CWC8 shows the calculation of the state income tax lag. State income taxes for a fiscal year are paid on the same schedule as federal income taxes.

Therefore, the average lag from the midpoint of the tax year to the payment dates is also 38.25 days for paying current taxes and zero days for deferred taxes.

Q. PLEASE DESCRIBE SCHEDULE ATO-CWC9.

A. Schedule ATO-CWC9 shows the calculation of the long-term debt lag. Long-term debt interest expense includes monthly payments and semi-annual payments. Interest is recorded on an accrual basis and paid in the period it is due. The long-term debt lag, as calculated from the mid-point of the accrual period to the payment date, averages 91.40 days.

Q. PLEASE DESCRIBE SHORT-TERM DEBT LAG ON ATO-CWC1.

A. In the base period short-term debt interest expense was for commercial paper. Most commercial paper issued by the company is very short-term. Commitment fees are generally paid at the end of the quarter. Other base period short-term debt costs were prepaid. The weighted average short-term debt cost payment lag used in this study is 19.40 days.

Q. HOW DID YOU TREAT PREPAID ITEMS IN THE CALCULATION OF CASH WORKING CAPITAL?

A. Expenses that are paid by the Company before they are recorded as an expense are included with a negative lag to reflect the difference between the payment of the expense and the recording of the expense. With this method both the lag from the

payment to the recording of the expense and the subsequent revenue lag from the provision of service to the receipt of cash are recognized in rate base.

Q. IS DEPRECIATION EXPENSE PROPERLY INCLUDED IN THE LEAD-LAG STUDY.

A. Yes, because the payment for the asset precedes the receipt of service from the asset and the recording of depreciation expense. The lag between payment for the asset and the recording of depreciation expense is recognized by the including net plant in service in rate base.

Q. DOES INCLUSION OF PLANT IN SERVICE IN RATE BASE SUFFICE TO PROPERLY ACCOUNT FOR THE ENTIRE LAG RELATING TO DEPRECIATION?

A. No. The inclusion in rate base of plant in service does not recognize the subsequent lag from the provision of service to the receipt of cash for that service. By including depreciation expense in the lead-lag study with a zero expense lag, the lead-lag study properly recognizes the subsequent revenue lag on recovering cash related to investment in plant assets. In other words, the investment in an asset is included in rate base as net plant in service until depreciation is recorded on that asset. Recording depreciation removes the asset from rate base, even though cash has not been received to pay for the service provided by the asset, unless the revenue lag

on depreciation expense is included in cash working capital through the lead-lag study.

Q. DISCUSS THE TREATMENT OF RETURN ON EQUITY IN THE LEAD-LAG STUDY.

A. Similar to depreciation, operating income is earned at the provision of utility service. There is again a revenue lag between the provision of service and the receipt of cash for that service. By including return on equity in the lead-lag study with a zero expense lag, the lead-lag study properly recognizes the subsequent revenue lag on recovering cash related return.

VI. CONCLUSION

Q. DO YOU BELIEVE THAT THE FORECASTED TEST PERIOD COST OF SERVICE COMPONENTS YOU HAVE PRESENTED REPRESENT THE MOST REASONABLE ESTIMATE OF COSTS FOR THE TEST PERIOD USED IN THIS PROCEEDING?

A. Yes. The cost of service forecast for capital structure and the cash working capital component of rate base is the best projection of the Company's future cost of service.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Joe T. Christian, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Joe T. Christian

STATE OF TEXAS

COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Joe T. Christian on this the 23rd day of September, 2024.

Notary Public

My Commission Expires: September 1, 2028

Giselle R Heroy
My Commission Expires
9/1/2028
Notary ID130804842

Atmos Enery Corporation
Capital Structure (including short-term debt)
For FY 2019 Q1 (12/2018) FY 2024 Q3 (June 2024)

		Capitalization Percentage			
Line #	Quarter Ended	Equity	Long-Term Debt	Short-Term Debt	Total Capitalization
	(a)	(b)	(c)	(d)	(e)
1	Dec-18	59.4%	40.6%	0.00%	100.0%
2	Mar-19	60.1%	39.9%	0.00%	100.0%
3	Jun-19	60.2%	39.0%	0.80%	100.0%
4	Sep-19	59.0%	36.2%	4.77%	100.0%
5	Dec-19	58.6%	41.4%	0.00%	100.0%
6	Mar-20	58.2%	39.9%	1.85%	100.0%
7	Jun-20	58.8%	41.2%	0.00%	100.0%
8	Sep-20	60.0%	40.0%	0.00%	100.0%
9	Dec-20	58.5%	41.5%	0.00%	100.0%
10	Mar-21	60.4%	39.6%	0.00%	100.0%
11	Jun-21	60.3%	39.7%	0.00%	100.0%
12	Sep-21	60.7%	39.3%	0.00%	100.0%
13	Dec-21	59.2%	40.8%	0.00%	100.0%
14	Mar-22	61.1%	38.9%	0.00%	100.0%
15	Jun-22	61.9%	38.1%	0.00%	100.0%
16	Sep-22	61.5%	37.3%	1.21%	100.0%
17	Dec-22	60.2%	39.8%	0.00%	100.0%
18	Mar-23	61.1%	38.9%	0.00%	100.0%
19	Jun-23	62.0%	38.0%	0.00%	100.0%
20	Sep-23	61.7%	36.9%	1.37%	100.0%
21	Dec-23	60.4%	39.6%	0.00%	100.0%
22	Mar-24	61.1%	38.9%	0.00%	100.0%
23	Jun-24	61.2%	38.8%	0.00%	100.0%
24					
25	23 Q Simple Average	60.25%	39.32%	0.435%	
26					
27	Capitalization as of:				
28	Q1 FY 2019	$ 5,348,194,760	$ 3,659,778,860	$ (0)	$ 9,007,973,620
29	Q3 FY 2024	$ 12,183,077,097	$ 7,737,548,982	$ -	$ 19,920,626,079

Atmos Enery Corporation
Authorized Capital Structures
(as of 10/01/2024)

Line #	Division		Case Description	Docket No.	Decision Date	Authorized Capital Structure (Debt / Equity)
	(a)		(b)	(c)	(d)	(e)
1	**APT**		2033 Rate Filing	OS-23-00013758	12/13/2023	40 / 60
2	**Colorado**		2022 Rate Filing	22AL-0348G	5/14/2023	42-45 / 58-55
3	**Kansas**		2022 Rate Filing	23-ATMG-359-RTS	5/9/2023	[1]
4	**Kentucky**		2021 Rate Filing	2021-00214	5/19/2022	44.5 / 54.5
5	**Louisiana**		2023 RSC	U-37185	8/14/2023	42 / 58
6	**Mid-Tex**	**Dallas Only**	2023 DARR	Ord. 32732	5/22/2024	40 / 60
7		**Mid-Tex Cities**	2023 RRM	NA	10/1/2024	42 / 58
8		**Mid-Tex Environs**	2017 SOI	GUD 10742	12/11/2018	40 / 60
9	**Mississippi**		2024 SRF	2005-UN-0503	12/1/2023	39 / 61
10			2024 SIR	2015-UN-049	12/1/2023	39 / 61
11	**Tennessee**		2023 ARM	24-00006	6/01/2014	38 / 62
12	**Virginia**		2023 Rate Filing	PUE-2023-00008	12/1/2023	39 / 61
13	**West Texas**	**WT Cities**	2023 RRM	NA	10/1/2024	42 / 58
14		**WT Environs**	2017 SOI	GUD 10743	12/11/2018	40 / 60
15	**[1] Actual capital structure requested was 38/62; No stated capital structure in settlement.**					

Atmos Enery Corporation
Summary of Capital Recovery Tariffs
(As of September 2024)

							Infrastructure Replacement Only Tracker			Tracker for all Capital Spending				
Line #		**Jurisdiction**	**Comprehensive Formula Rate Making /Annual Rate Review**	**Capital Investment Lag, months [1]**	**Comprehensive Rate Case (no set filing frequency) [2]**	**Capital Investment Lag, months [1]**	**Special Capital Treatment in Annual Review Mechanism**	**Capital Investment Lag, months [1]**	**Stand-alone Rate Treatment**	**Capital Investment Lag, months [1]**	**Stand-alone Rate Treatment**	**Capital Investment Lag, months [1]**	**Limitations on Special Capital Treatment/ Tracker Recovery**	**Limitations on Recovery through General Rate Case or Comprehensive Annual Mechanism**
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1		Colorado	N		Y	24+			Y	0			Y[11]	N
2		Kansas (GSRS)	N		Y	17+			Y (GSRS) [3]	11			Y[12]	N
3		Kansas (SIP)	N		Y	17+			Y	11			Y[13]	N
4		**Kentucky**	**N**		**Y**	**0+**			**Y**	**0**			**Y[14]**	**Y[16]**
5		Louisiana	Y	12			Y	0					N[15]	N
6		Mississippi	Y	0			Y	0					N	N
7		Tennessee	Y	14			Y	0					N	N
8		Texas - Mid-Tex ACSC Cities [6]	Y	15			Y	0					N	N
9		Texas - Mid-Tex ATM Cities	N		Y	15+			Y	0	Y (GRIP) [5]	11	N	N
10		Texas - Mid-Tex-Dallas	Y	14			Y	0					N	N
11		Texas - Mid-Tex (Unincorporated Areas)	N		Y	15+			Y	0	Y (GRIP) [5]	11	N	N
12		Texas - West Texas [7]	Y	15			Y	0					N	N
13		Texas - West Texas (Unincorporated Area	N		Y	15+			Y	0	Y (GRIP) [5]	11	N	N
14		Texas - W Tx (Amarillo, Lubbock) [8]	N		Y [9]	15+			Y	0	Y (GRIP) [5]	11	N	N
15		Virginia	N		Y [10]	6+							N	N
16		Virginia SAVE	N						Y	0			N	N

Notes:

Y	Atmos Energy utilizes a specific tariff, rule, or statute in the jurisdiction
N	Atmos Energy has no specific tariff, rule, or statute in the jurisdiction
1	For purposes of this chart, the number of months between the rate effective period and the respective test period (or evaluation period).
2	These areas are currently dependent on periodic comprehensive rate case filings. Lag shown excludes the period between case test periods.
3	GSRS limits the increase to $0.80 per residential customer per month
4	not used
5	Available by statute, used currently in areas with Railroad Commission as primary jurisdiction and ATM Cities, Amarillo, Lubbock, Dalhart, and Channing.
6	All cities except City of Dallas and ATM Cities
7	All cities except Cities of Amarillo, Lubbock, Dalhart and Channing
8	Also includes Cities of Dalhart and Channing
9	Based upon resolution with the Cities; if appealed to the Railroad Commission, lag could be 21 months
10	May file expedited annual rate adjustment. Includes ability to implement interim rates
11	revenue increase for Atmos Energy's sales customers shall not exceed 2.5% of the total revenues from sales customers for the 12 months ending four months prior to each annual filing
12	statutory cap on the rate impact of GSRS investment of $.80 / residential customer per year
13	$35 million budget over first 5 years of program; Atmos Energy requesting $75 million budget over five years in renewal filing
14	currently limited to $30 million per year
15	Atmos Energy agreed to a budget for 3-year period of $322 million for specific replacement projects based on the needs of the system; no limitation on functionals and public improvement projects

Atmos Energy Corporation
LEAD/LAG STUDY

Company Name:	Atmos Energy Corporation
Jurisdiction:	Kentucky
Base Period:	31-Dec-24
Forecast Test Year:	31-Mar-26
Test Year for Lead/Lag Study:	30-Jun-24

ATO-CWC1 A

Atmos Energy Corporation-Kentucky
Cash Working Capital Lead/Lag Analysis
For Forecast Test Year Ended March 31, 2026

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lead	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)	(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense								
2	Purchased Gas	87,640,898	240,112	*CWC2*	34.63	*CWC3*	39.49	(4.86)	(1,166,944)
3									
4	Operation and Maintenance Expense								
5	O&M, Labor	14,070,026	38,548	*CWC2*	34.63	*CWC4*	14.33	20.30	782,524
6	O&M, Non-Labor	19,602,496	53,705	*CWC2*	34.63	*CWC5*	23.74	10.89	584,940
7	Total O&M Expense	33,672,523							1,367,464
8									
9	Taxes Other Than Income								
10	Ad Valorem	12,385,072	33,932	*CWC2*	34.63	*CWC6*	278.99	(244.36)	(8,291,572)
11	Taxes Property and Other	1,102	3	*CWC2*	34.63	*CWC6*	58.82	(24.19)	(73)
12	Payroll Taxes	375,952	1,030	*CWC2*	34.63	*CWC6*	13.68	20.95	21,578
13	Franchise and other pass through	9,795,658	26,837	*CWC2*	34.63	*CWC6*	40.37	(5.74)	(154,173)
14	Public Service Commission	346,856	950	*CWC2*	34.63	*CWC6*	(186.50)	221.13	210,074
15	DOT	232,790	638	*CWC2*	34.63	*CWC6*	59.00	(24.37)	(15,548)
16									
17	Allocated Taxes-Shared Services								
18	Ad Valorem	50,549	138	*CWC2*	34.63	*CWC6*	213.50	(178.87)	(24,684)
19	Payroll Taxes	299,774	821	*CWC2*	34.63	*CWC6*	13.68	20.95	17,199
20									
21	Allocated Taxes-Business Unit								
22	Ad Valorem		0	*CWC2*	34.63	*CWC6*	278.99	(244.36)	0
23	Payroll Taxes	94,109	258	*CWC2*	34.63	*CWC6*	13.68	20.95	5,405
24	Total Taxes Other Than Income	23,581,862							(8,231,794)
25									
26	Federal Income Tax	*11,097,902*							
27	Current Taxes	0	0	*CWC2*	34.63	*CWC7*	38.25	(3.62)	0
28	Deferred Taxes	11,097,902	30,405	*CWC2*	34.63	*CWC7*	0.00	34.63	1,052,925
29									
30	State Income Tax	2,832,552							
31	Current Taxes	0	0	*CWC2*	34.63	*CWC8*	38.25	(3.62)	0
32	Deferred Taxes	2,832,552	7,760	*CWC2*	34.63	*CWC8*	0.00	34.63	268,729
33									
34	Depreciation	22,028,375	60,352	*CWC2*	34.63		0	34.63	2,089,990
35									
36	Interest Expense - STD	188,470	516	*CWC2*	34.63	*(1)*	19.40	15.23	7,859
37									
38	Interest Expense - LTD	10,051,880	27,539	*CWC2*	34.63	*CWC9*	91.40	(56.77)	(1,563,422)
39									
40	Return on Equity	41,903,174	114,803	*CWC2*	34.63		0	34.63	3,975,628
41									
42	TOTAL	232,997,636							(2,199,566)
43									

44 (1) Please see prior case relied file labeled "CWC1 STD Days Outstanding.pdf (Page 9)" for calculation of average days held

ATO-CWC1 B

Atmos Energy Corporation-Kentucky
Cash Working Capital Lead/Lag Analysis
For Base Period Ended December 31, 2024

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 366 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)	(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense								
2	Purchased Gas	52,986,727	144,772	*CWC2*	34.63	*CWC3*	39.49	(4.86)	(703,594)
3									
4	Operation and Maintenance Expense								
5	O&M, Labor	12,503,414	34,162	*CWC2*	34.63	*CWC4*	14.33	20.30	693,495
6	O&M, Non-Labor	21,033,513	57,469	*CWC2*	34.63	*CWC5*	23.74	10.89	625,932
7	Total O&M Expense	33,536,927							1,319,428
8									
9	Taxes Other Than Income								
10	Ad Valorem	11,322,473	30,936	*CWC2*	34.63	*CWC6*	278.99	(244.36)	(7,559,406)
11	Taxes Property and Other	1,103	3	*CWC2*	34.63	*CWC6*	58.82	(24.19)	(73)
12	Payroll Taxes	391,151	1,069	*CWC2*	34.63	*CWC6*	13.68	20.95	22,389
13	Franchise and other pass through	9,795,658	26,764	*CWC2*	34.63	*CWC6*	40.37	(5.74)	(153,754)
14	Public Service Commission	302,323	826	*N/A*	0.00	*CWC6*	(186.50)	186.50	154,053
15	DOT	237,690	649	*CWC2*	34.63	*CWC6*	59.00	(24.37)	(15,826)
16									
17	Allocated Taxes-Shared Services								
18	Ad Valorem	56,976	156	*CWC2*	34.63	*CWC6*	213.50	(178.87)	(27,845)
19	Payroll Taxes	366,921	1,003	*CWC2*	34.63	*CWC6*	13.68	20.95	21,002
20									
21	Allocated Taxes-Business Unit								
22	Ad Valorem		0	*CWC2*	34.63	*CWC6*	278.99	(244.36)	0
23	Payroll Taxes	163,558	447	*CWC2*	34.63	*CWC6*	13.68	20.95	9,362
24	Total Taxes Other Than Income	22,637,853							(7,550,099)
25									
26	Federal Income Tax	6,081,245							
27	Current Taxes	0	0	*CWC2*	34.63	*CWC7*	38.25	(3.62)	0
28	Deferred Taxes	6,081,245	16,615	*CWC2*	34.63	*CWC7*	0.00	34.63	575,392
29									
30	State Income Tax	320,066							
31	Current Taxes	0	0	*CWC2*	34.63	*CWC8*	38.25	(3.62)	0
32	Deferred Taxes	320,066	874	*CWC2*	34.63	*CWC8*	0.00	34.63	30,284
33									
34	Depreciation	19,915,761	54,415	*CWC2*	34.63		0	34.63	1,884,379
35									
36	Interest Expense - STD	187,551	512	*CWC2*	34.63	*(1)*	19.40	15.23	7,804
37									
38	Interest Expense - LTD	9,627,625	26,305	*CWC2*	34.63	*CWC9*	91.40	(56.77)	(1,493,365)
39									
40	Return on Equity	41,698,868	113,931	*CWC2*	34.63		0	34.63	3,945,442
41									
42	TOTAL	186,992,623							(1,984,329)
43									

44 (1) Please see relied file labeled "CWC1 STD Days Outstanding.pdf (Page 9)" for calculation of average days held

ATO-CWC2

Atmos Energy Corporation-Kentucky
Revenue Lag Study
For Base Period Ended June 30, 2024

Line No.	Description	Weighted Average Lag
	(a)	(b)
1	**Average Billing Lag (1) =**	0.31
2		
3	**Service Lag =**	15.25
4		
5	**Collection Lag:**	18.07
6	(Test Yr Average Daily Accounts Receivable / Test Yr Average Daily Revenue)	
7		
8	**Bank Lag (2) =**	1.00
9		
10	**Total Revenue Lag =**	34.63
11		
12	Notes:	
13	(1) Please see the relied upon labeled "CWC2 Read to Billing Lag" for the billing lag	
14	for the months of August 2023 and November 2023.	
15	(2) Company pay channels average one day between customer remittance and funds deposited to Company account.	

Atmos Energy Corporation-Kentucky CWC WP 2-1
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For Base Period Ended June 30, 2024

Line No.	Date	Total
1	07/01/2023	6,086,985.74
2	07/02/2023	6,035,915.17
3	07/03/2023	5,623,055.29
4	07/04/2023	5,292,232.46
5	07/05/2023	4,952,095.30
6	07/06/2023	4,819,279.99
7	07/07/2023	4,865,995.20
8	07/08/2023	4,838,148.16
9	07/09/2023	4,799,836.75
10	07/10/2023	4,319,384.78
11	07/11/2023	3,311,596.36
12	07/12/2023	3,397,021.44
13	07/13/2023	3,581,637.93
14	07/14/2023	3,838,187.48
15	07/15/2023	3,807,365.10
16	07/16/2023	3,762,168.57
17	07/17/2023	3,704,179.40
18	07/18/2023	3,894,184.36
19	07/19/2023	4,177,732.13
20	07/20/2023	6,012,011.80
21	07/21/2023	6,152,906.28
22	07/22/2023	6,116,443.72
23	07/23/2023	6,074,259.85
24	07/24/2023	6,068,838.63
25	07/25/2023	6,150,854.21
26	07/26/2023	6,206,735.68
27	07/27/2023	6,442,497.10
28	07/28/2023	6,331,748.12
29	07/29/2023	6,287,901.07
30	07/30/2023	6,239,996.71
31	07/31/2023	5,535,028.89
32	08/01/2023	5,238,000.90
33	08/02/2023	5,127,636.45
34	08/03/2023	5,170,421.69
35	08/04/2023	5,175,285.78
36	08/05/2023	5,156,014.46
37	08/06/2023	5,116,077.44
38	08/07/2023	4,514,705.15
39	08/08/2023	4,285,163.51
40	08/09/2023	4,129,177.24
41	08/10/2023	4,284,278.35
42	08/11/2023	4,569,912.97
43	08/12/2023	4,534,463.44
44	08/13/2023	4,499,982.06
45	08/14/2023	4,095,898.30
46	08/15/2023	3,374,260.08
47	08/16/2023	3,595,066.74
48	08/17/2023	5,879,220.08
49	08/18/2023	6,138,750.17
50	08/19/2023	6,096,557.74
51	08/20/2023	6,061,492.92
52	08/21/2023	5,973,210.65
53	08/22/2023	5,909,589.94
54	08/23/2023	6,115,068.22
55	08/24/2023	6,302,382.02
56	08/25/2023	6,500,920.45
57	08/26/2023	6,474,922.88
58	08/27/2023	6,434,781.92

Atmos Energy Corporation-Kentucky CWC WP 2-1
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For Base Period Ended June 30, 2024

Line No.	Date	Total
59	08/28/2023	5,953,376.80
60	08/29/2023	5,599,876.59
61	08/30/2023	5,064,151.62
62	08/31/2023	4,881,377.41
63	09/01/2023	5,025,645.06
64	09/02/2023	5,003,267.93
65	09/03/2023	4,983,741.31
66	09/04/2023	4,954,726.11
67	09/05/2023	4,399,355.89
68	09/06/2023	4,031,009.88
69	09/07/2023	4,340,216.14
70	09/08/2023	4,477,981.95
71	09/09/2023	4,468,548.16
72	09/10/2023	4,447,230.01
73	09/11/2023	3,968,783.74
74	09/12/2023	2,855,169.68
75	09/13/2023	3,036,967.12
76	09/14/2023	3,240,106.60
77	09/15/2023	3,537,215.96
78	09/16/2023	3,501,716.86
79	09/17/2023	3,462,874.90
80	09/18/2023	3,733,591.13
81	09/19/2023	4,051,695.04
82	09/20/2023	5,763,764.10
83	09/21/2023	5,906,010.02
84	09/22/2023	6,150,109.46
85	09/23/2023	6,111,406.63
86	09/24/2023	6,064,825.65
87	09/25/2023	6,102,176.78
88	09/26/2023	6,021,384.66
89	09/27/2023	6,067,936.52
90	09/28/2023	5,974,125.01
91	09/29/2023	5,778,106.84
92	09/30/2023	5,721,433.31
93	10/01/2023	5,672,639.46
94	10/02/2023	5,181,133.77
95	10/03/2023	5,013,419.69
96	10/04/2023	4,975,072.82
97	10/05/2023	5,037,872.92
98	10/06/2023	5,194,371.19
99	10/07/2023	5,175,374.74
100	10/08/2023	5,142,928.56
101	10/09/2023	5,120,591.84
102	10/10/2023	4,465,198.65
103	10/11/2023	4,485,866.82
104	10/12/2023	4,643,311.09
105	10/13/2023	4,129,159.09
106	10/14/2023	4,100,094.17
107	10/15/2023	4,057,896.92
108	10/16/2023	3,830,259.15
109	10/17/2023	3,928,566.36
110	10/18/2023	5,997,073.22
111	10/19/2023	6,271,410.75
112	10/20/2023	6,476,841.82
113	10/21/2023	6,442,258.04
114	10/22/2023	6,399,214.47
115	10/24/2023	6,362,915.28
116	10/25/2023	6,451,432.99
117	10/26/2023	6,658,914.17

Atmos Energy Corporation-Kentucky CWC WP 2-1
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For Base Period Ended June 30, 2024

Line No.	Date	Total
118	10/27/2023	6,635,805.68
119	10/28/2023	6,596,091.87
120	10/29/2023	6,545,040.56
121	10/30/2023	5,950,840.71
122	10/31/2023	5,430,520.24
123	11/01/2023	5,383,202.33
124	11/02/2023	5,562,526.31
125	11/03/2023	5,775,663.50
126	11/04/2023	5,737,610.18
127	11/05/2023	5,716,043.14
128	11/06/2023	5,386,154.09
129	11/07/2023	5,029,891.98
130	11/08/2023	4,913,887.26
131	11/09/2023	5,679,257.30
132	11/10/2023	5,986,624.94
133	11/11/2023	5,128,778.13
134	11/12/2023	5,088,746.30
135	11/13/2023	5,105,457.09
136	11/14/2023	5,133,514.41
137	11/15/2023	5,569,499.14
138	11/16/2023	8,225,315.58
139	11/17/2023	8,651,721.49
140	11/18/2023	8,587,548.86
141	11/19/2023	8,537,243.41
142	11/20/2023	8,575,386.83
143	11/21/2023	8,849,090.99
144	11/22/2023	9,228,108.52
145	11/23/2023	9,102,597.87
146	11/24/2023	9,030,450.70
147	11/25/2023	8,935,865.72
148	11/26/2023	8,874,303.83
149	11/27/2023	8,706,633.13
150	11/28/2023	8,659,855.88
151	11/29/2023	8,148,211.67
152	11/30/2023	7,839,590.69
153	12/01/2023	8,108,206.73
154	12/02/2023	8,037,187.69
155	12/03/2023	7,960,439.21
156	12/04/2023	7,490,768.21
157	12/05/2023	7,114,212.40
158	12/06/2023	7,184,182.86
159	12/07/2023	7,645,327.00
160	12/08/2023	8,116,639.90
161	12/09/2023	8,066,230.51
162	12/10/2023	7,995,321.87
163	12/11/2023	7,789,610.41
164	12/12/2023	7,096,998.41
165	12/13/2023	7,847,890.71
166	12/14/2023	9,530,007.76
167	12/15/2023	12,199,155.05
168	12/16/2023	12,105,556.23
169	12/17/2023	12,026,957.32
170	12/18/2023	11,954,741.63
171	12/19/2023	12,201,337.68
172	12/20/2023	12,728,990.90
173	12/21/2023	13,500,437.49
174	12/22/2023	13,969,798.36
175	12/23/2023	13,874,290.84
176	12/24/2023	13,799,144.60

Atmos Energy Corporation-Kentucky CWC WP 2-1
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For Base Period Ended June 30, 2024

Line No.	Date	Total
177	12/25/2023	13,681,845.81
178	12/26/2023	13,191,383.03
179	12/27/2023	12,583,488.86
180	12/28/2023	11,536,300.49
181	12/29/2023	10,997,002.44
182	12/30/2023	10,953,955.96
183	12/31/2023	10,922,786.58
184	01/01/2024	10,822,154.79
185	01/02/2024	9,719,777.09
186	01/03/2024	8,433,666.25
187	01/04/2024	8,703,311.12
188	01/05/2024	8,964,844.52
189	01/06/2024	8,927,518.72
190	01/07/2024	8,850,274.46
191	01/08/2024	8,146,054.56
192	01/09/2024	6,610,275.75
193	01/10/2024	6,832,829.38
194	01/11/2024	7,564,253.00
195	01/12/2024	8,539,850.79
196	01/13/2024	8,468,411.80
197	01/14/2024	8,392,755.35
198	01/15/2024	8,077,098.53
199	01/16/2024	8,561,573.61
200	01/17/2024	9,239,953.64
201	01/18/2024	10,556,879.89
202	01/19/2024	13,560,003.24
203	01/20/2024	13,510,450.34
204	01/21/2024	13,379,262.79
205	01/22/2024	13,698,254.83
206	01/23/2024	13,924,002.73
207	01/24/2024	14,771,360.73
208	01/25/2024	15,996,126.64
209	01/26/2024	16,863,979.21
210	01/27/2024	16,732,464.06
211	01/28/2024	16,587,562.73
212	01/29/2024	16,794,390.89
213	01/30/2024	15,511,764.04
214	01/31/2024	14,428,708.89
215	02/01/2024	14,664,670.99
216	02/02/2024	14,961,705.93
217	02/03/2024	14,812,073.86
218	02/04/2024	14,731,428.26
219	02/05/2024	14,443,888.47
220	02/06/2024	13,730,161.25
221	02/07/2024	13,431,750.11
222	02/08/2024	13,100,544.45
223	02/09/2024	13,693,191.90
224	02/10/2024	13,534,058.79
225	02/11/2024	13,396,588.39
226	02/12/2024	12,565,995.57
227	02/13/2024	11,888,023.23
228	02/14/2024	11,262,371.62
229	02/15/2024	11,788,358.08
230	02/16/2024	12,664,386.60
231	02/17/2024	12,520,531.06
232	02/18/2024	12,412,979.21
233	02/19/2024	13,036,318.84
234	02/20/2024	14,858,812.72
235	02/21/2024	14,854,500.49

Atmos Energy Corporation-Kentucky CWC WP 2-1
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For Base Period Ended June 30, 2024

Line No.	Date	Total
236	02/22/2024	15,202,585.03
237	02/23/2024	16,007,866.22
238	02/24/2024	15,890,143.77
239	02/25/2024	15,748,063.98
240	02/26/2024	15,073,204.73
241	02/27/2024	14,700,882.19
242	02/28/2024	13,951,090.86
243	02/29/2024	13,380,414.33
244	03/01/2024	13,592,652.29
245	03/02/2024	13,453,482.32
246	03/03/2024	13,332,817.77
247	03/04/2024	11,958,625.98
248	03/05/2024	11,159,325.92
249	03/06/2024	10,863,109.37
250	03/07/2024	11,385,537.78
251	03/08/2024	11,687,444.58
252	03/09/2024	11,602,247.89
253	03/10/2024	11,489,781.01
254	03/11/2024	10,728,465.47
255	03/12/2024	10,195,381.75
256	03/13/2024	10,085,975.05
257	03/14/2024	10,028,840.37
258	03/15/2024	9,586,352.09
259	03/16/2024	9,483,151.63
260	03/17/2024	9,406,907.38
261	03/18/2024	11,241,356.02
262	03/19/2024	11,265,286.09
263	03/20/2024	11,295,674.75
264	03/21/2024	11,554,126.30
265	03/22/2024	12,196,249.72
266	03/23/2024	12,118,980.47
267	03/24/2024	12,028,802.55
268	03/25/2024	11,416,586.63
269	03/26/2024	11,088,162.99
270	03/27/2024	10,500,256.61
271	03/28/2024	10,036,340.35
272	03/29/2024	9,946,043.80
273	03/30/2024	9,858,336.08
274	03/31/2024	9,785,389.78
275	04/01/2024	8,662,591.59
276	04/02/2024	8,031,550.81
277	04/03/2024	7,756,766.51
278	04/04/2024	7,733,597.51
279	04/05/2024	7,903,379.46
280	04/06/2024	7,844,434.26
281	04/07/2024	7,783,319.89
282	04/08/2024	7,064,146.73
283	04/09/2024	6,528,216.17
284	04/10/2024	6,394,651.75
285	04/11/2024	5,990,199.43
286	04/12/2024	6,489,237.72
287	04/13/2024	6,424,937.85
288	04/14/2024	6,359,655.84
289	04/15/2024	9,264,122.80
290	04/16/2024	9,589,954.48
291	04/17/2024	10,044,318.51
292	04/18/2024	10,421,998.39
293	04/19/2024	10,722,256.10
294	04/20/2024	10,650,011.57

Atmos Energy Corporation-Kentucky CWC WP 2-1
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For Base Period Ended June 30, 2024

Line No.	Date	Total
295	04/21/2024	10,578,442.26
296	04/22/2024	10,117,116.64
297	04/23/2024	10,209,286.79
298	04/24/2024	10,312,468.23
299	04/25/2024	10,557,162.63
300	04/26/2024	10,406,315.99
301	04/27/2024	10,342,341.00
302	04/28/2024	10,233,656.69
303	04/29/2024	9,298,816.68
304	04/30/2024	8,258,734.22
305	05/01/2024	7,905,001.06
306	05/02/2024	7,605,199.90
307	05/03/2024	7,591,228.14
308	05/04/2024	7,566,125.72
309	05/05/2024	7,532,018.08
310	05/06/2024	6,700,312.46
311	05/07/2024	6,099,093.38
312	05/08/2024	5,929,072.77
313	05/09/2024	4,327,803.89
314	05/10/2024	4,612,716.51
315	05/11/2024	4,567,195.78
316	05/12/2024	4,530,828.26
317	05/13/2024	4,227,661.64
318	05/14/2024	5,854,393.25
319	05/15/2024	5,966,094.09
320	05/16/2024	6,309,495.61
321	05/17/2024	6,655,277.20
322	05/18/2024	6,618,720.46
323	05/19/2024	6,582,070.78
324	05/20/2024	6,632,869.50
325	05/21/2024	6,624,877.16
326	05/22/2024	6,595,633.03
327	05/23/2024	6,904,494.44
328	05/24/2024	7,095,139.13
329	05/25/2024	7,021,558.91
330	05/26/2024	7,007,492.82
331	05/27/2024	6,985,779.79
332	05/28/2024	6,564,614.78
333	05/29/2024	6,073,207.94
334	05/30/2024	5,822,735.82
335	05/31/2024	5,375,249.32
336	06/01/2024	5,352,383.56
337	06/02/2024	5,305,902.63
338	06/03/2024	4,680,282.86
339	06/04/2024	4,205,440.25
340	06/05/2024	3,985,380.53
341	06/06/2024	4,057,447.40
342	06/07/2024	3,469,314.47
343	06/08/2024	3,437,445.31
344	06/09/2024	3,385,458.24
345	06/10/2024	3,214,879.43
346	06/11/2024	3,068,407.21
347	06/12/2024	3,134,083.91
348	06/13/2024	3,367,008.74
349	06/14/2024	3,651,163.46
350	06/15/2024	3,617,827.37
351	06/16/2024	3,581,080.07
352	06/17/2024	3,643,874.51
353	06/18/2024	3,847,916.24

Atmos Energy Corporation-Kentucky CWC WP 2-1
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For Base Period Ended June 30, 2024

Line No.	Date	Total	
354	06/19/2024	4,160,408.89	
355	06/20/2024	4,364,774.50	
356	06/21/2024	4,588,755.76	
357	06/22/2024	4,549,210.46	
358	06/23/2024	4,513,304.91	
359	06/24/2024	6,399,042.97	
360	06/25/2024	6,398,147.27	
361	06/26/2024	6,398,148.40	
362	06/27/2024	6,337,377.98	
363	06/28/2024	6,158,610.52	
364	06/29/2024	6,111,659.46	
365	06/30/2024	6,066,250.22	
366			
367	AVERAGE DAILY TOTALS	7,809,992.33	
368			
369	KENTUCKY ANNUAL BILLED REVENUE	157,752,777	From WP 2-2
370	KENTUCKY AVERAGE DAILY REVENUE	432,199	
371			
372	REVENUE LAG	18.07	

Atmos Energy Corporation-Kentucky

CWC WP 2-2

Revenue Lag Study - Division 009 Kentucky Monthly Revenues

For Base Period Ended June 30, 2024

Account	Description	JUL-23	AUG-23	SEP-23	OCT-23	NOV-23	DEC-23	JAN-24	FEB-24	MAR-24	APR-24	MAY-24	JUN-24	Total
4800	Residential sales	(3,784,074)	(3,729,999)	(3,800,704)	(4,075,146)	(6,697,889)	(10,243,104)	(14,522,204)	(13,210,657)	(9,497,697)	(7,469,105)	(4,669,379)	(4,016,962)	(85,716,919)
4811	Commercial Revenue	(2,031,076)	(1,812,662)	(2,081,766)	(2,343,567)	(3,197,879)	(4,714,940)	(6,903,467)	(6,188,916)	(4,359,660)	(3,450,356)	(2,269,478)	(2,019,915)	(41,373,682)
4812	Industrial Revenue	(135,181)	(155,986)	(142,696)	(157,162)	(305,665)	(485,608)	(744,308)	(650,415)	(439,262)	(338,109)	(376,430)	(159,623)	(4,090,444)
4820	Other Sales to Public Authority	(233,247)	(211,315)	(209,482)	(267,276)	(444,626)	(672,496)	(993,050)	(903,357)	(625,180)	(473,388)	(325,266)	(235,203)	(5,593,886)
4870	Forfeited discounts	0	0	0	0	0	0	0	(27,026)	(26,264)	(19,782)	(14,419)	(11,956)	(99,447)
4880	Miscellaneous service revenues	(8,490)	80,093	(4,212)	(9,928)	(8,550)	(4,906)	(5,587)	(4,026)	(4,332)	(3,439)	(3,844)	(3,004)	19,775
4893	Revenue-Transportation Distrib	(1,408,979)	(1,499,881)	(1,501,920)	(1,775,143)	(1,854,319)	(1,896,774)	(2,205,449)	(1,919,454)	(2,254,677)	(1,324,758)	(1,662,340)	(1,594,478)	(20,898,173)
Billed Revenue		**(7,601,048)**	**(7,329,750)**	**(7,740,780)**	**(8,628,222)**	**(12,508,928)**	**(18,017,827)**	**(25,374,065)**	**(22,903,850)**	**(17,207,073)**	**(13,078,936)**	**(9,321,156)**	**(8,041,142)**	**(157,752,777)**
	Billed Taxes													-
Billed Revenue plus Taxes		**(7,601,048)**	**(7,329,750)**	**(7,740,780)**	**(8,628,222)**	**(12,508,928)**	**(18,017,827)**	**(25,374,065)**	**(22,903,850)**	**(17,207,073)**	**(13,078,936)**	**(9,321,156)**	**(8,041,142)**	**(157,752,777)**
4805	Unbilled Residential Revenue	83,915	7,369	37,498	(1,068,406)	(2,258,789)	(1,115,156)	(941,607)	1,662,235	1,038,979	2,112,813	492,713	31,587	83,151
4815	Unbilled Comm Revenue	80,640	10,787	34,029	(435,641)	(889,284)	(613,567)	(386,848)	747,403	507,331	859,772	136,563	31,939	83,124
4816	Unbilled Indus Revenue	(4,453)	2,372	2,208	(15,862)	(35,310)	3,291	9,492	(7,351)	3,459	(21,741)	40,244	10,207	(13,443)
4825	Unbilled Public Authority Reve	11,234	285	4,018	(83,073)	(164,393)	(88,066)	(66,618)	121,281	77,501	156,195	45,481	3,727	17,572
4960	Cost of Service Reserve													-
Unbilled Revenue		**171,336**	**20,813**	**77,753**	**(1,602,981)**	**(3,347,776)**	**(1,813,499)**	**(1,385,580)**	**2,523,568**	**1,627,270**	**3,107,039**	**715,001**	**77,460**	**170,404**
Total Revenue		**(7,429,711)**	**(7,308,937)**	**(7,663,027)**	**(10,231,203)**	**(15,856,704)**	**(19,831,326)**	**(26,759,645)**	**(20,380,282)**	**(15,579,802)**	**(9,971,897)**	**(8,606,156)**	**(7,963,682)**	**(157,582,373)**

Atmos Energy Corporation-Kentucky
Per Books Purchase Gas Cost
For Base Period Ended June 30, 2024

ATO-CWC3

Line No.	Supplier	Production Month Start Service	Production Month Finish Service	Service Lag	Date of Invoice	Invoice Lag	Date Paid	Payment Lag	Total Lag	Amount	$ Days (h) x (i)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Antle Operating Company Inc.	06/01/23	06/30/23	15.00	07/12/23	12.00	07/19/23	7.00	34.00	$ 1,129.09	$ 38,389.06
2	Midwestern Gas Transmission	06/01/23	06/30/23	15.00	07/12/23	12.00	07/20/23	8.00	35.00	1,946.46	68,126.10
3	Orbit Gas Transmission Inc	06/01/23	06/30/23	15.00	07/13/23	13.00	07/19/23	6.00	34.00	8,331.47	283,269.98
4	Symmetry Energy Solutions, LLC	06/01/23	06/30/23	15.00	07/21/23	21.00	07/25/23	4.00	40.00	61,320.08	2,452,803.20
5	Symmetry Energy Solutions, LLC	06/01/23	06/30/23	15.00	07/21/23	21.00	07/25/23	4.00	40.00	2,549,139.80	101,965,592.00
6	Tennessee Gas Pipeline Co	06/01/23	06/30/23	15.00	07/14/23	14.00	07/24/23	10.00	39.00	170,082.05	6,633,199.95
7	Texas Gas Transmission Corporatio	06/01/23	06/30/23	15.00	07/12/23	12.00	07/24/23	12.00	39.00	1,213,343.10	47,320,380.90
8	Trunkline Gas Company, LLC	06/01/23	06/30/23	15.00	07/12/23	12.00	07/20/23	8.00	35.00	6,650.24	232,758.40
9	United Energy Trading, LLC	06/01/23	06/30/23	15.00	07/20/23	20.00	07/25/23	5.00	40.00	346,246.72	13,849,868.80
10	Antle Operating Company Inc.	07/01/23	07/31/23	15.50	08/10/23	10.00	08/14/23	4.00	29.50	2,470.78	72,888.01
11	Midwestern Gas Transmission	07/01/23	07/31/23	15.50	08/09/23	9.00	08/17/23	8.00	32.50	1,753.78	56,997.85
12	Orbit Gas Transmission Inc	07/01/23	07/31/23	15.50	08/10/23	10.00	08/14/23	4.00	29.50	11,579.94	341,608.23
13	Symmetry Energy Solutions, LLC	07/01/23	07/31/23	15.50	08/21/23	21.00	08/25/23	4.00	40.50	74,968.59	3,036,227.90
14	Symmetry Energy Solutions, LLC	07/01/23	07/31/23	15.50	08/22/23	22.00	08/25/23	3.00	40.50	2,937,187.03	118,956,074.72
15	Tennessee Gas Pipeline Co	07/01/23	07/31/23	15.50	08/10/23	10.00	08/21/23	11.00	36.50	170,082.05	6,207,994.83
16	Texas Gas Transmission Corporatio	07/01/23	07/31/23	15.50	08/10/23	10.00	08/21/23	11.00	36.50	1,253,787.87	45,763,257.26
17	Trunkline Gas Company, LLC	07/01/23	07/31/23	15.50	08/10/23	10.00	08/21/23	11.00	36.50	6,873.35	250,877.28
18	United Energy Trading, LLC	07/01/23	07/31/23	15.50	08/16/23	16.00	08/25/23	9.00	40.50	450,341.07	18,238,813.34
19	Antle Operating Company Inc.	08/01/23	08/31/23	15.50	09/19/23	19.00	09/21/23	2.00	36.50	2,135.67	77,951.96
20	Mercuria Energy America, LLC	08/01/23	08/31/23	15.50	09/19/23	19.00	09/25/23	6.00	40.50	13,968.16	565,710.48
21	Midwestern Gas Transmission	08/01/23	08/31/23	15.50	09/13/23	13.00	09/18/23	5.00	33.50	2,130.26	71,363.71
22	Orbit Gas Transmission Inc	08/01/23	08/31/23	15.50	09/19/23	19.00	09/21/23	2.00	36.50	12,361.87	451,208.26
23	Symmetry Energy Solutions, LLC	08/01/23	08/31/23	15.50	09/21/23	21.00	09/25/23	4.00	40.50	71,043.08	2,877,244.74
24	Symmetry Energy Solutions, LLC	08/01/23	08/31/23	15.50	09/21/23	21.00	09/25/23	4.00	40.50	2,962,431.87	119,978,490.74
25	Tennessee Gas Pipeline Co	08/01/23	08/31/23	15.50	09/13/23	13.00	09/25/23	12.00	40.50	170,082.05	6,888,323.03
26	Texas Gas Transmission Corporatio	08/01/23	08/31/23	15.50	09/13/23	13.00	09/22/23	9.00	37.50	1,253,787.87	47,017,045.13
27	Trunkline Gas Company, LLC	08/01/23	08/31/23	15.50	09/15/23	15.00	09/20/23	5.00	35.50	6,876.50	244,115.75
28	United Energy Trading, LLC	08/01/23	08/31/23	15.50	09/20/23	20.00	09/25/23	5.00	40.50	400,719.12	16,229,124.36
29	Antle Operating Company Inc.	09/01/23	09/30/23	15.00	10/09/23	9.00	10/18/23	9.00	33.00	2,142.30	70,695.90
30	Mercuria Energy America, LLC	09/01/23	09/30/23	15.00	10/23/23	23.00	10/25/23	2.00	40.00	24,624.00	984,960.00
31	Orbit Gas Transmission Inc	09/01/23	09/30/23	15.00	10/09/23	9.00	10/12/23	3.00	27.00	8,828.02	238,356.54
32	Symmetry Energy Solutions, LLC	09/01/23	09/30/23	15.00	10/25/23	25.00	10/30/23	5.00	45.00	3,087,181.10	138,923,149.50
33	Symmetry Energy Solutions, LLC	09/01/23	09/30/23	15.00	10/23/23	23.00	10/25/23	2.00	40.00	71,384.85	2,855,394.00
34	Tennessee Gas Pipeline Co	09/01/23	09/30/23	15.00	10/11/23	11.00	10/23/23	12.00	38.00	170,082.05	6,463,117.90
35	Texas Gas Transmission Corporatio	09/01/23	09/30/23	15.00	10/11/23	11.00	10/23/23	12.00	38.00	1,213,343.10	46,107,037.80
36	Trunkline Gas Company, LLC	09/01/23	09/30/23	15.00	10/10/23	10.00	10/20/23	10.00	35.00	6,650.69	232,774.15
37	United Energy Trading, LLC	09/01/23	09/30/23	15.00	10/18/23	18.00	10/25/23	7.00	40.00	442,029.94	17,681,197.60
38	Antle Operating Company Inc.	10/01/23	10/31/23	15.50	11/10/23	10.00	11/20/23	10.00	35.50	2,087.19	74,095.25
39	Mercuria Energy America, LLC	10/01/23	10/31/23	15.50	11/14/23	14.00	11/27/23	13.00	42.50	27,994.44	1,189,763.70
40	Midwestern Gas Transmission	10/01/23	10/31/23	15.50	11/10/23	10.00	11/17/23	7.00	32.50	1,836.27	59,678.78
41	Orbit Gas Transmission Inc	10/01/23	10/31/23	15.50	11/10/23	10.00	11/16/23	6.00	31.50	9,095.24	286,500.06
42	Symmetry Energy Solutions, LLC	10/01/23	10/31/23	15.50	11/20/23	20.00	11/27/23	7.00	42.50	78,891.00	3,352,867.50
43	Symmetry Energy Solutions, LLC	10/01/23	10/31/23	15.50	11/21/23	21.00	11/27/23	6.00	42.50	3,713,431.94	157,820,857.45
44	Tennessee Gas Pipeline Co	10/01/23	10/31/23	15.50	11/13/23	13.00	11/20/23	7.00	35.50	205,396.65	7,291,581.08
45	Texas Gas Transmission Corporatio	10/01/23	10/31/23	15.50	11/13/23	13.00	11/20/23	7.00	35.50	1,642,385.27	58,304,677.09
46	Trunkline Gas Company, LLC	10/01/23	10/31/23	15.50	11/15/23	15.00	11/20/23	5.00	35.50	6,861.59	243,586.45
47	United Energy Trading, LLC	10/01/23	10/31/23	15.50	11/20/23	20.00	11/27/23	7.00	42.50	644,411.60	27,387,493.00
48	Antle Operating Company Inc.	11/01/23	11/30/23	15.00	12/13/23	13.00	12/18/23	5.00	33.00	1,415.35	46,706.55
49	Mercuria Energy America, LLC	11/01/23	11/30/23	15.00	12/13/23	13.00	12/26/23	13.00	41.00	32,559.10	1,334,923.10
50	Orbit Gas Transmission Inc	11/01/23	11/30/23	15.00	12/13/23	13.00	12/14/23	1.00	29.00	3,044.20	88,281.80
51	Symmetry Energy Solutions, LLC	11/01/23	11/30/23	15.00	12/22/23	22.00	12/26/23	4.00	41.00	1,996,092.42	81,839,789.22
52	Symmetry Energy Solutions, LLC	11/01/23	11/30/23	15.00	12/22/23	22.00	12/26/23	4.00	41.00	227,563.20	9,330,091.20

Atmos Energy Corporation-Kentucky
Per Books Purchase Gas Cost
For Base Period Ended June 30, 2024

ATO-CWC3

Line No.	Supplier	Production Month Start Service	Production Month Finish Service	Service Lag	Date of Invoice	Invoice Lag	Date Paid	Payment Lag	Total Lag	Amount	$ Days (h) x (i)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
53	Tennessee Gas Pipeline Co	11/01/23	11/30/23	15.00	12/12/23	12.00	12/22/23	10.00	37.00	377,567.30	13,969,990.10
54	Texas Gas Transmission Corporatio	11/01/23	11/30/23	15.00	12/13/23	13.00	12/21/23	8.00	36.00	1,749,116.70	62,968,201.20
55	Trunkline Gas Company, LLC	11/01/23	11/30/23	15.00	12/11/23	11.00	12/20/23	9.00	35.00	31,952.71	1,118,344.85
56	Trunkline Gas Company, LLC	11/01/23	11/30/23	15.00	12/11/23	11.00	12/20/23	9.00	35.00	9,577.80	335,223.00
57	United Energy Trading, LLC	11/01/23	11/30/23	15.00	12/20/23	20.00	12/27/23	7.00	42.00	188,596.20	7,921,040.40
58	Mercuria Energy America, LLC	12/01/23	12/31/23	15.50	01/18/24	18.00	01/25/24	7.00	40.50	33,601.75	1,360,870.88
59	Midwestern Gas Transmission	12/01/23	12/31/23	15.50	01/16/24	16.00	01/18/24	2.00	33.50	3,261.63	109,264.61
60	Orbit Gas Transmission Inc	12/01/23	12/31/23	15.50	01/18/24	18.00	01/23/24	5.00	38.50	2,335.54	89,918.29
61	Symmetry Energy Solutions, LLC	12/01/23	12/31/23	15.50	01/23/24	23.00	01/25/24	2.00	40.50	169,772.20	6,875,774.10
62	Symmetry Energy Solutions, LLC	12/01/23	12/31/23	15.50	01/23/24	23.00	01/25/24	2.00	40.50	2,578,947.81	104,447,386.31
63	Tennessee Gas Pipeline Co	12/01/23	12/31/23	15.50	01/12/24	12.00	01/22/24	10.00	37.50	386,628.40	14,498,565.00
64	Texas Gas Transmission Corporatio	12/01/23	12/31/23	15.50	01/12/24	12.00	01/22/24	10.00	37.50	1,807,420.59	67,778,272.13
65	Trunkline Gas Company, LLC	12/01/23	12/31/23	15.50	01/18/24	18.00	01/22/24	4.00	37.50	43,750.80	1,640,655.00
66	United Energy Trading, LLC	12/01/23	12/31/23	15.50	01/19/24	19.00	01/25/24	6.00	40.50	102,647.42	4,157,220.51
67	Mercuria Energy America, LLC	01/01/24	01/31/24	15.50	02/16/24	16.00	02/26/24	10.00	41.50	23,502.83	975,367.45
68	Midwestern Gas Transmission	01/01/24	01/31/24	15.50	02/14/24	14.00	02/20/24	6.00	35.50	2,176.18	77,254.39
69	Orbit Gas Transmission Inc	01/01/24	01/31/24	15.50	02/16/24	16.00	02/21/24	5.00	36.50	422.93	15,436.95
70	Symmetry Energy Solutions, LLC	01/01/24	01/31/24	15.50	02/22/24	22.00	02/26/24	4.00	41.50	4,600,874.47	190,936,290.51
71	Symmetry Energy Solutions, LLC	01/01/24	01/31/24	15.50	02/22/24	22.00	02/26/24	4.00	41.50	574,272.83	23,832,322.45
72	Tennessee Gas Pipeline Co	01/01/24	01/31/24	15.50	02/12/24	12.00	02/22/24	10.00	37.50	386,628.40	14,498,565.00
73	Texas Gas Transmission Corporatio	01/01/24	01/31/24	15.50	02/12/24	12.00	02/20/24	8.00	35.50	1,807,420.59	64,163,430.95
74	Trunkline Gas Company, LLC	01/01/24	01/31/24	15.50	02/16/24	16.00	02/20/24	4.00	35.50	43,221.98	1,534,380.29
75	United Energy Trading, LLC	01/01/24	01/31/24	15.50	02/20/24	20.00	02/26/24	6.00	41.50	476,925.96	19,792,427.34
76	Mercuria Energy America, LLC	02/01/24	02/29/24	14.50	03/12/24	12.00	03/25/24	13.00	39.50	25,571.70	1,010,082.15
77	Orbit Gas Transmission Inc	02/01/24	02/29/24	14.50	03/14/24	14.00	03/18/24	4.00	32.50	389.78	12,667.85
78	Symmetry Energy Solutions, LLC	02/01/24	02/29/24	14.50	03/21/24	21.00	03/25/24	4.00	39.50	505,537.52	19,968,732.04
79	Symmetry Energy Solutions, LLC	02/01/24	02/29/24	14.50	03/20/24	20.00	03/25/24	5.00	39.50	149,779.66	5,916,296.57
80	Tennessee Gas Pipeline Co	02/01/24	02/29/24	14.50	03/13/24	13.00	03/22/24	9.00	36.50	375,960.25	13,722,549.13
81	Texas Gas Transmission Corporatio	02/01/24	02/29/24	14.50	03/13/24	13.00	03/21/24	8.00	35.50	1,690,812.81	60,023,854.76
82	Trunkline Gas Company, LLC	02/01/24	02/29/24	14.50	03/12/24	12.00	03/20/24	8.00	34.50	40,288.48	1,389,952.56
83	United Energy Trading, LLC	02/01/24	02/29/24	14.50	03/19/24	19.00	03/25/24	6.00	39.50	88,142.99	3,481,648.11
84	Antle Operating Company Inc.	03/01/24	03/31/24	15.50	04/11/24	11.00	04/17/24	6.00	32.50	335.22	10,894.65
85	Mercuria Energy America, LLC	03/01/24	03/31/24	15.50	04/11/24	11.00	04/25/24	14.00	40.50	12,639.42	511,896.51
86	Orbit Gas Transmission Inc	03/01/24	03/31/24	15.50	04/15/24	15.00	04/19/24	4.00	34.50	530.49	18,301.91
87	Symmetry Energy Solutions, LLC	03/01/24	03/31/24	15.50	04/24/24	24.00	04/25/24	1.00	40.50	86,953.60	3,521,620.80
88	Tennessee Gas Pipeline Co	03/01/24	03/31/24	15.50	04/10/24	10.00	04/22/24	12.00	37.50	372,425.27	13,965,947.63
89	Texas Gas Transmission Corporatio	03/01/24	03/31/24	15.50	04/17/24	17.00	04/19/24	2.00	34.50	1,796,056.70	61,963,956.15
90	Trunkline Gas Company, LLC	03/01/24	03/31/24	15.50	04/12/24	12.00	04/22/24	10.00	37.50	42,663.09	1,599,865.88
91	Antle Operating Company Inc.	04/01/24	04/30/24	15.00	05/15/24	15.00	05/20/24	5.00	35.00	762.03	26,671.05
92	Mercuria Energy America, LLC	04/01/24	04/30/24	15.00	05/13/24	13.00	05/28/24	15.00	43.00	10,913.32	469,272.76
93	Midwestern Gas Transmission	04/01/24	04/30/24	15.00	05/14/24	14.00	05/16/24	2.00	31.00	25,350.61	785,868.91
94	Orbit Gas Transmission Inc	04/01/24	04/30/24	15.00	05/15/24	15.00	05/16/24	1.00	31.00	3,067.15	95,081.65
95	Symmetry Energy Solutions, LLC	04/01/24	04/30/24	15.00	05/22/24	22.00	05/28/24	6.00	43.00	1,531,757.08	65,865,554.44
96	Symmetry Energy Solutions, LLC	04/01/24	04/30/24	15.00	05/22/24	22.00	05/28/24	6.00	43.00	32,387.09	1,392,644.87
97	Tennessee Gas Pipeline Co	04/01/24	04/30/24	15.00	05/10/24	10.00	05/20/24	10.00	35.00	274,736.47	9,615,776.45
98	Texas Gas Transmission Corporatio	04/01/24	04/30/24	15.00	05/09/24	9.00	05/20/24	11.00	35.00	1,596,153.90	55,865,386.50
99	Trunkline Gas Company, LLC	04/01/24	04/30/24	15.00	05/14/24	14.00	05/20/24	6.00	35.00	6,635.43	232,240.05
100	United Energy Trading, LLC	04/01/24	04/30/24	15.00	05/20/24	20.00	05/28/24	8.00	43.00	353,183.66	15,186,897.38
101	Antle Operating Company Inc.	05/01/24	05/31/24	15.50	06/13/24	13.00	06/17/24	4.00	32.50	694.32	22,565.40
102	Mercuria Energy America, LLC	05/01/24	05/31/24	15.50	06/13/24	13.00	06/25/24	12.00	40.50	13,455.61	544,952.21
103	Midwestern Gas Transmission	05/01/24	05/31/24	15.50	06/12/24	12.00	06/17/24	5.00	32.50	165.03	5,363.48
104	Orbit Gas Transmission Inc	05/01/24	05/31/24	15.50	06/13/24	13.00	06/17/24	4.00	32.50	2,694.14	87,559.55
105	Symmetry Energy Solutions, LLC	05/01/24	05/31/24	15.50	06/24/24	24.00	06/25/24	1.00	40.50	2,192,596.05	88,800,140.03

Atmos Energy Corporation-Kentucky
Per Books Purchase Gas Cost
For Base Period Ended June 30, 2024

ATO-CWC3

Line No.	Supplier	Production Month Start Service	Production Month Finish Service	Service Lag	Date of Invoice	Invoice Lag	Date Paid	Payment Lag	Total Lag	Amount	$ Days (h) x (i)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
106	Symmetry Energy Solutions, LLC	05/01/24	05/31/24	15.50	06/21/24	21.00	06/25/24	4.00	40.50	33,450.95	1,354,763.48
107	Tennessee Gas Pipeline Co	05/01/24	05/31/24	15.50	06/12/24	12.00	06/24/24	12.00	39.50	194,809.27	7,694,966.17
108	Texas Gas Transmission Corporatio	05/01/24	05/31/24	15.50	06/11/24	11.00	06/21/24	10.00	36.50	1,311,816.77	47,881,312.11
109	Trunkline Gas Company, LLC	05/01/24	05/31/24	15.50	06/12/24	12.00	06/20/24	8.00	35.50	7,181.18	254,931.89
110	United Energy Trading, LLC	05/01/24	05/31/24	15.50	06/20/24	20.00	06/28/24	8.00	43.50	230,611.62	10,031,605.47
111											
112										$ 56,193,233	$ 2,218,805,304
113											
114											39.49

To CWC1, Line 2

Atmos Energy Corporation-Kentucky ATO-CWC4
Payroll Lead Days
For Base Period Ended June 30, 2024

Line No.		Start Morning of 1st day of Pay Period	End Evening of Last Day of Pay Period	No. of Days	Service Lag	Date Paid	Payment Lag	Total Direct Payroll Lag
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		6/24/2023	07/07/23	14.00	7.00	07/14/23	7.00	14.00
2		07/08/23	07/21/23	14.00	7.00	07/28/23	7.00	14.00
3		07/22/23	08/04/23	14.00	7.00	08/11/23	7.00	14.00
4		08/05/23	08/18/23	14.00	7.00	08/25/23	7.00	14.00
5		08/19/23	09/01/23	14.00	7.00	09/08/23	7.00	14.00
6		09/02/23	09/15/23	14.00	7.00	09/22/23	7.00	14.00
7		09/16/23	09/29/23	14.00	7.00	10/06/23	7.00	14.00
8		09/30/23	10/13/23	14.00	7.00	10/20/23	7.00	14.00
9		10/14/23	10/27/23	14.00	7.00	11/03/23	7.00	14.00
10		10/28/23	11/10/23	14.00	7.00	11/17/23	7.00	14.00
11		11/11/23	11/24/23	14.00	7.00	12/01/23	7.00	14.00
12		11/25/23	12/08/23	14.00	7.00	12/15/23	7.00	14.00
13		12/09/23	12/22/23	14.00	7.00	12/29/23	7.00	14.00
14		12/23/23	01/05/24	14.00	7.00	01/12/24	7.00	14.00
15		01/06/24	01/19/24	14.00	7.00	01/26/24	7.00	14.00
16		01/20/24	02/02/24	14.00	7.00	02/09/24	7.00	14.00
17		02/03/24	02/16/24	14.00	7.00	02/23/24	7.00	14.00
18		02/17/24	03/01/24	14.00	7.00	03/08/24	7.00	14.00
19		03/02/24	03/15/24	14.00	7.00	03/22/24	7.00	14.00
20		03/16/24	03/29/24	14.00	7.00	04/05/24	7.00	14.00
21		03/30/24	04/12/24	14.00	7.00	04/19/24	7.00	14.00
22		04/13/24	04/26/24	14.00	7.00	05/03/24	7.00	14.00
23		04/27/24	05/10/24	14.00	7.00	05/17/24	7.00	14.00
24		05/11/24	05/24/24	14.00	7.00	05/31/24	7.00	14.00
25		05/25/24	06/07/24	14.00	7.00	06/14/24	7.00	14.00
26		06/08/24	06/21/24	14.00	7.00	06/28/24	7.00	14.00
27								
28								
29	TOTAL PAYROLL DIRECT DEPOSIT WEIGHTED AVG EXPENSE LAG							14.00
30								
31	ACTUAL CHECKS WRITTEN:							
32		Date				Clearing		Payroll Checks
33		Paid		# of Days		from Pd Dt		Weighted Avg
34		(e)		(h)		(i)		
35	Same day	3/8/24		0		0.00%		0.00
36	Next day	3/11/24		3		0.00%		0.00
37	2 days	3/12/24		4		28.57%		1.14
38	3-7 days	3/13/24-3/17/24		7		28.57%		2.00
39	8-14 days	3/18/24-3/24/24		14		28.57%		4.00
40	> 2 weeks	3/25/24-Present		21		14.29%		3.00
41								
42	Total Payroll Check Lag							10.14
43								
44	% of Payroll Written Checks							3.21%
45								
46	WEIGHTED AVERAGE OF ACTUAL PAYROLL CHECKS							0.33
47								
48	TOTAL PAYROLL LAG							14.33
49								
50	NOTE: Based upon pay period paid March 8 2024. Information provided by Treasury.							

ATO-CWC5

Atmos Energy Corporation-Kentucky
Other O&M Payment Lag
For Base Period Ended June 30, 2024

Line No.	Description	Weighted $ Days
	a	*b*
1	Other O&M Payment Lag Days:	23.74
2		
3		
4		
5	Total O&M Payment Lag Days:	23.74

Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For Base Period Ended June 30, 2024

CWC WP 5-1

Line No.	Vendor Name	Invoice Date	Invoice Number	Check Date	Type	Check Cleared Date	Service Period Begin	Service Period End	Service Period Midpoint	Service Lead	Payment Lead	Check Float Lead	Expense Lead	Check Amount	Division Amount	Weighting Factor (%)	Weighted Lead Days
	a	*b*	*c*	*d*	*e*	*f*	*g*	*h*	*i*	*j*	*k*	*l*	*m*	*n*	*p*	*p*	*q*
1	ACTION PEST CONTROL INC	3-Jan-24	20639275	29-Jan-24	CHECK	8-Feb-24	1-Dec-23	31-Dec-23	16-Dec-23	15.5	26	10	52	90	95	0.01%	0.01
2	ACTION PEST CONTROL INC	7-Jun-23	20624561	3-Jul-23	CHECK	11-Jul-23	1-May-23	31-May-23	16-May-23	15.5	26	8	50	85	90	0.01%	0.00
3	ACTION PEST CONTROL INC	5-Dec-23	20637428	3-Jan-24	CHECK	10-Jan-24	1-Nov-23	30-Nov-23	15-Nov-23	15	29	7	51	85	90	0.01%	0.00
4	ACTION PEST CONTROL INC	16-Apr-24	20644868	13-May-24	CHECK	21-May-24	1-Jan-24	31-Mar-24	15-Feb-24	45.5	27	8	81	45	45	0.00%	0.00
5	AIRGAS USA LLC	31-Dec-23	5504664731	25-Jan-24	ACCT	25-Jan-24	1-Dec-23	31-Dec-23	16-Dec-23	15.5	25	0	41	14,717	85	0.01%	0.00
6	AIRGAS USA LLC	10-May-24	9149776369	4-Jun-24	ACCT	4-Jun-24	10-May-24	10-May-24	10-May-24	0.5	25	0	26	449	183	0.02%	0.01
7	AIRGAS USA LLC	29-Feb-24	5506298860	25-Mar-24	CHECK	3-Apr-24	1-Feb-24	29-Feb-24	15-Feb-24	14.5	25	9	49	22,082	94	0.01%	0.00
8	AIRGAS USA LLC	30-Sep-23	5502434762	25-Oct-23	Direct Deposit	25-Oct-23	1-Sep-23	30-Sep-23	15-Sep-23	15	25	0	40	19,680	81	0.01%	0.00
9	AIRGAS USA LLC	27-Dec-23	9145368936	22-Jan-24	CHECK	30-Jan-24	27-Dec-23	27-Dec-23	27-Dec-23	0.5	26	8	35	352	92	0.01%	0.00
10	AIRGAS USA LLC	28-Mar-24	9148322882	22-Apr-24	ACCT	22-Apr-24	28-Mar-24	28-Mar-24	28-Mar-24	0.5	25	0	26	3,637	430	0.05%	0.01
11	AMERICAN WELDING AND GAS INC	30-Nov-23	9752747	27-Dec-23	CHECK	5-Jan-24	1-Nov-23	30-Nov-23	15-Nov-23	15	27	9	51	155	103	0.01%	0.01
12	APEX TITAN INC	6-May-24	43293	3-Jun-24	CHECK	11-Jun-24	30-Mar-24	26-Apr-24	12-Apr-24	14	28	8	50	1,114	1,114	0.12%	0.06
13	AT&T	1-Sep-23	1717877553 3650923-090123	13-Sep-23	CHECK	19-Sep-23	1-Aug-23	1-Sep-23	16-Aug-23	16	12	6	34	103,864	3,868	0.42%	0.14
14	AT&T MOBILITY	12-Apr-24	287295785192042 4-041224	1-May-24	CHECK	9-May-24	12-Mar-24	12-Apr-24	27-Mar-24	16	19	8	43	206,386	6,443	0.70%	0.30
15	ATMOS ENERGY CORPORATION	8-Dec-23	3005632405_20231208	11-Dec-23	Direct Deposit	11-Dec-23	18-Oct-23	15-Nov-23	1-Nov-23	14.5	3	0	18	16,984	58	0.01%	0.00
16	ATMOS ENERGY CORPORATION	8-Sep-23	3005632076_20230908	11-Sep-23	Direct Deposit	11-Sep-23	19-Jul-23	16-Aug-23	2-Aug-23	14.5	3	0	18	6,898	27	0.00%	0.00
17	ATMOS ENERGY CORPORATION	10-Jan-24	4013706168_20240110	12-Jan-24	Direct Deposit	12-Jan-24	4-Nov-23	5-Dec-23	19-Nov-23	16	2	0	18	17,825	29	0.00%	0.00
18	ATMOS ENERGY CORPORATION	10-Apr-24	4013706168_20240410	15-Apr-24	ACCT	15-Apr-24	6-Feb-24	5-Mar-24	20-Feb-24	14.5	5	0	20	29,523	39	0.00%	0.00
19	ATMOS ENERGY CORPORATION	8-Sep-23	3006775330_20230908	11-Sep-23	Direct Deposit	11-Sep-23	14-Jul-23	11-Aug-23	28-Jul-23	14.5	3	0	18	6,898	0	0.00%	0.00
20	ATMOS ENERGY CORPORATION	8-Sep-23	3009222734_20230908	11-Sep-23	Direct Deposit	11-Sep-23	7-Jul-23	3-Aug-23	20-Jul-23	14	3	0	17	6,898	4	0.00%	0.00
21	ATMOS ENERGY CORPORATION	10-Nov-23	3005632405_20231110	13-Nov-23	Direct Deposit	13-Nov-23	19-Sep-23	17-Oct-23	3-Oct-23	14.5	3	0	18	7,166	11	0.00%	0.00
22	ATMOS ENERGY CORPORATION	10-Jul-23	3005632405_20230710	12-Jul-23	Direct Deposit	12-Jul-23	17-May-23	16-Jun-23	1-Jun-23	15.5	2	0	18	7,866	12	0.00%	0.00
23	Ausenbaugh, Aaron	30-Oct-23	WEXP-00074824	7-Nov-23	Direct Deposit	7-Nov-23	26-Oct-23	26-Oct-23	26-Oct-23	0.5	8	0	9	401	401	0.04%	0.00
24	AUTOMOTIVE RENTALS INC	1-Apr-24	ARI - 01-APR-2024 - LEASE	17-Apr-24	CHECK	25-Apr-24	1-Mar-24	31-Mar-24	16-Mar-24	15.5	16	8	40	4,512,840	136,136	14.71%	5.81
25	AUTOMOTIVE RESOURCES INTERNATIONAL	10-Jul-23	ARI - 10-JUL-2023	12-Jul-23	Direct Deposit	12-Jul-23	1-Jun-23	30-Jun-23	15-Jun-23	15	2	0	17	4,114,371	266,866	28.83%	4.90
26	BAKER ELECTRIC INC	22-Mar-24	4835	17-Apr-24	CHECK	29-Apr-24	22-Mar-24	22-Mar-24	22-Mar-24	0.5	26	12	39	1,811	1,811	0.20%	0.08
27	BANK OF AMERICA	16-Jun-24	050_JEREMY.HUSS_JUN-24_PCARD	28-Jun-24	EFT	28-Jun-24	17-May-24	10-Jun-24	29-May-24	12.5	12	0	25	709,093	1,487	0.16%	0.04
28	BANK OF AMERICA	16-Apr-24	050_ROXANNE.RUBLE_APR-24_PCARD	30-Apr-24	EFT	30-Apr-24	15-Mar-24	13-Apr-24	29-Mar-24	15	14	0	29	721,438	1,332	0.14%	0.04
29	BANK OF AMERICA	16-Feb-24	050_JEREMY.HUSS_FEB-24_PCARD	29-Feb-24	EFT	29-Feb-24	18-Jan-24	15-Feb-24	1-Feb-24	14.5	13	0	28	802,704	1,621	0.18%	0.05
30	BANK OF AMERICA	16-May-24	050_MATT.HOWARD_MAY-24_PCARD	30-May-24	EFT	30-May-24	20-Apr-24	9-May-24	29-Apr-24	10	14	0	24	792,952	1,992	0.22%	0.05
31	BANK OF AMERICA	16-Sep-23	050_DANIEL.MAYFIELD_SEP-23_PCARD	29-Sep-23	EFT	29-Sep-23	25-Aug-23	30-Aug-23	27-Aug-23	3	13	0	16	614,311	963	0.10%	0.02
32	BANK OF AMERICA	16-Mar-24	050_BILL.STANLEY_MAR-24_PCARD	29-Mar-24	EFT	29-Mar-24	15-Feb-24	6-Mar-24	25-Feb-24	10.5	13	0	24	689,219	670	0.07%	0.02
33	BANK OF AMERICA	16-Sep-23	050_JIMMY.SMITH_SEP-23_PCARD	29-Sep-23	EFT	29-Sep-23	15-Aug-23	24-Aug-23	19-Aug-23	5	13	0	18	614,311	885	0.10%	0.02
34	BANK OF AMERICA	16-Jan-24	050_LANA.IGLEHEART_JAN-24_PCARD	31-Jan-24	EFT	31-Jan-24	3-Jan-24	10-Jan-24	6-Jan-24	4	15	0	19	577,784	36	0.00%	0.00
35	BANK OF AMERICA	16-Oct-23	050_DUSTIN.HARRIS_OCT-23_PCARD	1-Nov-23	EFT	1-Nov-23	18-Sep-23	3-Oct-23	25-Sep-23	8	16	0	24	621,809	24	0.00%	0.00
36	BANK OF AMERICA	16-Sep-23	050_ADRIAN.RODRIGUEZ_SEP-23_PCARD	29-Sep-23	EFT	29-Sep-23	30-Aug-23	30-Aug-23	30-Aug-23	0.5	13	0	14	614,311	191	0.02%	0.00
37	BANK OF AMERICA	16-Dec-23	050_JACOB.MOORE0_DEC-23_PCARD	29-Dec-23	EFT	29-Dec-23	13-Dec-23	13-Dec-23	13-Dec-23	0.5	13	0	14	607,406	17	0.00%	0.00
38	BANK OF AMERICA	16-Jul-23	050_DON.BONNER_JUL-23_PCARD	31-Jul-23	EFT	31-Jul-23	19-Jun-23	19-Jun-23	19-Jun-23	0.5	15	0	16	550,661	45	0.00%	0.00
39	BANK OF AMERICA	16-Jan-24	050_CHRISTOPHER.CONRAD_JAN-24_PCAR	31-Jan-24	EFT	31-Jan-24	10-Jan-24	12-Jan-24	11-Jan-24	1.5	15	0	17	577,784	104	0.01%	0.00
40	BANK OF AMERICA	16-Nov-23	050_TIM.MARTIN_NOV-23_PCARD	30-Nov-23	EFT	30-Nov-23	20-Oct-23	20-Oct-23	20-Oct-23	0.5	14	0	15	742,486	154	0.02%	0.00
41	BANK OF AMERICA	16-Feb-24	050_ANDREW.MCDOWELL_FEB-24_PCARD	29-Feb-24	EFT	29-Feb-24	13-Feb-24	13-Feb-24	13-Feb-24	0.5	13	0	14	802,704	70	0.01%	0.00
42	BANK OF AMERICA	16-Feb-24	050_PAMELA.PLEASANT_FEB-24_PCARD	29-Feb-24	EFT	29-Feb-24	18-Jan-24	15-Feb-24	1-Feb-24	14.5	13	0	28	802,704	29	0.00%	0.00
43	BANK OF AMERICA	16-Aug-23	050_MATT.PHELPS_AUG-23_PCARD	31-Aug-23	EFT	31-Aug-23	13-Aug-23	16-Aug-23	14-Aug-23	2	15	0	17	681,081	48	0.01%	0.00
44	BANK OF AMERICA	16-Aug-23	050_JAKE.BASHAM_AUG-23_PCARD	31-Aug-23	EFT	31-Aug-23	20-Jul-23	20-Jul-23	20-Jul-23	0.5	15	0	16	681,081	20	0.00%	0.00
45	BANK OF AMERICA	16-Apr-24	050_STEVEN.JOHNS_APR-24_PCARD	30-Apr-24	EFT	30-Apr-24	22-Mar-24	9-Apr-24	31-Mar-24	9.5	14	0	24	721,438	30	0.00%	0.00
46	BANK OF AMERICA	16-Jan-24	050_GAVIN.WILLIAMS_JAN-24_PCARD	31-Jan-24	EFT	31-Jan-24	20-Dec-23	20-Dec-23	20-Dec-23	0.5	15	0	16	577,784	21	0.00%	0.00
47	BANK OF AMERICA	16-Mar-24	050_FRANK.BARTLETT_MAR-24_PCARD	29-Mar-24	EFT	29-Mar-24	16-Feb-24	13-Mar-24	29-Feb-24	13.5	13	0	27	689,219	33	0.00%	0.00
48	BANK OF AMERICA	16-Feb-24	050_ED.TUCKER_FEB-24_PCARD	29-Feb-24	EFT	29-Feb-24	18-Jan-24	18-Jan-24	18-Jan-24	0.5	13	0	14	802,704	66	0.01%	0.00
49	BANK OF AMERICA	16-Feb-24	050_WALTER.MCCOLLUM_FEB-24_PCARD	29-Feb-24	EFT	29-Feb-24	27-Jan-24	6-Feb-24	1-Feb-24	5.5	13	0	19	802,704	70	0.01%	0.00
50	BANK OF AMERICA	16-Nov-23	050_CHRISTOPHER.FAULK_NOV-23_PCARD	30-Nov-23	EFT	30-Nov-23	9-Nov-23	9-Nov-23	9-Nov-23	0.5	14	0	15	742,486	36	0.00%	0.00
51	BANK OF AMERICA	16-Sep-23	050_JEFF.LAY_SEP-23_PCARD	29-Sep-23	EFT	29-Sep-23	7-Sep-23	7-Sep-23	7-Sep-23	0.5	13	0	14	614,311	96	0.01%	0.00
52	BANK OF AMERICA	16-Aug-23	050_GARY.HAMILTON_AUG-23_PCARD	31-Aug-23	EFT	31-Aug-23	16-Jul-23	27-Jul-23	21-Jul-23	6	15	0	21	681,081	27	0.00%	0.00
53	BANK OF AMERICA	16-Oct-23	050_KEVIN.MERIDETH_OCT-23_PCARD	1-Nov-23	EFT	1-Nov-23	29-Sep-23	29-Sep-23	29-Sep-23	0.5	16	0	17	621,809	78	0.01%	0.00
54	BANK OF AMERICA	16-Jun-24	050_JAMES.CRAIG_JUN-24_PCARD	28-Jun-24	EFT	28-Jun-24	5-Jun-24	10-Jun-24	7-Jun-24	3	12	0	15	709,093	83	0.01%	0.00
55	BANK OF AMERICA	16-Sep-23	050_BRANDON.GRACE_SEP-23_PCARD	29-Sep-23	EFT	29-Sep-23	22-Aug-23	29-Aug-23	25-Aug-23	4	13	0	17	614,311	106	0.01%	0.00
56	BANK OF AMERICA	16-Sep-23	050_CLAYTON.KIRBY_SEP-23_PCARD	29-Sep-23	EFT	29-Sep-23	29-Aug-23	29-Aug-23	29-Aug-23	0.5	13	0	14	614,311	89	0.01%	0.00
57	BANK OF AMERICA	16-Nov-23	050_KELLY.KEENAN_NOV-23_PCARD	30-Nov-23	EFT	30-Nov-23	14-Nov-23	15-Nov-23	14-Nov-23	1	14	0	15	742,486	106	0.01%	0.00
58	BANK OF AMERICA	16-May-24	050_DANNY.HUGHES_MAY-24_PCARD	30-May-24	EFT	30-May-24	19-Apr-24	29-Apr-24	24-Apr-24	5.5	14	0	20	792,952	176	0.02%	0.00
59	BANK OF AMERICA	16-Mar-24	050_BJ.PRICE_MAR-24_PCARD	29-Mar-24	EFT	29-Mar-24	20-Feb-24	8-Mar-24	28-Feb-24	9	13	0	22	689,219	669	0.07%	0.02
60	BANK OF AMERICA	16-Dec-23	050_JACK.SCOTT_DEC-23_PCARD	29-Dec-23	EFT	29-Dec-23	8-Dec-23	8-Dec-23	8-Dec-23	0.5	13	0	14	607,406	80	0.01%	0.00
61	BANK OF AMERICA	16-Oct-23	050_CODY.VANDIVER_OCT-23_PCARD	1-Nov-23	EFT	1-Nov-23	4-Oct-23	9-Oct-23	6-Oct-23	3	16	0	19	621,809	57	0.01%	0.00
62	BANK OF AMERICA	16-Mar-24	050_ROBERT.MURPHY_MAR-24_PCARD	29-Mar-24	EFT	29-Mar-24	22-Feb-24	28-Feb-24	25-Feb-24	3.5	13	0	17	689,219	496	0.05%	0.01
63	BANK OF AMERICA	16-Apr-24	050_WALTER.MCCOLLUM_APR-24_PCARD	30-Apr-24	EFT	30-Apr-24	17-Mar-24	15-Apr-24	31-Mar-24	15	14	0	29	721,438	288	0.03%	0.01
64	BANK OF AMERICA	16-Dec-23	050_JOSEPH.KNIGHT_DEC-23_PCARD	29-Dec-23	EFT	29-Dec-23	17-Nov-23	27-Nov-23	22-Nov-23	5.5	13	0	19	607,406	354	0.04%	0.01
65	BANK OF AMERICA	16-Apr-24	050_JAMES.DANT_APR-24_PCARD	30-Apr-24	EFT	30-Apr-24	20-Mar-24	10-Apr-24	30-Mar-24	11	14	0	25	721,438	264	0.03%	0.01
66	BANK OF AMERICA	16-Nov-23	050_CADE.WALDROP_NOV-23_PCARD	30-Nov-23	EFT	30-Nov-23	30-Oct-23	14-Nov-23	6-Nov-23	8	14	0	22	742,486	93	0.01%	0.00
67	BANK OF AMERICA	16-Nov-23	050_CHRISTOPHER.CONRAD_NOV-23_PCAR	30-Nov-23	EFT	30-Nov-23	23-Oct-23	14-Nov-23	3-Nov-23	11.5	14	0	26	742,486	245	0.03%	0.01

Exhibit JTC-4

ATO-1 Lead Lag Study

Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For Base Period Ended June 30, 2024

CWC WP 5-1

Line No.	Vendor Name	Invoice Date	Invoice Number	Check Date	Type	Check Cleared Date	Service Period Begin	Service Period End	Service Period Midpoint	Service Lead	Payment Lead	Check Float Lead	Expense Lead	Check Amount	Division Amount	Weighting Factor (%)	Weighted Lead Days
	a	*b*	*c*	*d*	*e*	*f*	*g*	*h*	*i*	*j*	*k*	*l*	*m*	*n*	*p*	*p*	*q*
68	BANK OF AMERICA	16-Aug-23	050_ROBERT.MURPHY_AUG-23_PCARD	31-Aug-23	EFT	31-Aug-23	26-Jul-23	7-Aug-23	1-Aug-23	6.5	15	0	22	681,081	291	0.03%	0.01
69	BANK OF AMERICA	16-May-24	050_BRADLEY.CORNELIUS_MAY-24_PCARD	30-May-24	EFT	30-May-24	26-Apr-24	15-May-24	5-May-24	10	14	0	24	792,952	89	0.01%	0.00
70	BANK OF AMERICA	16-Apr-24	050_BILL.STANLEY_APR-24_PCARD	30-Apr-24	EFT	30-Apr-24	5-Apr-24	12-Apr-24	8-Apr-24	4	14	0	18	721,438	914	0.10%	0.02
71	BANK OF AMERICA	16-Feb-24	050_CHRISTOPHER.CONRAD_FEB-24_PCAR	29-Feb-24	EFT	29-Feb-24	22-Jan-24	14-Feb-24	2-Feb-24	12	13	0	25	802,704	693	0.07%	0.02
72	BANK OF AMERICA	16-Feb-24	050_MATT.PHELPS_FEB-24_PCARD	29-Feb-24	EFT	29-Feb-24	17-Jan-24	7-Feb-24	27-Jan-24	11	13	0	24	802,704	242	0.03%	0.01
73	BANK OF AMERICA	16-Nov-23	050_DAMION.WHEELER_NOV-23_PCARD	30-Nov-23	EFT	30-Nov-23	17-Oct-23	9-Nov-23	28-Oct-23	12	14	0	26	742,486	527	0.06%	0.01
74	BANK OF AMERICA	16-Dec-23	050_GARY.PORTER_DEC-23_PCARD	29-Dec-23	EFT	29-Dec-23	4-Dec-23	13-Dec-23	8-Dec-23	5	13	0	18	607,406	749	0.08%	0.01
75	BANK OF AMERICA	16-Sep-23	050_MATTHEW.MCGREGOR_SEP-23_PCARI	29-Sep-23	EFT	29-Sep-23	21-Aug-23	25-Aug-23	23-Aug-23	2.5	13	0	16	614,311	66	0.01%	0.00
76	BANK OF AMERICA	16-Jan-24	050_CONNOR.BUCHANAN_JAN-24_PCARD	31-Jan-24	EFT	31-Jan-24	15-Dec-23	27-Dec-23	21-Dec-23	6.5	15	0	22	577,784	572	0.06%	0.01
77	BANK OF AMERICA	16-Jan-24	050_JACKSON.SANDERSON_JAN-24_PCARD	31-Jan-24	EFT	31-Jan-24	20-Dec-23	3-Jan-24	27-Dec-23	7.5	15	0	23	577,784	149	0.02%	0.00
78	BANK OF AMERICA	16-Jan-24	050_BRADLEY.KELTNER_JAN-24_PCARD	31-Jan-24	EFT	31-Jan-24	18-Dec-23	10-Jan-24	29-Dec-23	12	15	0	27	577,784	160	0.02%	0.00
79	BANK OF AMERICA	16-Feb-24	050_GAVIN.WILLIAMS_FEB-24_PCARD	29-Feb-24	EFT	29-Feb-24	26-Jan-24	13-Feb-24	4-Feb-24	9.5	13	0	23	802,704	145	0.02%	0.00
80	BANK OF AMERICA	16-Jul-23	050_KENNY.BASHAM_JUL-23_PCARD	31-Jul-23	EFT	31-Jul-23	28-Jun-23	12-Jul-23	5-Jul-23	7.5	15	0	23	550,661	569	0.06%	0.01
81	BANK OF AMERICA	16-Apr-24	050_ROGER.PEAK_APR-24_PCARD	30-Apr-24	EFT	30-Apr-24	15-Mar-24	10-Apr-24	28-Mar-24	13.5	14	0	28	721,438	150	0.02%	0.00
82	BANK OF AMERICA	16-Apr-24	050_FRANK.HODSKINS_APR-24_PCARD	30-Apr-24	EFT	30-Apr-24	14-Mar-24	14-Apr-24	29-Mar-24	16	14	0	30	721,438	105	0.01%	0.00
83	BANK OF AMERICA	16-May-24	050_PAUL.TOWERY_MAY-24_PCARD	30-May-24	EFT	30-May-24	13-May-24	13-May-24	13-May-24	0.5	14	0	15	792,952	208	0.02%	0.00
84	BANK OF AMERICA	16-Mar-24	050_JARED.HILL_MAR-24_PCARD	29-Mar-24	EFT	29-Mar-24	14-Mar-24	14-Mar-24	14-Mar-24	0.5	13	0	14	689,219	108	0.01%	0.00
85	BANK OF AMERICA	16-Nov-23	050_ZACHARY.BROWN_NOV-23_PCARD	30-Nov-23	EFT	30-Nov-23	27-Oct-23	15-Nov-23	5-Nov-23	10	14	0	24	742,486	169	0.02%	0.00
86	BANK OF AMERICA	16-May-24	050_NATE.YORK_MAY-24_PCARD	30-May-24	EFT	30-May-24	18-Apr-24	10-May-24	29-Apr-24	11.5	14	0	26	792,952	430	0.05%	0.01
87	BANK OF AMERICA	16-Sep-23	050_ERIC.MOHR_SEP-23_PCARD	29-Sep-23	EFT	29-Sep-23	11-Sep-23	14-Sep-23	12-Sep-23	2	13	0	15	614,311	196	0.02%	0.00
88	BANK OF AMERICA	16-Feb-24	050_LARRY.MAYES_FEB-24_PCARD	29-Feb-24	EFT	29-Feb-24	13-Feb-24	13-Feb-24	13-Feb-24	0.5	13	0	14	802,704	218	0.02%	0.00
89	BANK OF AMERICA	16-Mar-24	050_FLOYD.HONEYCUT_MAR-24_PCARD	29-Mar-24	EFT	29-Mar-24	16-Feb-24	8-Mar-24	26-Feb-24	11	13	0	24	689,219	453	0.05%	0.01
90	BANK OF AMERICA	16-Jul-23	050_ELLIOT.RIDDLE_JUL-23_PCARD	31-Jul-23	EFT	31-Jul-23	16-Jun-23	11-Jul-23	28-Jun-23	13	15	0	28	550,661	48	0.01%	0.00
91	BANK OF AMERICA	16-Jan-24	050_RANDY.HARDIN_JAN-24_PCARD	31-Jan-24	EFT	31-Jan-24	29-Dec-23	11-Jan-24	4-Jan-24	7	15	0	22	577,784	475	0.05%	0.01
92	BANK OF AMERICA	16-Nov-23	050_BRITTANY.CHATMAN_NOV-23_PCARD	30-Nov-23	EFT	30-Nov-23	17-Oct-23	9-Nov-23	28-Oct-23	12	14	0	26	742,486	1,176	0.13%	0.03
93	BANK OF AMERICA	16-Apr-24	050_JAMES.CRAIG_APR-24_PCARD	30-Apr-24	EFT	30-Apr-24	21-Mar-24	12-Apr-24	1-Apr-24	11.5	14	0	26	721,438	395	0.04%	0.01
94	BANK OF AMERICA	16-Jun-24	050_GAVIN.WILLIAMS_JUN-24_PCARD	28-Jun-24	EFT	28-Jun-24	21-May-24	6-Jun-24	29-May-24	8.5	12	0	21	709,093	438	0.05%	0.01
95	BANK OF AMERICA	16-Jul-23	050_CODY.PATE_JUL-23_PCARD	31-Jul-23	EFT	31-Jul-23	29-Jun-23	13-Jul-23	6-Jul-23	7.5	15	0	23	550,661	1,254	0.14%	0.03
96	BANK OF AMERICA	16-Feb-24	050_BILL.STANLEY_FEB-24_PCARD	29-Feb-24	EFT	29-Feb-24	16-Jan-24	10-Feb-24	28-Jan-24	13	13	0	26	802,704	1,095	0.12%	0.03
97	BANK OF AMERICA	16-May-24	050_CODY.CLARK_MAY-24_PCARD	30-May-24	EFT	30-May-24	16-Apr-24	14-May-24	30-Apr-24	14.5	14	0	29	792,952	987	0.11%	0.03
98	BANK OF AMERICA	16-Sep-23	050_RODNEY.MULLINS_SEP-23_PCARD	29-Sep-23	EFT	29-Sep-23	30-Aug-23	30-Aug-23	30-Aug-23	0.5	13	0	14	614,311	15	0.00%	0.00
99	BANK OF AMERICA	16-Nov-23	050_KENNETH.BICKETT_NOV-23_PCARD	30-Nov-23	EFT	30-Nov-23	23-Oct-23	14-Nov-23	3-Nov-23	11.5	14	0	26	742,486	337	0.04%	0.01
100	BANK OF AMERICA	16-Jul-23	050_LISA.WHITNEY_JUL-23_PCARD	31-Jul-23	EFT	31-Jul-23	16-Jun-23	7-Jul-23	26-Jun-23	11	15	0	26	550,661	937	0.10%	0.03
101	BANK OF AMERICA	16-Oct-23	050_JOSEPH.KNIGHT_OCT-23_PCARD	1-Nov-23	EFT	1-Nov-23	15-Sep-23	9-Oct-23	27-Sep-23	12.5	16	0	29	621,809	300	0.03%	0.01
102	BANK OF AMERICA	16-Dec-23	050_MIKE.LEWIS_DEC-23_PCARD	29-Dec-23	EFT	29-Dec-23	20-Nov-23	14-Dec-23	2-Dec-23	12.5	13	0	26	607,406	4,904	0.53%	0.14
103	BANK OF AMERICA	16-Aug-23	050_CHRIS.MEDLEY_AUG-23_PCARD	31-Aug-23	EFT	31-Aug-23	28-Jul-23	28-Jul-23	28-Jul-23	0.5	15	0	16	681,081	241	0.03%	0.00
104	BANK OF AMERICA	16-Jul-23	050_CHRIS.SHERFEY_JUL-23_PCARD	31-Jul-23	EFT	31-Jul-23	16-Jun-23	12-Jul-23	29-Jun-23	13.5	15	0	29	550,661	787	0.09%	0.02
105	BANK OF AMERICA	16-Apr-24	050_BRITTANY.CHATMAN_APR-24_PCARD	30-Apr-24	EFT	30-Apr-24	13-Mar-24	11-Apr-24	27-Mar-24	15	14	0	29	721,438	793	0.09%	0.02
106	BANK OF AMERICA	16-Nov-23	050_ROXANNE.RUBLE_NOV-23_PCARD	30-Nov-23	EFT	30-Nov-23	20-Oct-23	14-Nov-23	1-Nov-23	13	14	0	27	742,486	600	0.06%	0.02
107	BANK OF AMERICA	16-Sep-23	050_BRITTANY.CHATMAN_SEP-23_PCARD	29-Sep-23	EFT	29-Sep-23	18-Aug-23	11-Sep-23	30-Aug-23	12.5	13	0	26	614,311	814	0.09%	0.02
108	BANK OF AMERICA	16-Mar-24	050_PATRICK.BROWN_MAR-24_PCARD	29-Mar-24	EFT	29-Mar-24	22-Feb-24	14-Mar-24	3-Mar-24	11	13	0	24	689,219	769	0.08%	0.02
109	BANK OF AMERICA	16-Aug-23	050_ROGER.PEAK_AUG-23_PCARD	31-Aug-23	EFT	31-Aug-23	30-Jul-23	10-Aug-23	4-Aug-23	6	15	0	21	681,081	254	0.03%	0.01
110	BARRET FISHER CO INC	9-Aug-23	604085	6-Sep-23	CHECK	12-Sep-23	8-Aug-23	8-Aug-23	8-Aug-23	0.5	28	6	35	53	53	0.01%	0.00
111	BAYOU GAS ODORANTS COMPANY	14-Nov-23	24703	11-Dec-23	Direct Deposit	11-Dec-23	6-Nov-23	6-Nov-23	6-Nov-23	0.5	27	0	28	484	484	0.05%	0.01
112	BENNINGFIELD RANDY	7-Nov-23	611	4-Dec-23	Direct Deposit	4-Dec-23	7-Nov-23	7-Nov-23	7-Nov-23	0.5	27	0	28	2,368	1,084	0.12%	0.03
113	BLUE GRASS ENERGY	9-May-24	9375001_050924	9-May-24	ACCT	9-May-24	1-Apr-24	1-May-24	16-Apr-24	15.5	0	0	16	54	54	0.01%	0.00
114	BLUEGRASS NEWSMEDIA LLC	1-Jun-24	99958	5-Jun-24	CHECK	13-Jun-24	21-Jun-24	21-Jun-25	20-Dec-24	183	4	8	195	172	182	0.02%	0.04
115	BOB LILLY PROFESSIONAL PROMO	30-Aug-23	121139	25-Sep-23	Direct Deposit	25-Sep-23	18-Aug-23	18-Aug-23	18-Aug-23	0.5	26	0	27	5,335	71	0.01%	0.00
116	BOB LILLY PROFESSIONAL PROMO	9-Apr-24	126495	6-May-24	ACCT	6-May-24	14-Mar-24	26-Mar-24	20-Mar-24	6.5	27	0	34	21,331	181	0.02%	0.01
117	BOB LILLY PROFESSIONAL PROMO	13-Sep-23	129668	10-Oct-23	Direct Deposit	10-Oct-23	13-Sep-23	13-Sep-23	13-Sep-23	0.5	27	0	28	30,217	485	0.05%	0.01
118	BOB LILLY PROFESSIONAL PROMO	16-Feb-24	125210	12-Mar-24	ACCT	12-Mar-24	17-Jan-24	29-Jan-24	23-Jan-24	6.5	25	0	32	6,091	162	0.02%	0.01
119	BOB LILLY PROFESSIONAL PROMO	17-Jul-23	119532	11-Aug-23	Direct Deposit	11-Aug-23	21-Jun-23	3-Jul-23	27-Jun-23	6.5	25	0	32	5,241	680	0.07%	0.02
120	Bohlen, Silas A (Silas)	28-Aug-23	WEXP-00070728	18-Sep-23	Direct Deposit	18-Sep-23	28-Aug-23	14-Sep-23	5-Sep-23	9	21	0	30	670	670	0.07%	0.02
121	BOWLING GREEN MUNICIPAL UTILITIES	21-Dec-23	272773_122123	21-Dec-23	ACCT	21-Dec-23	1-Nov-23	5-Dec-23	18-Nov-23	17.5	0	0	18	27	27	0.00%	0.00
122	BOWLING GREEN MUNICIPAL UTILITIES	29-Apr-24	240361_042924	29-Apr-24	ACCT	29-Apr-24	14-Mar-24	16-Apr-24	30-Mar-24	17	0	0	17	27	27	0.00%	0.00
123	BOWLING GREEN MUNICIPAL UTILITIES	22-Dec-23	240361_122223	22-Dec-23	ACCT	22-Dec-23	13-Nov-23	13-Dec-23	28-Nov-23	15.5	0	0	16	26	26	0.00%	0.00
124	BRAD BROWN LAWN AND LANDSCAPE	2-Aug-23	12140	6-Sep-23	CHECK	13-Sep-23	1-Jul-23	31-Jul-23	16-Jul-23	15.5	35	7	58	350	350	0.04%	0.02
125	Brown, Zachary (Zachary)	27-Oct-23	WEXP-00074721	31-Oct-23	Direct Deposit	31-Oct-23	27-Oct-23	27-Oct-23	27-Oct-23	0.5	4	0	5	358	69	0.01%	0.00
126	CAMPBELLSVILLE WATER AND SEWER	6-Jul-23	002100145001_070623	6-Jul-23	ACCT	6-Jul-23	15-May-23	12-Jun-23	29-May-23	14.5	0	0	15	28	28	0.00%	0.00
127	CAMPBELLSVILLE WATER AND SEWER	4-Jun-24	002100145001_060424	28-Jun-24	ACCT	28-Jun-24	10-Apr-24	10-May-24	25-Apr-24	15.5	24	0	40	35	35	0.00%	0.00
128	CHAMBER OF COMMERCE	1-Mar-24	6147	20-Mar-24	CHECK	4-Apr-24	1-Jan-24	31-Dec-24	1-Jul-24	183	19	15	217	2,500	2,500	0.27%	0.59
129	CHAMBER OF COMMERCE	14-Nov-23	84105	13-Dec-23	CHECK	20-Dec-23	14-Nov-23	14-Nov-24	15-May-24	183.5	29	7	220	305	305	0.03%	0.07
130	CINTAS CORPORATION	23-Jun-23	5163924078	19-Jul-23	CHECK	25-Jul-23	23-Jun-23	23-Jun-23	23-Jun-23	0.5	26	6	33	478	25	0.00%	0.00
131	CINTAS CORPORATION	13-Feb-24	4183135543	25-Mar-24	CHECK	5-Apr-24	13-Feb-24	13-Feb-24	13-Feb-24	0.5	41	11	53	2,096	119	0.01%	0.01
132	CINTAS CORPORATION	18-Mar-24	4186628821	25-Mar-24	CHECK	5-Apr-24	18-Mar-24	18-Mar-24	18-Mar-24	0.5	7	11	19	2,096	174	0.02%	0.00
133	CINTAS CORPORATION	6-Jun-23	4157625841	6-Sep-23	CHECK	12-Sep-23	6-Jun-23	6-Jun-23	6-Jun-23	0.5	92	6	99	725	119	0.01%	0.01
134	CINTAS CORPORATION	19-Oct-23	5180584093	27-Dec-23	CHECK	3-Jan-24	19-Oct-23	19-Oct-23	19-Oct-23	0.5	69	7	77	3,724	50	0.01%	0.00

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	a	*b*	*c*	*d*	*e*	*f*	*g*	*h*	*i*	*j*	*k*	*l*	*m*	*n*	*p*	*p*	*q*
135	CITY OF DANVILLE KY	25-Jun-24	017486001_062524	25-Jun-24	ACCT	25-Jun-24	10-May-24	7-Jun-24	24-May-24	14.5	0	0	15	85	25	0.00%	0.00
136	CLARK BEVERAGE GROUP INC	24-Jan-24	6300454	31-Jan-24	CHECK	9-Feb-24	24-Jan-24	24-Jan-24	24-Jan-24	0.5	7	9	17	253	253	0.03%	0.00
137	Clark, Joseph G (Joe)	4-Jan-24	WEXP-00078415	2-Feb-24	ACCT	2-Feb-24	4-Jan-24	22-Jan-24	13-Jan-24	9.5	29	0	39	86	86	0.01%	0.00
138	Coakley, Kevin M (Kevin)	8-May-24	WEXP-00086577	14-May-24	ACCT	14-May-24	2-May-24	2-May-24	2-May-24	0.5	6	0	7	241	241	0.03%	0.00
139	Collins, Taylor	27-Feb-24	WEXP-00081787	18-Mar-24	ACCT	18-Mar-24	27-Feb-24	1-Mar-24	28-Feb-24	2	20	0	22	164	164	0.02%	0.00
140	COMCAST CABLE	23-Jan-24	8529 30 011 0059697122301-012324	31-Jan-24	CHECK	13-Feb-24	23-Dec-23	23-Jan-24	7-Jan-24	16	8	13	37	631	631	0.07%	0.03
141	COMCAST CABLE	22-Jul-23	8396 51 408 0263846062301-072223	31-Jul-23	CHECK	14-Aug-23	22-Jun-23	22-Jul-23	7-Jul-23	15.5	9	14	39	489	489	0.05%	0.02
142	COMCAST CABLE	23-Oct-23	8529 30 011 0059697092301-102323	30-Oct-23	CHECK	13-Nov-23	23-Sep-23	23-Oct-23	8-Oct-23	15.5	7	14	37	605	605	0.07%	0.02
143	COMCAST CABLE	22-Jun-24	8396 51 408 0263846052401-062224	26-Jun-24	CHECK	12-Jul-24	22-May-24	22-Jun-24	6-Jun-24	16	4	16	36	820	509	0.06%	0.02
144	CONSOLIDATED PAPER GROUP	31-Oct-23	367996	8-Nov-23	Direct Deposit	8-Nov-23	31-Oct-23	31-Oct-23	31-Oct-23	0.5	8	0	9	156	156	0.02%	0.00
145	Cooper, Joshua (Josh)	9-Oct-23	WEXP-00073592	17-Oct-23	Direct Deposit	17-Oct-23	9-Oct-23	9-Oct-23	9-Oct-23	0.5	8	0	9	513	513	0.06%	0.00
146	CORPORATE COMMUNICATIONS CENTER INC	31-Oct-23	RC231173	29-Nov-23	Direct Deposit	29-Nov-23	1-Oct-23	31-Oct-23	16-Oct-23	15.5	29	0	45	395	395	0.04%	0.02
147	CSX TRANSPORTATION INC	27-Mar-24	8461806	23-Apr-24	ACCT	23-Apr-24	11-May-24	11-May-25	9-Nov-24	183	27	0	210	52	52	0.01%	0.01
148	DAUGHERTY TRUCKING SERVICE INC	20-May-24	25704	17-Jun-24	CHECK	26-Jun-24	10-May-24	10-May-24	10-May-24	0.5	28	9	38	495	495	0.05%	0.02
149	DEERE CREDIT INC	15-Feb-24	JD Lease - 15-FEB-24	21-Feb-24	ACCT	21-Feb-24	15-Feb-24	15-Feb-24	15-Feb-24	0.5	6	0	7	241,603	28,386	3.07%	0.20
150	DEERE CREDIT INC	15-May-24	JD Lease - 15-MAY-24	20-May-24	CHECK	29-May-24	15-May-24	15-May-24	15-May-24	0.5	5	9	15	222,762	27,731	3.00%	0.43
151	Dunn, Jacob I (Jacob)	1-May-24	WEXP-00087429	24-May-24	ACCT	24-May-24	1-May-24	1-May-24	1-May-24	0.5	23	0	24	550	550	0.06%	0.01
152	EGW UTILITIES INC	7-Aug-23	1219597	1-Sep-23	Direct Deposit	1-Sep-23	4-Aug-23	4-Aug-23	4-Aug-23	0.5	25	0	26	18,910	273	0.03%	0.01
153	EGW UTILITIES INC	18-Mar-24	1236140	12-Apr-24	ACCT	12-Apr-24	12-Mar-24	12-Mar-24	12-Mar-24	0.5	25	0	26	1,546	366	0.04%	0.01
154	EGW UTILITIES INC	12-Jun-23	1215374	7-Jul-23	Direct Deposit	7-Jul-23	2-May-23	2-May-23	2-May-23	0.5	25	0	26	55,096	366	0.04%	0.01
155	ELEMENT FLEET	5-Jan-24	GE-Fleet - 05-JAN-24	10-Jan-24	Direct Deposit	10-Jan-24	1-Dec-23	31-Dec-23	16-Dec-23	15.5	5	0	21	397,169	17,844	1.93%	0.40
156	ENGLISH LUCAS PRIEST AND OWSLEY	31-Jan-24	127605	6-Mar-24	ACCT	6-Mar-24	3-Jan-24	26-Jan-24	14-Jan-24	12	35	0	47	1,559	1,559	0.17%	0.08
157	FARMERS RURAL ELECTRIC COOPERATIVE CORPORATIC	28-Nov-23	87308003_112823	28-Nov-23	ACCT	28-Nov-23	18-Oct-23	16-Nov-23	1-Nov-23	15	0	0	15	316	31	0.00%	0.00
158	Ferrell, Zachariah J (Zac)	12-Feb-24	WEXP-00081441	26-Feb-24	ACCT	26-Feb-24	12-Feb-24	12-Feb-24	12-Feb-24	0.5	14	0	15	101	101	0.01%	0.00
159	FIRST-LINE FIRE EXTINGUISHER CO	16-Aug-23	207105	11-Sep-23	CHECK	15-Sep-23	16-Aug-23	16-Aug-23	16-Aug-23	0.5	26	4	31	378	401	0.04%	0.01
160	FIRST-LINE FIRE EXTINGUISHER CO	27-Feb-24	212664	25-Mar-24	CHECK	2-Apr-24	1-Dec-23	27-Feb-24	14-Jan-24	44.5	27	8	80	716	48	0.01%	0.00
161	FP FINANCE PROGRAM	2-Oct-23	34991335	11-Oct-23	CHECK	16-Oct-23	2-Oct-23	2-Oct-23	2-Oct-23	0.5	9	5	15	127	67	0.01%	0.00
162	FP FINANCE PROGRAM	27-May-24	36689043	12-Jun-24	CHECK	21-Jun-24	3-Jun-24	3-Jun-24	3-Jun-24	0.5	16	9	26	64	67	0.01%	0.00
163	FRANKLIN ELECTRIC PLANT BOARD	6-Mar-24	204379104497_030624	6-Mar-24	ACCT	6-Mar-24	24-Jan-24	24-Feb-24	8-Feb-24	16	0	0	16	132	37	0.00%	0.00
164	FRANKLIN ELECTRIC PLANT BOARD	16-May-24	202392102472_051624	16-May-24	ACCT	16-May-24	14-Apr-24	14-May-24	29-Apr-24	15.5	0	0	16	37	37	0.00%	0.00
165	FRANKLIN ELECTRIC PLANT BOARD	5-Jun-24	204142104255_060524	6-Jun-24	ACCT	6-Jun-24	25-Apr-24	25-May-24	10-May-24	15.5	1	0	17	138	67	0.01%	0.00
166	FRANKLIN ELECTRIC PLANT BOARD	19-Jun-24	201949102017_061924	19-Jun-24	ACCT	19-Jun-24	8-May-24	8-Jun-24	23-May-24	16	0	0	16	39	39	0.00%	0.00
167	FRANKLIN ELECTRIC PLANT BOARD	20-Sep-23	203425103522_092023	20-Sep-23	ACCT	20-Sep-23	14-Aug-23	14-Sep-23	29-Aug-23	16	0	0	16	71	32	0.00%	0.00
168	GAS TECHNOLOGY INSTITUTE	18-Jul-23	246395	26-Jul-23	CHECK	31-Jul-23	19-Jun-23	23-Jun-23	21-Jun-23	2.5	8	5	16	27,410	2,149	0.23%	0.04
169	GAS TECHNOLOGY INSTITUTE	6-Sep-23	250614	11-Sep-23	CHECK	18-Sep-23	31-Jul-23	4-Aug-23	2-Aug-23	2.5	5	7	15	27,410	2,149	0.23%	0.03
170	GLASGOW ELECTRIC PLANT BOARD	22-Jan-24	207198106176_012224	22-Jan-24	ACCT	22-Jan-24	20-Dec-23	1-Jan-24	26-Dec-23	6.5	0	0	7	52	52	0.01%	0.00
171	Graham, Cody	24-Aug-23	WEXP-00070619	30-Aug-23	Direct Deposit	30-Aug-23	24-Aug-23	24-Aug-23	24-Aug-23	0.5	6	0	7	19	19	0.00%	0.00
172	HARMONS TREE SERVICE	3-Aug-23	3289	30-Aug-23	Direct Deposit	30-Aug-23	3-Aug-23	3-Aug-23	3-Aug-23	0.5	27	0	28	1,380	1,380	0.15%	0.04
173	Harrell, Joshua (Lane)	2-Feb-24	WEXP-00079983	6-Feb-24	ACCT	6-Feb-24	28-Jan-24	31-Jan-24	29-Jan-24	2	4	0	6	257	236	0.03%	0.00
174	HAWKEYE HELICOPTER LLC	11-Dec-23	32327FW	21-Dec-23	Direct Deposit	21-Dec-23	6-Dec-23	7-Dec-23	6-Dec-23	1	10	0	11	2,048	2,048	0.22%	0.02
175	HEATH CONSULTANTS INC	17-Feb-24	1140104	27-Feb-24	ACCT	27-Feb-24	17-Feb-24	17-Feb-24	17-Feb-24	0.5	10	0	11	475,617	189,691	20.49%	2.15
176	HEATH CONSULTANTS INC	15-Feb-24	1139761	26-Feb-24	ACCT	26-Feb-24	15-Feb-24	15-Feb-24	15-Feb-24	0.5	11	0	12	44,243	575	0.06%	0.01
177	Hodskins, Frank G (Frank)	11-Jul-23	WEXP-00068181	13-Jul-23	Direct Deposit	13-Jul-23	20-Jun-23	20-Jun-23	20-Jun-23	0.5	2	0	3	55	55	0.01%	0.00
178	HOPKINSVILLE ELECTRIC SYSTEM	7-May-24	216843102414_050724	7-May-24	ACCT	7-May-24	22-Mar-24	22-Apr-24	6-Apr-24	16	0	0	16	142	142	0.02%	0.00
179	HOPKINSVILLE ELECTRIC SYSTEM	19-Feb-24	202348102414_021924	19-Feb-24	ACCT	19-Feb-24	9-Jan-24	9-Feb-24	24-Jan-24	16	0	0	16	46	46	0.00%	0.00
180	HOPKINSVILLE ELECTRIC SYSTEM	9-Jan-24	204215102414_010924	10-Jan-24	ACCT	10-Jan-24	15-Nov-23	15-Dec-23	30-Nov-23	15.5	1	0	17	75	75	0.01%	0.00
181	HOPKINSVILLE ELECTRIC SYSTEM	28-Jul-23	216231062301-072823	2-Aug-23	CHECK	11-Aug-23	28-Jun-23	28-Jul-23	13-Jul-23	15.5	5	9	30	150	150	0.02%	0.00
182	HOPKINSVILLE ELECTRIC SYSTEM	28-Feb-24	2162310224-022824	28-Feb-24	CHECK	11-Mar-24	28-Jan-24	28-Feb-24	12-Feb-24	16	0	12	28	200	200	0.02%	0.01
183	Howard, Dylan (Dylan)	13-Feb-24	WEXP-00080689	20-Feb-24	ACCT	20-Feb-24	28-Jan-24	2-Feb-24	30-Jan-24	3	7	0	10	1,132	1,132	0.12%	0.01
184	Hudson, John W (John)	2-Jan-24	WEXP-00078236	8-Jan-24	Direct Deposit	8-Jan-24	27-Nov-23	27-Nov-23	27-Nov-23	0.5	6	0	7	462	462	0.05%	0.00
185	ICE MACHINES INCORPORATED	1-Apr-24	2403261115	29-Apr-24	CHECK	8-May-24	26-Mar-24	28-Mar-24	27-Mar-24	1.5	28	9	39	668	483	0.05%	0.02
186	INDUSTRIAL TRAINING SERVICES INC	8-Feb-24	22910	4-Mar-24	ACCT	4-Mar-24	7-Feb-24	7-Feb-24	7-Feb-24	0.5	25	0	26	4,494	317	0.03%	0.01
187	INFOSOURCE	1-Nov-23	44293	13-Nov-23	CHECK	20-Nov-23	1-Nov-23	1-Nov-23	1-Nov-23	0.5	12	7	20	330	330	0.04%	0.01
188	INNOVATIVE PUBLISHING	29-Jan-24	2024CI5686	26-Feb-24	CHECK	7-Mar-24	29-Jan-24	29-Jan-24	29-Jan-24	0.5	28	10	39	2,040	2,040	0.22%	0.08
189	INTER COUNTY ENERGY	9-Aug-23	11314006_080923	10-Aug-23	ACCT	10-Aug-23	1-Jul-23	1-Aug-23	16-Jul-23	16	1	0	17	85	25	0.00%	0.00
190	INTER COUNTY ENERGY	31-Oct-23	10533003_103123	31-Oct-23	ACCT	31-Oct-23	23-Sep-23	23-Oct-23	8-Oct-23	15.5	0	0	16	43	31	0.00%	0.00
191	INTER COUNTY ENERGY	29-Aug-23	10533003_082923	29-Aug-23	ACCT	29-Aug-23	23-Jul-23	22-Aug-23	7-Aug-23	15.5	0	0	16	37	25	0.00%	0.00
192	INTER COUNTY ENERGY	6-May-24	10533002_050624	6-May-24	ACCT	6-May-24	1-Apr-24	1-May-24	16-Apr-24	15.5	0	0	16	73	25	0.00%	0.00
193	INTER COUNTY ENERGY	3-Jun-24	10533002_060324	3-Jun-24	ACCT	3-Jun-24	1-May-24	1-Jun-24	16-May-24	16	0	0	16	87	26	0.00%	0.00
194	INTER COUNTY ENERGY	17-Oct-23	11314004_101723	17-Oct-23	ACCT	17-Oct-23	23-Aug-23	23-Sep-23	7-Sep-23	16	0	0	16	60	13	0.00%	0.00
195	INTER COUNTY ENERGY	31-Oct-23	11314004_103123	31-Oct-23	ACCT	31-Oct-23	23-Sep-23	23-Oct-23	8-Oct-23	15.5	0	0	16	43	13	0.00%	0.00
196	JACKSON PURCHASE ENERGY CORPORATION	21-Nov-23	700400_112123	21-Nov-23	ACCT	21-Nov-23	6-Oct-23	5-Nov-23	21-Oct-23	15.5	0	0	16	101	37	0.00%	0.00
197	JACKSON PURCHASE ENERGY CORPORATION	24-Jun-24	4393470_062424	25-Jun-24	ACCT	25-Jun-24	6-May-24	6-Jun-24	21-May-24	16	1	0	17	104	26	0.00%	0.00
198	JACKSONS LAWN CARE	28-Jun-23	2510	24-Jul-23	CHECK	31-Jul-23	28-Jun-23	28-Jun-23	28-Jun-23	0.5	26	7	34	994	337	0.04%	0.01
199	JENNINGS AND LITTLE EXCAVATING	5-Jan-24	3443	31-Jan-24	CHECK	13-Feb-24	5-Jan-24	5-Jan-24	5-Jan-24	0.5	26	13	40	18,903	1,203	0.13%	0.05
200	JH GAS STORAGE CONSULTING LLC	29-Jun-23	2023ATMOS124	24-Jul-23	Direct Deposit	24-Jul-23	2-Jan-23	13-May-23	8-Mar-23	66	25	0	91	14,073	14,073	1.52%	1.38
201	KELLYS KLEENING	29-Sep-23	1403	24-Oct-23	Direct Deposit	24-Oct-23	29-Sep-23	29-Sep-23	29-Sep-23	0.5	25	0	26	1,028	419	0.05%	0.01

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Line No.	Vendor Name	Invoice Date	Invoice Number	Check Date	Type	Check Cleared Date	Service Period Begin	Service Period End	Service Period Midpoint	Service Lead	Payment Lead	Check Float Lead	Expense Lead	Check Amount	Division Amount	Weighting Factor (%)	Weighted Lead Days
	a	*b*	*c*	*d*	*e*	*f*	*g*	*h*	*i*	*j*	*k*	*l*	*m*	*n*	*p*	*p*	*q*
202	KENERGY CORP	8-Apr-24	1740200100_040824	8-Apr-24	ACCT	8-Apr-24	2-Mar-24	2-Apr-24	17-Mar-24	16	0	0	16	415	31	0.00%	0.00
203	KENERGY CORP	25-Jan-24	2541801401_012524	25-Jan-24	ACCT	25-Jan-24	20-Dec-23	20-Jan-24	4-Jan-24	16	0	0	16	39	39	0.00%	0.00
204	KENERGY CORP	24-Jul-23	1940100300_072423	24-Jul-23	ACCT	24-Jul-23	16-Jun-23	16-Jul-23	1-Jul-23	15.5	0	0	16	211	37	0.00%	0.00
205	KENERGY CORP	11-Dec-23	1742100300_121123	11-Dec-23	ACCT	11-Dec-23	2-Nov-23	2-Dec-23	17-Nov-23	15.5	0	0	16	392	64	0.01%	0.00
206	KENERGY CORP	8-Apr-24	1731400500_040824	8-Apr-24	ACCT	8-Apr-24	2-Mar-24	2-Apr-24	17-Mar-24	16	0	0	16	415	35	0.00%	0.00
207	KENERGY CORP	26-Jun-24	0752400200_062624	26-Jun-24	ACCT	26-Jun-24	13-May-24	13-Jun-24	28-May-24	16	0	0	16	62	35	0.00%	0.00
208	KENERGY CORP	10-Aug-23	1731400500_081023	10-Aug-23	ACCT	10-Aug-23	2-Jul-23	2-Aug-23	17-Jul-23	16	0	0	16	374	35	0.00%	0.00
209	KENERGY CORP	14-May-24	1731400500_051424	14-May-24	ACCT	14-May-24	2-Apr-24	2-May-24	17-Apr-24	15.5	0	0	16	229	36	0.00%	0.00
210	KENERGY CORP	17-Jun-24	1091500800_061724	17-Jun-24	ACCT	17-Jun-24	6-May-24	6-Jun-24	21-May-24	16	0	0	16	2,661	53	0.01%	0.00
211	KENERGY CORP	11-Sep-23	1741200200_091123	11-Sep-23	ACCT	11-Sep-23	2-Aug-23	2-Sep-23	17-Aug-23	16	0	0	16	367	30	0.00%	0.00
212	KENERGY CORP	22-Dec-23	5011008600_122223	22-Dec-23	ACCT	22-Dec-23	16-Nov-23	16-Dec-23	1-Dec-23	15.5	0	0	16	57	57	0.01%	0.00
213	KENERGY CORP	10-Aug-23	1741200200_081023	10-Aug-23	ACCT	10-Aug-23	2-Jul-23	2-Aug-23	17-Jul-23	16	0	0	16	374	30	0.00%	0.00
214	KENERGY CORP	17-Nov-23	5010573100_111723	18-Nov-23	ACCT	18-Nov-23	11-Oct-23	11-Nov-23	26-Oct-23	16	1	0	17	28	28	0.00%	0.00
215	KENERGY CORP	8-Jan-24	1742100300_010824	9-Jan-24	ACCT	9-Jan-24	2-Dec-23	2-Jan-24	17-Dec-23	16	1	0	17	220	95	0.01%	0.00
216	KENERGY CORP	18-Mar-24	1691801600_031824	18-Mar-24	ACCT	18-Mar-24	6-Feb-24	6-Mar-24	20-Feb-24	15	0	0	15	1,998	25	0.00%	0.00
217	KENERGY CORP	19-Feb-24	5010573100_021924	19-Feb-24	ACCT	19-Feb-24	11-Jan-24	11-Feb-24	26-Jan-24	16	0	0	16	28	28	0.00%	0.00
218	KENERGY CORP	13-Sep-23	1691801600_091323	13-Sep-23	ACCT	13-Sep-23	6-Aug-23	6-Sep-23	21-Aug-23	16	0	0	16	275	25	0.00%	0.00
219	KENERGY CORP	24-Jul-23	4328700900_072423	24-Jul-23	ACCT	24-Jul-23	16-Jun-23	16-Jul-23	1-Jul-23	15.5	0	0	16	211	93	0.01%	0.00
220	KENERGY CORP	13-Oct-23	1091500800_101323	17-Oct-23	ACCT	17-Oct-23	6-Sep-23	6-Oct-23	21-Sep-23	15.5	4	0	20	2,242	72	0.01%	0.00
221	KGM	9-Feb-24	PSINV103832	5-Mar-24	ACCT	5-Mar-24	5-Feb-24	5-Feb-24	5-Feb-24	0.5	25	0	26	927	6,826	0.74%	0.19
222	KOORSEN FIRE AND SECURITY INC	8-Sep-23	IN00478088	11-Oct-23	CHECK	18-Oct-23	8-Sep-23	8-Sep-23	8-Sep-23	0.5	33	7	41	1,277	1,245	0.13%	0.05
223	KOORSEN FIRE AND SECURITY INC	1-Aug-23	IN00447465	28-Aug-23	Direct Deposit	28-Aug-23	1-Aug-23	31-Aug-23	16-Aug-23	15.5	27	0	43	32	32	0.00%	0.00
224	KU ENERGY CORPORATION	14-Dec-23	300000011845-300000444251_121423	15-Dec-23	ACCT	15-Dec-23	2-Oct-23	30-Oct-23	16-Oct-23	14.5	1	0	16	3,746	33	0.00%	0.00
225	KU ENERGY CORPORATION	31-Jan-24	300000011845-300001995772_013124	31-Jan-24	ACCT	31-Jan-24	27-Dec-23	27-Jan-24	11-Jan-24	16	0	0	16	4,539	43	0.00%	0.00
226	KU ENERGY CORPORATION	31-Jan-24	300000011845-300004669986_013124	31-Jan-24	ACCT	31-Jan-24	27-Dec-23	27-Jan-24	11-Jan-24	16	0	0	16	4,539	37	0.00%	0.00
227	KU ENERGY CORPORATION	31-Jan-24	300000011845-300000553275_013124	31-Jan-24	ACCT	31-Jan-24	27-Dec-23	27-Jan-24	11-Jan-24	16	0	0	16	4,539	42	0.00%	0.00
228	KU ENERGY CORPORATION	12-Feb-24	300037711334_021224	12-Feb-24	ACCT	12-Feb-24	11-Jan-24	9-Feb-24	25-Jan-24	15	0	0	15	147	50	0.01%	0.00
229	KU ENERGY CORPORATION	29-Feb-24	300034536023_022924	29-Feb-24	ACCT	29-Feb-24	30-Jan-24	28-Feb-24	13-Feb-24	15	0	0	15	155	46	0.00%	0.00
230	KU ENERGY CORPORATION	11-Apr-24	300000011845-300000621841_041124	11-Apr-24	ACCT	11-Apr-24	30-Dec-23	30-Jan-24	14-Jan-24	16	0	0	16	1,962	40	0.00%	0.00
231	KU ENERGY CORPORATION	18-Apr-24	300006773166_041824	18-Apr-24	ACCT	18-Apr-24	19-Mar-24	17-Apr-24	2-Apr-24	15	0	0	15	12	12	0.00%	0.00
232	KU ENERGY CORPORATION	15-May-24	300000011845-300003047598_051524	15-May-24	ACCT	15-May-24	19-Mar-24	19-Apr-24	3-Apr-24	16	0	0	16	4,619	47	0.01%	0.00
233	KU ENERGY CORPORATION	15-May-24	300000011845-300007037751_051524	15-May-24	ACCT	15-May-24	19-Mar-24	19-Apr-24	3-Apr-24	16	0	0	16	4,619	37	0.00%	0.00
234	KU ENERGY CORPORATION	21-Aug-23	300002064834_082123	21-Aug-23	ACCT	21-Aug-23	28-Jun-23	28-Jul-23	13-Jul-23	15.5	0	0	16	3,737	41	0.00%	0.00
235	KU ENERGY CORPORATION	15-May-24	300000011845-300007419801_051524	15-May-24	ACCT	15-May-24	19-Mar-24	19-Apr-24	3-Apr-24	16	0	0	16	4,619	41	0.00%	0.00
236	KU ENERGY CORPORATION	17-May-24	300000011845-300001916182_051724	19-May-24	ACCT	19-May-24	21-Mar-24	21-Apr-24	5-Apr-24	16	2	0	18	846	57	0.01%	0.00
237	KU ENERGY CORPORATION	17-Jul-23	300037700394_071723	17-Jul-23	ACCT	17-Jul-23	15-Jun-23	14-Jul-23	29-Jun-23	15	0	0	15	491	49	0.01%	0.00
238	KU ENERGY CORPORATION	28-May-24	300025727011_052824	28-May-24	ACCT	28-May-24	25-Apr-24	24-May-24	9-May-24	15	0	0	15	280	176	0.02%	0.00
239	KU ENERGY CORPORATION	30-May-24	300034536023_053024	30-May-24	ACCT	30-May-24	27-Apr-24	29-May-24	13-May-24	16.5	0	0	17	128	50	0.01%	0.00
240	KU ENERGY CORPORATION	11-Aug-23	300002065740_081123	12-Aug-23	ACCT	12-Aug-23	26-May-23	27-Jun-23	11-Jun-23	16.5	1	0	18	5,059	58	0.01%	0.00
241	KU ENERGY CORPORATION	21-Jun-24	300000011845-300004033944_062124	21-Jun-24	ACCT	21-Jun-24	23-May-24	28-May-24	25-May-24	3	0	0	3	4,838	81	0.01%	0.00
242	KU ENERGY CORPORATION	21-Jun-24	300000011845-300001995772_062124	21-Jun-24	ACCT	21-Jun-24	21-May-24	21-Jun-24	5-Jun-24	16	0	0	16	4,838	45	0.00%	0.00
243	KU ENERGY CORPORATION	21-Aug-23	300001542749_082123	21-Aug-23	ACCT	21-Aug-23	28-Jun-23	28-Jul-23	13-Jul-23	15.5	0	0	16	3,737	53	0.01%	0.00
244	KU ENERGY CORPORATION	22-Nov-23	300000011845-300002065740_112223	26-Nov-23	ACCT	26-Nov-23	21-Oct-23	21-Nov-23	5-Nov-23	16	4	0	20	4,653	50	0.01%	0.00
245	KU ENERGY CORPORATION	22-Nov-23	300000011845-300000550479_112223	26-Nov-23	ACCT	26-Nov-23	21-Oct-23	21-Nov-23	5-Nov-23	16	4	0	20	4,653	35	0.00%	0.00
246	KU ENERGY CORPORATION	21-Aug-23	300000550479_082123	21-Aug-23	ACCT	21-Aug-23	28-Jun-23	28-Jul-23	13-Jul-23	15.5	0	0	16	3,737	36	0.00%	0.00
247	KU ENERGY CORPORATION	20-Mar-24	300000011845-300001256431_032024	20-Mar-24	ACCT	20-Mar-24	9-Jan-24	7-Feb-24	23-Jan-24	15	0	0	15	2,131	41	0.00%	0.00
248	KU ENERGY CORPORATION	12-Dec-23	300039205657_121223	12-Dec-23	ACCT	12-Dec-23	9-Nov-23	11-Dec-23	25-Nov-23	16.5	0	0	17	52	52	0.01%	0.00
249	KU ENERGY CORPORATION	22-Nov-23	300000011845-300002064834_112223	26-Nov-23	ACCT	26-Nov-23	21-Oct-23	21-Nov-23	5-Nov-23	16	4	0	20	4,653	39	0.00%	0.00
250	KU ENERGY CORPORATION	28-Mar-24	300034536023_032824	28-Mar-24	ACCT	28-Mar-24	29-Feb-24	27-Mar-24	13-Mar-24	14	0	0	14	154	43	0.00%	0.00
251	KU ENERGY CORPORATION	10-Oct-23	300000011845-300001404759_101023	10-Oct-23	ACCT	10-Oct-23	9-Sep-23	9-Oct-23	24-Sep-23	15.5	0	0	16	4,711	39	0.00%	0.00
252	KU ENERGY CORPORATION	11-Aug-23	300001916182_081123	12-Aug-23	ACCT	12-Aug-23	26-May-23	27-Jun-23	11-Jun-23	16.5	1	0	18	5,059	62	0.01%	0.00
253	KU ENERGY CORPORATION	11-Aug-23	300001564321_081123	12-Aug-23	ACCT	12-Aug-23	26-May-23	27-Jun-23	11-Jun-23	16.5	1	0	18	5,059	194	0.02%	0.00
254	KU ENERGY CORPORATION	11-Aug-23	300004033944_081123	12-Aug-23	ACCT	12-Aug-23	26-May-23	27-Jun-23	11-Jun-23	16.5	1	0	18	5,059	80	0.01%	0.00
255	LITTLEFIELD BILLY	6-May-23	3307	16-Aug-23	CHECK	11-Sep-23	12-Mar-23	30-Apr-23	5-Apr-23	25	102	26	153	1,696	413	0.04%	0.07
256	LOCUSVIEW SOLUTIONS INC	19-Jan-24	JAN_2024	14-Feb-24	CHECK	23-Feb-24	19-Jan-24	19-Jan-24	19-Jan-24	0.5	26	9	36	188,101	426	0.05%	0.02
257	LOGANS INC	31-Jul-23	120029495	25-Aug-23	Direct Deposit	25-Aug-23	31-Jul-23	31-Jul-23	31-Jul-23	0.5	25	0	26	208	208	0.02%	0.01
258	LOGANS INC	3-Jun-24	120086873	28-Jun-24	ACCT	28-Jun-24	3-Jun-24	3-Jun-24	3-Jun-24	0.5	25	0	26	218	218	0.02%	0.01
259	LONNIE NAVE SERVICE CO	27-Dec-23	13767	22-Jan-24	CHECK	8-Feb-24	15-Dec-23	15-Dec-23	15-Dec-23	0.5	26	17	44	165	175	0.02%	0.01
260	MACO EVANSVILLE BLUE	18-Mar-24	125405	27-Mar-24	CHECK	8-Apr-24	18-Feb-24	18-Mar-24	3-Mar-24	15	9	12	36	94	94	0.01%	0.00
261	MACO EVANSVILLE BLUE	19-Jul-23	121890	26-Jul-23	CHECK	7-Aug-23	19-Jun-23	19-Jul-23	4-Jul-23	15.5	7	12	35	90	90	0.01%	0.00
262	MADISONVILLE MUNICIPAL UTILITIES	4-Oct-23	3961000_100423	4-Oct-23	ACCT	4-Oct-23	19-Aug-23	20-Sep-23	4-Sep-23	16.5	0	0	17	104	104	0.01%	0.00
263	MADISONVILLE MUNICIPAL UTILITIES	18-Dec-23	1547000_121823	18-Dec-23	ACCT	18-Dec-23	1-Nov-23	3-Dec-23	17-Nov-23	16.5	0	0	17	26	26	0.00%	0.00
264	MADISONVILLE MUNICIPAL UTILITIES	4-Mar-24	3863500_030424	4-Mar-24	ACCT	4-Mar-24	17-Jan-24	19-Feb-24	2-Feb-24	17	0	0	17	122	33	0.00%	0.00
265	MADISONVILLE MUNICIPAL UTILITIES	1-May-24	3961000_050124	1-May-24	ACCT	1-May-24	20-Mar-24	17-Apr-24	3-Apr-24	14.5	0	0	15	81	81	0.01%	0.00
266	MADISONVILLE MUNICIPAL UTILITIES	29-May-24	3961000_052924	29-May-24	ACCT	29-May-24	17-Apr-24	19-May-24	3-May-24	16.5	0	0	17	126	92	0.01%	0.00
267	MADISONVILLE MUNICIPAL UTILITIES	26-Jun-24	2331000_062624	26-Jun-24	ACCT	26-Jun-24	11-May-24	11-Jun-24	26-May-24	16	0	0	16	84	43	0.00%	0.00
268	MADISONVILLE MUNICIPAL UTILITIES	12-Jul-23	0922000_071223	12-Jul-23	ACCT	12-Jul-23	31-May-23	29-Jun-23	14-Jun-23	15	0	0	15	31	31	0.00%	0.00

Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For Base Period Ended June 30, 2024

CWC WP 5-1

Line No.	Vendor Name	Invoice Date	Invoice Number	Check Date	Type	Check Cleared Date	Service Period Begin	Service Period End	Service Period Midpoint	Service Lead	Payment Lead	Check Float Lead	Expense Lead	Check Amount	Division Amount	Weighting Factor (%)	Weighted Lead Days
	a	b	c	d	e	f	g	h	i	j	k	l	m	n	p	p	q
269	MASTERCRAFT PRINTED PRODUCTS AND SERVICES INC	8-Jun-23	123772	1-Aug-23	Direct Deposit	1-Aug-23	7-Jun-23	7-Jun-23	7-Jun-23	0.5	54	0	55	73	78	0.01%	0.00
270	MAYFIELD ELECTRIC AND WATER SYSTEMS	5-Oct-23	210021109496_100523	5-Oct-23	ACCT	5-Oct-23	19-Sep-23	30-Sep-23	24-Sep-23	6	0	0	6	66	51	0.01%	0.00
271	MAYFIELD ELECTRIC AND WATER SYSTEMS	1-Jan-24	203307103075_010124	2-Jan-24	ACCT	2-Jan-24	12-Dec-23	31-Dec-23	21-Dec-23	10	1	0	11	88	47	0.01%	0.00
272	MAYFIELD ELECTRIC AND WATER SYSTEMS	30-May-24	203307103075_053024	30-May-24	ACCT	30-May-24	12-May-24	30-May-24	21-May-24	9.5	0	0	10	151	45	0.00%	0.00
273	MAYFIELD ELECTRIC AND WATER SYSTEMS	27-Jun-24	204086100705_062724	27-Jun-24	ACCT	27-Jun-24	12-Jun-24	27-Jun-24	19-Jun-24	8	0	0	8	153	43	0.00%	0.00
274	MAYFIELD ELECTRIC AND WATER SYSTEMS	27-Mar-24	204086100705_032724	27-Mar-24	ACCT	27-Mar-24	12-Feb-24	12-Mar-24	26-Feb-24	15	0	0	15	153	43	0.00%	0.00
275	MCGEE PEST CONTROL INC	11-Dec-23	1252802	10-Jan-24	CHECK	17-Jan-24	11-Dec-23	11-Dec-23	11-Dec-23	0.5	30	7	38	99	99	0.01%	0.00
276	MCGRIFF INSURANCE SERVICES INC	8-Jan-24	5186456	14-Feb-24	CHECK	26-Feb-24	26-Feb-24	26-Feb-25	27-Aug-24	183.5	37	12	233	15,564	102	0.01%	0.03
277	MCGUIRE WOODS LLP	12-Oct-23	92763305	23-Oct-23	CHECK	2-Nov-23	1-Sep-23	30-Sep-23	15-Sep-23	15	11	10	36	30,993	2,210	0.24%	0.09
278	MEADE COUNTY RURAL ELECTRIC	14-Dec-23	110847002_121423	15-Dec-23	ACCT	15-Dec-23	3-Nov-23	3-Dec-23	18-Nov-23	15.5	1	0	17	42	42	0.00%	0.00
279	MEDIACOM	16-Dec-23	838462027009078411230l-121623	27-Dec-23	CHECK	4-Jan-24	16-Nov-23	16-Dec-23	1-Dec-23	15.5	11	8	35	476	476	0.05%	0.02
280	MILLER PEST CONTROL INC	25-Jan-24	271705	20-Feb-24	ACCT	20-Feb-24	25-Jan-24	25-Jan-24	25-Jan-24	0.5	26	0	27	25	25	0.00%	0.00
281	MILLER PEST CONTROL INC	11-Dec-23	271654	5-Jan-24	Direct Deposit	5-Jan-24	11-Dec-23	11-Dec-23	11-Dec-23	0.5	25	0	26	150	150	0.02%	0.00
282	MODERN SUPPLY COMPANY INC	28-Jan-24	224015896	5-Feb-24	CHECK	14-Feb-24	28-Jan-24	28-Jan-24	28-Jan-24	0.5	8	9	18	143	107	0.01%	0.00
283	MODERN SUPPLY COMPANY INC	27-Aug-23	223085842	6-Sep-23	CHECK	13-Sep-23	27-Aug-23	27-Aug-23	27-Aug-23	0.5	10	7	18	541	89	0.01%	0.00
284	MRC GLOBAL	9-Oct-23	MCJUNKIN - 23280KMD - 10-09-2023	30-Oct-23	Direct Deposit	30-Oct-23	2-Oct-23	9-Oct-23	5-Oct-23	4	21	0	25	4,942,828	6,249	0.68%	0.17
285	MRC GLOBAL	27-Nov-23	MCJUNKIN - 23327KMD - 11-27-2023	18-Dec-23	Direct Deposit	18-Dec-23	20-Nov-23	27-Nov-23	23-Nov-23	4	21	0	25	2,864,384	4,458	0.48%	0.12
286	MRC GLOBAL	16-Aug-23	2394469000	23-Jan-24	ACCT	23-Jan-24	15-Aug-23	15-Aug-23	15-Aug-23	0.5	160	0	161	870,749	172	0.02%	0.03
287	MUELLER COMPANY	13-May-24	65983448	28-May-24	ACCT	28-May-24	3-Apr-24	3-Apr-24	3-Apr-24	0.5	15	0	16	534	544	0.06%	0.01
288	OFFICE PRIDE CLEANING SERVICES	1-Nov-23	INV172187	5-Feb-24	CHECK	15-Feb-24	1-Nov-23	1-Nov-23	1-Nov-23	0.5	96	10	107	2,002	2,002	0.22%	0.23
289	ON TARGET CLEANING AND RESTORATION LLC	1-Apr-24	33739	29-Apr-24	CHECK	8-May-24	1-Apr-24	1-Apr-24	1-Apr-24	0.5	28	9	38	3,180	3,180	0.34%	0.13
290	ORKIN PEST CONTROL	15-May-24	1426356	29-May-24	CHECK	5-Jun-24	15-May-24	15-May-24	15-May-24	0.5	14	7	22	223	45	0.00%	0.00
291	ORKIN PEST CONTROL	12-Apr-24	1345881	29-Apr-24	CHECK	7-May-24	12-Apr-24	12-Apr-24	12-Apr-24	0.5	17	8	26	66	66	0.01%	0.00
292	OWENSBORO MUNICIPAL UTILITIES	18-Aug-23	509245100365_081823	18-Aug-23	ACCT	18-Aug-23	15-Jul-23	14-Aug-23	30-Jul-23	15.5	0	0	16	68	19	0.00%	0.00
293	OWENSBORO MUNICIPAL UTILITIES	14-Dec-23	525956100365_121423	15-Dec-23	ACCT	15-Dec-23	31-Oct-23	30-Nov-23	15-Nov-23	15.5	1	0	17	34	34	0.00%	0.00
294	OWENSBORO MUNICIPAL UTILITIES	17-Jun-24	529543100365_061724	17-Jun-24	ACCT	17-Jun-24	17-Apr-24	17-May-24	2-May-24	15.5	0	0	16	1,097	1,036	0.11%	0.02
295	P AND K PROFESSIONAL KLEAN TEAM LLC	15-May-24	4090	10-Jun-24	CHECK	20-Jun-24	15-May-24	15-May-24	15-May-24	0.5	26	10	37	2,094	2,094	0.23%	0.08
296	PADUCAH POWER SYSTEM	20-Jul-23	16603011_072023	20-Jul-23	ACCT	20-Jul-23	14-Jun-23	17-Jul-23	30-Jun-23	17	0	0	17	89	36	0.00%	0.00
297	PADUCAH POWER SYSTEM	19-Oct-23	16603017_101923	21-Oct-23	ACCT	21-Oct-23	11-Sep-23	10-Oct-23	25-Sep-23	15	2	0	17	52	52	0.01%	0.00
298	PADUCAH POWER SYSTEM	21-Nov-23	16603017_112123	21-Nov-23	ACCT	21-Nov-23	10-Oct-23	9-Nov-23	25-Oct-23	15.5	0	0	16	52	52	0.01%	0.00
299	PADUCAH POWER SYSTEM	22-Nov-23	16603021_112223	26-Nov-23	ACCT	26-Nov-23	11-Oct-23	10-Nov-23	26-Oct-23	15.5	4	0	20	95	40	0.00%	0.00
300	PADUCAH POWER SYSTEM	17-Jan-24	16603017_011724	17-Jan-24	ACCT	17-Jan-24	11-Dec-23	10-Jan-24	26-Dec-23	15.5	0	0	16	51	51	0.01%	0.00
301	PADUCAH POWER SYSTEM	6-May-24	16603004_050624	6-May-24	ACCT	6-May-24	31-Mar-24	30-Apr-24	15-Apr-24	15.5	0	0	16	902	42	0.00%	0.00
302	PADUCAH POWER SYSTEM	28-Jun-24	16603016_062824	28-Jun-24	ACCT	28-Jun-24	21-May-24	24-Jun-24	7-Jun-24	17.5	0	0	18	1,093	53	0.01%	0.00
303	Papp, Justin	12-Feb-24	WEXP-00080681	15-Feb-24	ACCT	15-Feb-24	12-Feb-24	12-Feb-24	12-Feb-24	0.5	3	0	4	12	12	0.00%	0.00
304	Papp, Justin	26-Mar-24	WEXP-00083617	1-Apr-24	ACCT	1-Apr-24	26-Mar-24	26-Mar-24	26-Mar-24	0.5	6	0	7	31	14	0.00%	0.00
305	Papp, Justin	26-Mar-24	WEXP-00083686	1-Apr-24	ACCT	1-Apr-24	26-Mar-24	26-Mar-24	26-Mar-24	0.5	6	0	7	31	17	0.00%	0.00
306	Papp, Justin	26-Apr-24	WEXP-00085674	2-May-24	ACCT	2-May-24	26-Apr-24	26-Apr-24	26-Apr-24	0.5	6	0	7	15	15	0.00%	0.00
307	Papp, Justin	11-Jan-24	WEXP-00078721	19-Jan-24	ACCT	19-Jan-24	11-Jan-24	11-Jan-24	11-Jan-24	0.5	8	0	9	19	19	0.00%	0.00
308	Papp, Justin	21-Jul-23	WEXP-00068755	31-Jul-23	Direct Deposit	31-Jul-23	21-Jul-23	21-Jul-23	21-Jul-23	0.5	10	0	11	18	18	0.00%	0.00
309	PENNYRILE RURAL ELECTRIC COOP CORP	26-Jul-23	548919010_072623	26-Jul-23	ACCT	26-Jul-23	21-Jun-23	21-Jul-23	6-Jul-23	15.5	0	0	16	644	70	0.01%	0.00
310	PENNYRILE RURAL ELECTRIC COOP CORP	28-Jul-23	548919009_072823	28-Jul-23	ACCT	28-Jul-23	19-Jun-23	19-Jul-23	4-Jul-23	15.5	0	0	16	66	32	0.00%	0.00
311	PENNYRILE RURAL ELECTRIC COOP CORP	2-Oct-23	548919016_100223	2-Oct-23	ACCT	2-Oct-23	21-Aug-23	21-Sep-23	5-Sep-23	16	0	0	16	660	42	0.00%	0.00
312	PENNYRILE RURAL ELECTRIC COOP CORP	25-Oct-23	548919011_102523	25-Oct-23	ACCT	25-Oct-23	21-Sep-23	21-Oct-23	6-Oct-23	15.5	0	0	16	633	36	0.00%	0.00
313	PENNYRILE RURAL ELECTRIC COOP CORP	30-Oct-23	548919021_103023	30-Oct-23	ACCT	30-Oct-23	26-Sep-23	26-Oct-23	11-Oct-23	15.5	0	0	16	71	37	0.00%	0.00
314	PENNYRILE RURAL ELECTRIC COOP CORP	1-Dec-23	548919006_120123	1-Dec-23	ACCT	1-Dec-23	29-Oct-23	29-Nov-23	13-Nov-23	16	0	0	16	162	46	0.00%	0.00
315	PENNYRILE RURAL ELECTRIC COOP CORP	20-Dec-23	548919014_122023	20-Dec-23	ACCT	20-Dec-23	19-Nov-23	19-Dec-23	4-Dec-23	15.5	0	0	16	84	84	0.01%	0.00
316	PENNYRILE RURAL ELECTRIC COOP CORP	22-Dec-23	548919017_122223	22-Dec-23	ACCT	22-Dec-23	21-Nov-23	21-Dec-23	6-Dec-23	15.5	0	0	16	611	49	0.01%	0.00
317	PENNYRILE RURAL ELECTRIC COOP CORP	29-Dec-23	548919021_122923	29-Dec-23	ACCT	29-Dec-23	28-Nov-23	28-Dec-23	13-Dec-23	15.5	0	0	16	71	37	0.00%	0.00
318	PENNYRILE RURAL ELECTRIC COOP CORP	12-Feb-24	548919015_021224	12-Feb-24	ACCT	12-Feb-24	31-Dec-23	31-Jan-24	15-Jan-24	16	0	0	16	73	33	0.00%	0.00
319	PENNYRILE RURAL ELECTRIC COOP CORP	29-Apr-24	548919011_042924	29-Apr-24	ACCT	29-Apr-24	20-Mar-24	20-Apr-24	4-Apr-24	16	0	0	16	655	36	0.00%	0.00
320	PENNYRILE RURAL ELECTRIC COOP CORP	28-May-24	548919014_052824	28-May-24	ACCT	28-May-24	19-Apr-24	19-May-24	4-May-24	15.5	0	0	16	158	119	0.01%	0.00
321	PENNYRILE RURAL ELECTRIC COOP CORP	3-Jun-24	548919007_060324	3-Jun-24	ACCT	3-Jun-24	27-Apr-24	26-May-24	11-May-24	15	0	0	15	161	41	0.00%	0.00
322	PERFORMANCE FOODSERVICE	22-Nov-23	660362	18-Dec-23	CHECK	26-Dec-23	23-Sep-23	23-Sep-23	23-Sep-23	0.5	26	8	35	160	170	0.02%	0.01
323	Porter, Gary R (Gary)	20-Feb-24	WEXP-00088490	11-Jun-24	ACCT	11-Jun-24	20-Feb-24	2-May-24	27-Mar-24	36.5	112	0	149	224	224	0.02%	0.04
324	POWERCLEAN JANITORIAL LLC	15-Dec-23	4258	9-Jan-24	Direct Deposit	9-Jan-24	1-Dec-23	31-Dec-23	16-Dec-23	15.5	25	0	41	245	269	0.03%	0.01
325	Price, Benjamin J. (B. J.)	11-Sep-23	WEXP-00071455	12-Sep-23	Direct Deposit	12-Sep-23	4-Aug-23	7-Sep-23	21-Aug-23	17.5	1	0	19	152	152	0.02%	0.00
326	PRINCETON EPB	1-Aug-23	202488102452_080123	1-Aug-23	ACCT	1-Aug-23	24-Jun-23	24-Jul-23	9-Jul-23	15.5	0	0	16	219	38	0.00%	0.00
327	PRINCETON EPB	1-Jan-24	201768101750_010124	2-Jan-24	ACCT	2-Jan-24	21-Nov-23	21-Dec-23	6-Dec-23	15.5	1	0	17	141	100	0.01%	0.00
328	PRINCETON EPB	28-May-24	202488102452_052824	28-May-24	ACCT	28-May-24	22-Apr-24	22-May-24	7-May-24	15.5	0	0	16	40	40	0.00%	0.00
329	PRINCETON WATER AND SEWER	27-Sep-23	003330_092723	27-Sep-23	ACCT	27-Sep-23	9-Aug-23	7-Sep-23	23-Aug-23	15	0	0	15	116	116	0.01%	0.00
330	QUALITY FENCE CO LLC KENTUCKY	11-Jan-24	23250	24-Jan-24	CHECK	13-Feb-24	5-Apr-24	5-Apr-24	5-Apr-24	0.5	13	20	34	994	1,054	0.11%	0.04
331	QUINT UTILITIES AND EXCAVATION	30-Aug-23	1257	6-Sep-23	CHECK	15-Sep-23	30-Aug-23	30-Aug-23	30-Aug-23	0.5	7	9	17	13,500	8,500	0.92%	0.15
332	REPUBLIC SERVICES	25-Jul-23	993003034793	7-Aug-23	Direct Deposit	7-Aug-23	1-Aug-23	31-Aug-23	16-Aug-23	15.5	13	0	29	240	240	0.03%	0.01
333	REPUBLIC SERVICES	25-Feb-24	993003137626	7-Mar-24	ACCT	7-Mar-24	1-Mar-24	31-Mar-24	16-Mar-24	15.5	11	0	27	3,530	244	0.03%	0.01
334	REPUBLIC SERVICES	25-Oct-23	993003077172	29-Nov-23	Direct Deposit	29-Nov-23	1-Nov-23	30-Nov-23	15-Nov-23	15	35	0	50	333	333	0.04%	0.02
335	REPUBLIC SERVICES	15-Nov-23	757001300302	27-Dec-23	Direct Deposit	27-Dec-23	1-Dec-23	31-Dec-23	16-Dec-23	15.5	42	0	58	158	158	0.02%	0.01

Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For Base Period Ended June 30, 2024

CWC WP 5-1

Line No.	Vendor Name	Invoice Date	Invoice Number	Check Date	Type	Check Cleared Date	Service Period Begin	Service Period End	Service Period Midpoint	Service Lead	Payment Lead	Check Float Lead	Expense Lead	Check Amount	Division Amount	Weighting Factor (%)	Weighted Lead Days
	a	b	c	d	e	f	g	h	i	j	k	l	m	n	p	p	q
336	REPUBLIC SERVICES	15-Jun-23	757001264471	5-Jul-23	Direct Deposit	5-Jul-23	1-Jul-23	31-Jul-23	16-Jul-23	15.5	20	0	36	125	125	0.01%	0.00
337	RICOH USA INC	31-Aug-23	CLE23080125	25-Sep-23	Direct Deposit	25-Sep-23	28-Jul-23	29-Aug-23	13-Aug-23	16.5	25	0	42	7,140	285	0.03%	0.01
338	RUSSMAR UTILITY MANAGEMENT LLC	18-Sep-23	23321	13-Oct-23	Direct Deposit	13-Oct-23	10-Oct-23	16-Oct-23	13-Oct-23	3.5	25	0	29	21,181	18,421	1.99%	0.57
339	RUSSMAR UTILITY MANAGEMENT LLC	25-Sep-23	23325	20-Oct-23	Direct Deposit	20-Oct-23	17-Sep-23	25-Sep-23	21-Sep-23	4.5	25	0	30	23,774	18,103	1.96%	0.58
340	RUSSMAR UTILITY MANAGEMENT LLC	27-May-24	24196	21-Jun-24	ACCT	21-Jun-24	19-May-24	25-May-24	22-May-24	3.5	25	0	29	20,124	10,670	1.15%	0.33
341	RUSSMAR UTILITY MANAGEMENT LLC	20-May-24	24189	14-Jun-24	ACCT	14-Jun-24	12-May-24	18-May-24	15-May-24	3.5	25	0	29	22,599	12,905	1.39%	0.40
342	Sanderson, Jackson (Jackson)	18-Aug-23	WEXP-00070212	24-Aug-23	Direct Deposit	24-Aug-23	17-Aug-23	17-Aug-23	17-Aug-23	0.5	6	0	7	83	83	0.01%	0.00
343	SCHRECKER SUPPLY COMPANY	27-Sep-23	440154	23-Oct-23	Direct Deposit	23-Oct-23	27-Sep-23	27-Sep-23	27-Sep-23	0.5	26	0	27	230	230	0.02%	0.01
344	SCOTT WASTE SERVICES INC	27-Sep-23	664846W52	11-Oct-23	CHECK	18-Oct-23	1-Sep-23	30-Sep-23	15-Sep-23	15	14	7	36	806	178	0.02%	0.01
345	SCOTT WASTE SERVICES INC	26-Apr-24	8889857W052	8-May-24	CHECK	16-May-24	1-Apr-24	30-Apr-24	15-Apr-24	15	12	8	35	1,110	370	0.04%	0.01
346	SCOTT WASTE SERVICES INC	27-Oct-23	6687028W052	15-Nov-23	CHECK	21-Nov-23	1-Oct-23	31-Oct-23	16-Oct-23	15.5	19	6	41	72	72	0.01%	0.00
347	SCOTT WASTE SERVICES INC	29-Jan-24	6787112W052	14-Feb-24	CHECK	23-Feb-24	1-Jan-24	31-Jan-24	16-Jan-24	15.5	16	9	41	841	591	0.06%	0.03
348	SCOTT WASTE SERVICES INC	27-Feb-24	6808669W052	13-Mar-24	CHECK	21-Mar-24	1-Feb-24	29-Feb-24	15-Feb-24	14.5	15	8	38	806	556	0.06%	0.02
349	SEBREE BANNER THE	2-May-24	738	20-Jun-24	CHECK	28-Jun-24	24-Apr-24	24-Apr-24	24-Apr-24	0.5	49	8	58	85	85	0.01%	0.01
350	SHELBY ENERGY COOPERATIVE INC	7-Sep-23	7095001_090723	7-Sep-23	ACCT	7-Sep-23	27-Jul-23	27-Aug-23	11-Aug-23	16	0	0	16	106	28	0.00%	0.00
351	SHELBY ENERGY COOPERATIVE INC	6-Feb-24	7095003_020624	6-Feb-24	ACCT	6-Feb-24	27-Dec-23	26-Jan-24	11-Jan-24	15.5	0	0	16	85	23	0.00%	0.00
352	SHELBYVILLE MUNICIPAL WATER AND SEWER	10-Aug-23	ATMOS_081023	10-Aug-23	ACCT	10-Aug-23	10-Apr-23	19-Apr-23	14-Apr-23	5	0	0	5	35	37	0.00%	0.00
353	SITEX CORPORATION	31-Jul-23	3074877	28-Aug-23	CHECK	5-Sep-23	3-Jul-23	31-Jul-23	17-Jul-23	14.5	28	8	51	2,328	2,328	0.25%	0.13
354	Smith, Jimmy D (Jimmy Dale)	3-Aug-23	WEXP-00069452	8-Aug-23	Direct Deposit	8-Aug-23	3-Aug-23	3-Aug-23	3-Aug-23	0.5	5	0	6	524	524	0.06%	0.00
355	SOUTH HOPKINS WATER DISTRICT	5-Mar-24	000702300001_030524	5-Mar-24	ACCT	5-Mar-24	11-Jan-24	8-Feb-24	25-Jan-24	14.5	0	0	15	77	19	0.00%	0.00
356	STANLEY PROFESSIONAL TREE SERVICE	20-Sep-23	1084	16-Oct-23	CHECK	23-Oct-23	20-Sep-23	20-Sep-23	20-Sep-23	0.5	26	7	34	21,995	21,995	2.38%	0.80
357	TAYLOR COUNTY RURAL ELECTRIC COOP CORP	13-Sep-23	26303003_091323	13-Sep-23	ACCT	13-Sep-23	31-Jul-23	31-Aug-23	15-Aug-23	16	0	0	16	404	22	0.00%	0.00
358	TAYLOR COUNTY RURAL ELECTRIC COOP CORP	13-Feb-24	26303004_021324	13-Feb-24	ACCT	13-Feb-24	31-Dec-23	31-Jan-24	15-Jan-24	16	0	0	16	275	221	0.02%	0.00
359	TAYLOR COUNTY RURAL ELECTRIC COOP CORP	13-Feb-24	26303002_021324	13-Feb-24	ACCT	13-Feb-24	31-Dec-23	31-Jan-24	15-Jan-24	16	0	0	16	275	33	0.00%	0.00
360	Taylor, Brannon C (Brannon)	14-Sep-23	WEXP-00071787	18-Sep-23	Direct Deposit	18-Sep-23	29-Aug-23	14-Sep-23	6-Sep-23	8.5	4	0	13	1,682	283	0.03%	0.00
361	TERMINIX	21-Nov-23	440538511	18-Dec-23	CHECK	26-Dec-23	21-Nov-23	21-Nov-23	21-Nov-23	0.5	27	8	36	416	157	0.02%	0.01
362	TIME WARNER CABLE	1-Oct-23	0381290011023-100123	11-Oct-23	CHECK	18-Oct-23	1-Sep-23	1-Oct-23	16-Sep-23	15.5	10	7	33	52,715	1,946	0.21%	0.07
363	Tolbert, Ryan K (Ryan)	13-Jul-23	WEXP-00068297	17-Jul-23	Direct Deposit	17-Jul-23	3-Jul-23	13-Jul-23	8-Jul-23	5.5	4	0	10	1,473	1,239	0.13%	0.01
364	Towery, Paul W (Paul)	3-Jun-24	WEXP-00088246	6-Jun-24	ACCT	6-Jun-24	3-Jun-24	3-Jun-24	3-Jun-24	0.5	3	0	4	63	63	0.01%	0.00
365	Townsend, Michael C (Cody)	22-Nov-23	WEXP-00076382	30-Nov-23	Direct Deposit	30-Nov-23	20-Nov-23	21-Nov-23	20-Nov-23	1	8	0	9	306	306	0.03%	0.00
366	Townsend, Michael C (Cody)	4-Dec-23	WEXP-00077038	19-Dec-23	Direct Deposit	19-Dec-23	19-Oct-23	13-Dec-23	15-Nov-23	28	15	0	43	575	575	0.06%	0.03
367	Townsend, Michael C (Cody)	19-Apr-24	WEXP-00085186	22-Apr-24	ACCT	22-Apr-24	16-Jan-24	19-Jan-24	17-Jan-24	2	3	0	5	531	531	0.06%	0.00
368	Tucker, Mariam L (Mariam)	1-Mar-24	WEXP-00082051	1-Apr-24	ACCT	1-Apr-24	28-Feb-24	27-Mar-24	13-Mar-24	14.5	31	0	46	404	404	0.04%	0.02
369	UTILITIES COMMISSION	3-Jan-24	101417_010324	4-Jan-24	ACCT	4-Jan-24	22-Nov-23	21-Dec-23	6-Dec-23	15	1	0	16	70	24	0.00%	0.00
370	VERIZON WIRELESS	15-Jan-24	607507434000010124-011524	31-Jan-24	CHECK	12-Feb-24	15-Dec-23	15-Jan-24	30-Dec-23	16	16	12	44	57,395	365	0.04%	0.02
371	VIKOR TELECONSTRUCTION	29-Sep-23	INV2312875	25-Oct-23	CHECK	1-Nov-23	29-Sep-23	29-Sep-23	29-Sep-23	0.5	26	7	34	7,740	3,073	0.33%	0.11
372	WARREN COUNTY WATER DISTRICT	27-Nov-23	0290390071872_112723	27-Nov-23	ACCT	27-Nov-23	22-Oct-23	22-Nov-23	6-Nov-23	16	0	0	16	293	124	0.01%	0.00
373	WARREN RURAL ELECTRIC COOP	12-Jul-23	397977016_071223	12-Jul-23	ACCT	12-Jul-23	1-Jun-23	1-Jul-23	16-Jun-23	15.5	0	0	16	53	27	0.00%	0.00
374	WARREN RURAL ELECTRIC COOP	26-Jul-23	397977013_072623	26-Jul-23	ACCT	26-Jul-23	17-Jun-23	17-Jul-23	2-Jul-23	15.5	0	0	16	70	26	0.00%	0.00
375	WARREN RURAL ELECTRIC COOP	20-Sep-23	397977008_092023	20-Sep-23	ACCT	20-Sep-23	12-Aug-23	12-Sep-23	27-Aug-23	16	0	0	16	24	24	0.00%	0.00
376	WARREN RURAL ELECTRIC COOP	25-Oct-23	397977013_102523	25-Oct-23	ACCT	25-Oct-23	17-Sep-23	17-Oct-23	2-Oct-23	15.5	0	0	16	50	26	0.00%	0.00
377	WARREN RURAL ELECTRIC COOP	25-Oct-23	397977002_102523	25-Oct-23	ACCT	25-Oct-23	17-Sep-23	17-Oct-23	2-Oct-23	15.5	0	0	16	50	24	0.00%	0.00
378	WARREN RURAL ELECTRIC COOP	8-Nov-23	397977005_110823	8-Nov-23	ACCT	8-Nov-23	29-Sep-23	29-Oct-23	14-Oct-23	15.5	0	0	16	82	27	0.00%	0.00
379	WARREN RURAL ELECTRIC COOP	11-Jan-24	397977016_011124	11-Jan-24	ACCT	11-Jan-24	1-Dec-23	1-Jan-24	16-Dec-23	16	0	0	16	28	28	0.00%	0.00
380	WARREN RURAL ELECTRIC COOP	22-Jan-24	397977017_012224	22-Jan-24	ACCT	22-Jan-24	11-Dec-23	11-Jan-24	26-Dec-23	16	0	0	16	28	28	0.00%	0.00
381	WARREN RURAL ELECTRIC COOP	25-Jan-24	397977020_012524	25-Jan-24	ACCT	25-Jan-24	14-Dec-23	14-Jan-24	29-Dec-23	16	0	0	16	61	33	0.00%	0.00
382	WARREN RURAL ELECTRIC COOP	3-Jul-23	397977012_070323	5-Jul-23	ACCT	5-Jul-23	22-May-23	22-Jun-23	6-Jun-23	16	2	0	18	84	29	0.00%	0.00
383	WEED MAN	8-Sep-23	1222332	4-Oct-23	CHECK	17-Oct-23	8-Sep-23	8-Sep-23	8-Sep-23	0.5	26	13	40	157	157	0.02%	0.01
384	WEST DAVIESS CO WATER DISTRICT	9-Oct-23	006606780000_100923	9-Oct-23	ACCT	9-Oct-23	24-Aug-23	22-Sep-23	7-Sep-23	15	0	0	15	456	2	0.00%	0.00
385	WEST KENTUCKY RURAL ELECTRIC	19-Sep-23	206330105855_091923	19-Sep-23	ACCT	19-Sep-23	13-Aug-23	13-Sep-23	28-Aug-23	16	0	0	16	48	48	0.01%	0.00
386	Westerfield, Kenneth D (Kenny)	12-Sep-23	WEXP-00071621	14-Sep-23	Direct Deposit	14-Sep-23	4-Apr-23	30-Aug-23	17-Jun-23	74.5	2	0	77	891	891	0.10%	0.07
387	WHITE FARMS EXCAVATING LLC	21-Dec-23	101	24-Jan-24	CHECK	8-Feb-24	21-Dec-23	21-Dec-23	21-Dec-23	0.5	34	15	50	400	400	0.04%	0.02
388	White, Ryne L (Ryne)	19-Mar-24	WEXP-00083186	22-Mar-24	ACCT	22-Mar-24	16-Feb-24	12-Mar-24	28-Feb-24	13	3	0	16	249	249	0.03%	0.00
389	WILLIAMS PROFESSIONAL COATINGS	18-Aug-23	14293	30-Aug-23	CHECK	6-Sep-23	18-Aug-23	18-Aug-23	18-Aug-23	0.5	12	7	20	7,950	2,500	0.27%	0.05
390	WILLIAMS PROFESSIONAL COATINGS	28-Jul-23	14290	16-Aug-23	CHECK	23-Aug-23	28-Jul-23	28-Jul-23	28-Jul-23	0.5	19	7	27	14,232	3,728	0.40%	0.11
391	WORKWEAR OUTFITTERS LLC	2-Apr-24	54395020	29-Apr-24	ACCT	29-Apr-24	28-Mar-24	28-Mar-24	28-Mar-24	0.5	27	0	28	12,025	105	0.01%	0.00
392	WORKWEAR OUTFITTERS LLC	8-Dec-23	53570165	2-Jan-24	Direct Deposit	2-Jan-24	24-Oct-23	31-Oct-23	27-Oct-23	4	25	0	29	31,376	53	0.01%	0.00
393	WORKWEAR OUTFITTERS LLC	30-Apr-24	54622412	28-May-24	ACCT	28-May-24	26-Apr-24	26-Apr-24	26-Apr-24	0.5	28	0	29	26,292	181	0.02%	0.01
394	WORKWEAR OUTFITTERS LLC	31-May-24	54883063	25-Jun-24	ACCT	25-Jun-24	30-May-24	30-May-24	30-May-24	0.5	25	0	26	33,897	43	0.00%	0.00
395	WORKWEAR OUTFITTERS LLC	13-Feb-24	54002577	11-Mar-24	ACCT	11-Mar-24	1-Feb-24	9-Feb-24	5-Feb-24	4.5	27	0	32	17,807	267	0.03%	0.01
396	WORKWEAR OUTFITTERS LLC	5-Apr-24	54430676	30-Apr-24	ACCT	30-Apr-24	3-Apr-24	3-Apr-24	3-Apr-24	0.5	25	0	26	7,987	276	0.03%	0.01
397	WORKWEAR OUTFITTERS LLC	19-Mar-24	54281447	15-Apr-24	ACCT	15-Apr-24	12-Feb-24	4-Mar-24	22-Feb-24	11	27	0	38	21,471	40	0.00%	0.00
398	WORKWEAR OUTFITTERS LLC	28-Nov-23	53477925	27-Dec-23	Direct Deposit	27-Dec-23	24-Oct-23	24-Oct-23	24-Oct-23	0.5	29	0	30	78,296	164	0.02%	0.01
399	WORKWEAR OUTFITTERS LLC	28-Nov-23	53477942	27-Dec-23	Direct Deposit	27-Dec-23	26-Oct-23	26-Oct-23	26-Oct-23	0.5	29	0	30	78,296	242	0.03%	0.01
400	WORKWEAR OUTFITTERS LLC	1-Mar-24	54154599	26-Mar-24	ACCT	26-Mar-24	29-Feb-24	29-Feb-24	29-Feb-24	0.5	25	0	26	8,741	177	0.02%	0.00
401	WORKWEAR OUTFITTERS LLC	16-Oct-23	53150998	10-Nov-23	Direct Deposit	10-Nov-23	9-Oct-23	9-Oct-23	9-Oct-23	0.5	25	0	26	19,712	242	0.03%	0.01
402	WORKWEAR OUTFITTERS LLC	15-May-24	54752571	10-Jun-24	ACCT	10-Jun-24	13-May-24	13-May-24	13-May-24	0.5	26	0	27	58,193	41	0.00%	0.00

Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For Base Period Ended June 30, 2024

CWC WP 5-1

Line No.	Vendor Name	Invoice Date	Invoice Number	Check Date	Type	Check Cleared Date	Service Period Begin	Service Period End	Service Period Midpoint	Service Lead	Payment Lead	Check Float Lead	Expense Lead	Check Amount	Division Amount	Weighting Factor (%)	Weighted Lead Days
	a	*b*	*c*	*d*	*e*	*f*	*g*	*h*	*i*	*j*	*k*	*l*	*m*	*n*	*p*	*p*	*q*
403	WORKWEAR OUTFITTERS LLC	5-Oct-23	53073984	30-Oct-23	Direct Deposit	30-Oct-23	11-Sep-23	11-Sep-23	11-Sep-23	0.5	25	0	26	31,799	81	0.01%	0.00
404	WORKWEAR OUTFITTERS LLC	11-Dec-23	53582214	5-Jan-24	Direct Deposit	5-Jan-24	26-Nov-23	26-Nov-23	26-Nov-23	0.5	25	0	26	25,397	700	0.08%	0.02
405	WORKWEAR OUTFITTERS LLC	15-Apr-24	54496112	10-May-24	ACCT	10-May-24	12-Apr-24	12-Apr-24	12-Apr-24	0.5	25	0	26	4,027	201	0.02%	0.01
406	WORKWEAR OUTFITTERS LLC	27-Feb-24	54117383	25-Mar-24	ACCT	25-Mar-24	27-Nov-23	15-Dec-23	6-Dec-23	9.5	27	0	37	22,013	60	0.01%	0.00
407	WORKWEAR OUTFITTERS LLC	6-Nov-23	53312127	1-Dec-23	Direct Deposit	1-Dec-23	31-Oct-23	31-Oct-23	31-Oct-23	0.5	25	0	26	40,052	572	0.06%	0.02
408	WORKWEAR OUTFITTERS LLC	8-May-24	54696313	3-Jun-24	ACCT	3-Jun-24	7-May-24	7-May-24	7-May-24	0.5	26	0	27	22,602	225	0.02%	0.01
409	WORKWEAR OUTFITTERS LLC	22-May-24	54815764	17-Jun-24	ACCT	17-Jun-24	20-May-24	20-May-24	20-May-24	0.5	26	0	27	52,678	54	0.01%	0.00
410	WORKWEAR OUTFITTERS LLC	28-Sep-23	53021601	23-Oct-23	Direct Deposit	23-Oct-23	27-Sep-23	27-Sep-23	27-Sep-23	0.5	25	0	26	33,632	523	0.06%	0.01
411	WORKWEAR OUTFITTERS LLC	12-Feb-24	53988597	8-Mar-24	ACCT	8-Mar-24	10-Jan-24	16-Jan-24	13-Jan-24	3.5	25	0	29	7,299	37	0.00%	0.00
412	WORKWEAR OUTFITTERS LLC	7-May-24	54686124	3-Jun-24	ACCT	3-Jun-24	7-May-24	7-May-24	7-May-24	0.5	27	0	28	22,602	460	0.05%	0.01
413	WORKWEAR OUTFITTERS LLC	18-Oct-23	53175695	5-Jan-24	Direct Deposit	5-Jan-24	9-Oct-23	9-Oct-23	9-Oct-23	0.5	79	0	80	25,397	837	0.09%	0.07
414	Totals									Total				$ 77,532,993	$ 925,589	100.00%	23.74

ATO-CWC6

Atmos Energy Corporation-Kentucky
Taxes Other Than Income Taxes
For Base Period Ended June 30, 2024

Line No.	Description	As Adjusted $ Amount	Lag Days	Weighted Lag Days
	(a)	(b)	(c)	(d)
1	**Payroll Taxes:**			
2	FICA - Paid on the day before each payday:	372,196	13.0	12.87
3				
4	Federal Unemployment - Paid quarterly in arrears at the			
5	end of the month following each quarter plus payroll service lag:	2,565	83.6	0.57
6				
7	State Unemployment - Paid quarterly in arrears at the end			
8	end of the month following each quarter plus payroll service lag:	1,057	83.6	0.24
9				
10	**Total Payroll Taxes**	375,818		13.68
11				
12	**Division Ad Valorem - Previous calendar year taxes are paid**			
13	**45 days after billed for state agencies and 30 days after**			
14	**billed for local agencies**			278.99
15				
16	**Shared Services Ad Valorem - Previous calendar year**			
17	**taxes are paid by January 31 of the current calendar year**			213.50
18				
19	**Taxes property and other**			58.82
20				
21	**Franchise and Other Pass Through Taxes**			40.37
22				
23	**Public Service Commission Assessment**			
24	**Assessment are prepaid to the Commission annually on June 26**			
25	**for 07/01 to 06/30**			(186.50)
26				
27	**DOT - Payment for the pipeline safety user fee for the**			
28	**current fiscal year is due by May 28th**			59.00

Atmos Energy Corporation-Kentucky
Federal Income Taxes
For Base Period Ended June 30, 2024

ATO-CWC7

Line No.	Due Date	Begin Test Period	End Test Period	Midpoint	Weight	Lead/Lag Days	Weighted Lead/Lag Days
	(a)	(c)	(d)	(e)	(f)	(g)	
1	**Federal Income Tax Payments:**						
2	9/15/23	7/1/2023	6/30/2024	183.00	25.00%	(107.00)	(26.75)
3	12/15/23	7/1/2023	6/30/2024	183.00	25.00%	(16.00)	(4.00)
4	4/18/24	7/1/2023	6/30/2024	183.00	25.00%	109.00	27.25
5	6/15/24	7/1/2023	6/30/2024	183.00	25.00%	167.00	41.75
6							
7					100.00%		38.25

Atmos Energy Corporation-Kentucky
State Income Taxes
For Base Period Ended June 30, 2024

ATO-CWC8

Line No.	Due Date	Begin Test Period	End Test Period	Midpoint	Weight	Lead/Lag Days	Weighted Lead/Lag Days
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**State Income Tax Payments:**						
2	September 15, 2023	7/1/2023	6/30/2024	183.00	25.00%	(107.00)	(26.75)
3	December 15, 2023	7/1/2023	6/30/2024	183.00	25.00%	(16.00)	(4.00)
4	April 18, 2024	7/1/2023	6/30/2024	183.00	25.00%	109.00	27.25
5	June 15, 2024	7/1/2023	6/30/2024	183.00	25.00%	167.00	41.75
6							
7					100.00%		38.25

ATO-CWC9

Atmos Energy Corporation-Kentucky
Long Term Debt
For Base Period Ended June 30, 2024

Atmos Energy Consolidated Balances

Line No.	Lender	Maturity	Principle	Type of Payment	Pymt 1	Pymt 2	Pymt 3	Pymt 4	Pymt 5	Pymt 6	Pymt 7	Pymt 8	Pymt 9	Pymt 10	Pymt 11	Pymt 12	Lead/Lag Days	Annual Interest	% of Total Interest	Weighted $
	(a)	(b)	(c)	(d)	(e)	(f)											(g)	(h)	(i)	(j)
1	MTN 1995-1	12/31/2025	10,000,000	SEMI ANNUAL	12/15/2023	6/15/2024											91.50	$667,000	0.20%	0.18
2	SrNote 3.00%	06/15/2027	500,000,000	SEMI ANNUAL	12/15/2023	6/15/2024											91.50	15,000,000	4.54%	4.15
3	Debentures 6.75%	07/15/28	150,000,000	SEMI ANNUAL	7/15/2023	1/15/2024											92.00	10,125,000	3.06%	2.82
4	SrNote 2.625%	9/15/2029	500,000,000	SEMI ANNUAL	9/15/2023	3/15/2024											91.00	13,125,000	3.97%	3.61
5	Sr Note 1.50%	1/15/2031	600,000,000	SEMI ANNUAL	7/15/2023	1/15/2024											92.00	9,000,000	2.72%	2.50
6	SrNote 5.45%	10/15/2032	300,000,000	SEMI ANNUAL	10/15/2023	4/15/2024											91.50	16,350,000	4.94%	4.52
7	SrNote 5.900%	11/15/2033	725,000,000	SEMI ANNUAL	11/15/2023	5/15/2024											91.00	42,775,000	12.93%	11.77
8	SrNote 5.950%	10/15/34	200,000,000	SEMI ANNUAL	10/15/2023	4/15/2024											91.50	11,900,000	3.60%	3.29
9	SrNote 5.50%	06/15/2041	400,000,000	SEMI ANNUAL	12/15/2023	6/15/2024											91.50	22,000,000	6.65%	6.09
10	SrNote 4.15%	1/15/2043	500,000,000	SEMI ANNUAL	7/15/2023	1/15/2024											92.00	20,750,000	6.27%	5.77
11	SrNote 4.125%	10/15/2044	750,000,000	SEMI ANNUAL	10/15/2023	4/15/2024											91.50	30,937,500	9.35%	8.56
12	SrNote 4.30%	10/1/2048	600,000,000	SEMI ANNUAL	10/1/2023	4/1/2024											91.50	25,800,000	7.80%	7.14
13	SrNote 4.125%	3/15/2049	450,000,000	SEMI ANNUAL	9/15/2023	3/15/2024											91.00	18,562,500	5.61%	5.11
14	SrNote 3.375%	9/15/2049	500,000,000	SEMI ANNUAL	9/15/2023	3/15/2024											91.00	16,875,000	5.10%	4.64
15	SrNote 2.85%	10/15/2052	600,000,000	SEMI ANNUAL	8/15/2023	2/15/2024											92.00	17,100,000	5.17%	4.76
16	SrNote 5.75%	10/15/2052	500,000,000	SEMI ANNUAL	10/15/2023	4/15/2024											91.50	28,750,000	8.69%	7.95
17	SrNote 6.20%	11/15/2053	500,000,000	SEMI ANNUAL	11/15/2023	5/15/2024											91.00	31,000,000	9.37%	8.53
18																				
19	WEIGHTED AVERAGE LEAD DAYS OF LONG TERM DEBT EXPENSE																	$330,717,000	100.00%	91.40

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

TESTIMONY OF EMILY B. WIEBE

INDEX TO THE DIRECT TESTIMONY
OF EMILY B. WIEBE, WITNESS FOR
ATMOS ENERGY CORPORATION

I. POSITION AND QUALIFICATIONS 1

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EXHIBIT

Exhibit EBW-1 – Cost Allocation Manual

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Emily B. Wiebe. My business address is 5430 LBJ Freeway, Suite 600, Dallas, Texas 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Accounting Services and Financial Reporting for Atmos Energy Corporation (hereinafter "Atmos Energy" or the "Company").

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. I am primarily responsible for directing various accounting and financial reporting activities and policies within the Company. My main duties include the oversight of corporate accounting, fixed assets accounting, benefits, payroll, cost allocations and internal and external financial reporting. I also serve on an internal committee that is responsible for the oversight and monitoring of Sarbanes-Oxley (SOX) compliance. In addition, I work with both our internal and external auditors on implementing, testing, maintaining, and modifying the Company's accounting controls, as well as interfacing between the auditors and the Company.

I am also responsible for overseeing effective financial and internal controls for the Company's accounting and financial reporting processes, systems, and procedures. I have knowledge of the Company's accounting and financial reporting activities, which include compiling, processing, reporting, and analyzing financial information to satisfy the requirements of internal management, internal independent auditors, external independent auditors, and regulatory agencies.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Business Administration with Distinction degree as well as a Master of Accountancy from the University of Oklahoma in 2008.

Before joining Atmos Energy, I worked in public accounting at Ernst and Young, LLP, for approximately twelve years, serving clients across multiple industries. I joined Atmos Energy in March 2021 as the Manager, Accounting Services and assumed the role of Director of Accounting Services and Financial Reporting in October 2024. In my role as both Manager, Accounting Services and Director of Accounting Services and Financial Reporting, I have worked to maintain the Company's Cost Allocation Manual ("CAM") to ensure it was aligned with Atmos Energy's recordkeeping practices.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am licensed by the State of Texas as a Certified Public Accountant ("CPA").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION OR OTHER REGULATORY ENTITIES?

A. No.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to authenticate the historical books and records of the Company and demonstrate the integrity of the financial information that has

been filed in this case. I am also providing testimony concerning the CAM, which describes the methodology for the Company's shared services cost allocations .

Q. ARE YOU SPONSORING ANY OF THE FILING REQUIREMENTS IN THIS CASE, AND, IF SO WHICH REQUIREMENTS?

A. Yes, I am sponsoring the following specific filing requirements of Section 16 of 807 K.A.R. 5:001:

FR 16(7)(i)	The most recent Federal Energy Regulatory Commission or Federal Communications Commission audit reports;
FR 16(7)(j)	The prospectuses of the most recent stock or bond offerings;
FR 16(7)(k)	Most recent FERC Form 1 (electric), FERC Form 2, or the Automated Reporting Management Information System Report (telephone) and PSC Form T (telephone);
FR 16(7)(l)	The annual report to shareholders or members and the statistical supplements covering the most recent two (2) years from the application filing date;
FR 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts chart;
FR 16(7)(n)	The latest twelve (12) months of the monthly managerial reports providing financial results of operations in comparison to the forecast;
FR 16(7)(o)	Complete monthly budget variance reports, with narrative explanations, for the twelve (12) months immediately prior

		to the base period, each month of the base period, and any subsequent months, as they become available;
	FR 16(7)(p)	A copy of the utility's annual report on Form 10-K as filed with the Securities and Exchange Commission for the most recent two (2) years, and any Form 8-K issued during the past two (2) years, and any Form 10-Q issued during the past six (6) quarters; FR 16(7)(q) Independent auditors annual opinion report, with any written communication which indicates the existence of a material weakness in internal controls; and
	FR 16(7)(q)	The independent auditor's annual opinion report, with any written communication from the independent auditor to the utility that indicates the existence of a material weakness in the utility's internal controls;
	FR 16(7)(r)	Quarterly reports to stockholders for the most recent five quarters.
	FR 16(7)(u)	Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment;
		Method and amounts allocated during base period and method and estimated amounts to be allocated during forecasted test period;

		Explain how allocator for both base and forecasted test period was determined; and
		All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable;
FR 16(8)(i)		Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for the five (5) most recent calendar years from the application filing date, the base period, the forecasted period, and two (2) calendar years beyond the forecast period;
FR 16(8)(k)		Comparative financial data and earnings measures for the ten (10) most recent calendar years, the base period, and the forecast period;

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND MAKE THEM PART OF YOUR TESTIMONY?

A. Yes.

III. AUTHENTICATION OF BOOKS AND RECORDS

Q. ARE THE BOOKS AND RECORDS OF THE COMPANY PREPARED UNDER YOUR DIRECTION?

A. Yes, for the areas under my direction (which do not include gas accounting or taxation).

Q. HOW DOES ATMOS ENERGY MAINTAIN AND UTILIZE ITS BOOKS AND RECORDS IN THE REGULAR COURSE OF BUSINESS?

A. Atmos Energy maintains its books and records in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA") and Generally Accepted Accounting Principles ("GAAP"). The USOA is the prescribed methodology for maintaining utility records in all the state jurisdictions that regulate the Company's natural gas utility operations, which currently include Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee, Texas, and Virginia.

Atmos Energy's accounting organization utilizes integrated computerized business systems to efficiently process, record, and maintain transactions generated in the regular course of business. Financial transactions are created and entered into the system at or near the time of the transaction by the responsible personnel in various divisions having personal knowledge or acting in reliance on information transmitted by persons having personal knowledge of the transactions, as well as of the applicable accounting procedures and requirements. Reports are generated by the system in the regular course of business to assist in management's review of the results of operations and to assist in the analysis of the cost data of gas operations.

Q. AS THE DIRECTOR OF ACCOUNTING SERVICES AND FINANCIAL REPORTING, HOW DO YOU ASSURE YOURSELF THAT TRANSACTIONS ARE RECORDED PROPERLY?

A. As the Director of Accounting Services and Financial Reporting, I have personal knowledge of the organizational business processes and staffing in the Controllership function. The Controller's organization is staffed with highly qualified accounting managers and staff, with many accounting positions filled by

CPAs. The managers in the organization are charged with the responsibility to inspect, review and revise, if appropriate, the work of the accountants they supervise. To fill certain management positions, an individual is required to have an accounting degree as well as significant accounting experience. We have established and maintained controls that ensure the accuracy of our books and records. These controls help identify any necessary adjustments to accounting entries which are then recorded to the original books and records in a timely manner. Additionally, Atmos Energy contracts with KPMG LLP ("KPMG") for internal audit services. This group periodically performs reviews of those controls.

Q. WHAT TYPES OF REGULAR AUDITS ARE CONDUCTED TO AUTHENTICATE ATMOS ENERGY'S BOOKS AND RECORDS?

A. Atmos Energy's books and records are audited annually by the independent public accounting firm of Ernst & Young LLP ("EY"). In addition, EY also performs reviews of Atmos Energy's quarterly financial statements. These audits and reviews are conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States).

Q. ARE THE COSTS RECORDED ON THE COMPANY'S BOOKS AND RECORDS SUPPORTED BY UNDERLYING INVOICES OR OTHER RECORDS?

A. Yes. In order for an item to be recorded in the Company's general ledger, there must be an invoice or other underlying supporting documentation. The former, for example, may be in the form of a billing invoice received from a vendor. The latter, for example, may be in the form of an employee's timesheet. The manager of a

specific cost center or project is responsible for reviewing, coding and approving invoices or other underlying supporting documentation that are charged to that particular manager's cost center or project.

Q. WHAT DO YOU MEAN BY COST CENTERS?

A. As described in the Company's CAM, a cost center is a designation generally utilized for the assignment of departmental cost responsibility and internal management reporting. Employees with responsibility for these functional areas are delegated a certain level of authority to conduct the business of the Company.

Q. HOW ARE THESE AUTHORITY LEVELS DETERMINED OR DELEGATED WITHIN THE COMPANY?

A. The Board of Directors initially delegates authority to the chief executive officer of the Company who then authorizes the Controller to further delegate authority to others throughout the Company as necessary. The Controller's approval of authority limits is generally based on a review of the needs and recommendations from those requesting authority limit changes. Approved authority limits are maintained in a secure table within the Company's accounting system.

Q. DOES THE COMPANY HAVE IN PLACE ANY PROCESS OR SYSTEM FOR THE REVIEW AND VALIDATION OF INVOICES?

A. Yes. Most invoices are scanned into an accounts payable processing system called "Markview" when they are received by the Company. Once scanned, an image of the invoice is routed electronically to the appropriate cost center owner. The cost center owner reviews and electronically codes and approves the invoice within the established approval hierarchy. As a part of this process, the cost center owner is

responsible for ensuring the cost is valid, just, and reasonable. If the amount of the invoice exceeds the authority limit of the initial approver, it is automatically escalated through the approval hierarchy to a person with the appropriate level of authority. A similar review process is performed at each level within the approval hierarchy. Once final approval has been obtained, the invoice is submitted to the accounts payable department for final payment.

Q. DOES THE COMPANY HAVE IN PLACE ANY PROCESS OR SYSTEM FOR THE REVIEW AND VALIDATION OF COSTS THAT ARE NOT PROCESSED THOUGH MARKVIEW?

A. Yes. Certain invoices and other requests for payment that are not presented as an invoice are processed outside of Markview. Examples of these types of documents include, but are not limited to, tax returns, contracts for certain outside services, or certain wire transfer requests. The process for the review, coding, and approval of these costs is the same, except that the process may be manual in nature rather than electronic. The Company employee in charge of this documentation is responsible for ensuring the cost is valid, just, and reasonable. Coding and approvals are performed within the approval hierarchy. Once final approval has been obtained, the documentation is submitted to the accounts payable department for final payment.

Q. ARE THERE ANY OTHER ACCOUNTING CONTROLS OR PROCESSES IN PLACE TO ENSURE THE ACCURACY OF THE COMPANY'S BOOKS AND RECORDS?

A. Yes. The Company executes a series of detective monitoring controls designed to identify and explain material and/or unusual costs that have been recorded in the general ledger. Occasionally, errors are found and they are typically corrected in the following month's reporting period, unless they are material. If material, these errors are corrected in the current month.

Additionally, the Chief Executive Officer and Chief Financial Officer must certify the Company's annual and quarterly financial statements and must attest to and report on the Company's system of internal control. To facilitate this effort, the Company outsources its internal audit function to KPMG to conduct tests of the Company's system of internal control. These tests are developed to ensure the system of internal control has been designed effectively and that the controls are functioning as designed as of the end of the Company's fiscal year.

Q. PLEASE DESCRIBE THE PROCESS USED TO TEST INTERNAL CONTROLS.

A. The Company maintains a SOX steering committee, which is responsible for the oversight and monitoring of SOX compliance. This committee is comprised of myself, the Vice President and Controller, the Vice President and Chief Information Officer, the Director of Gas Accounting and Rate Administration, the Director of Cybersecurity and the Director of IT Engineering and Operations.

During the first quarter of the fiscal year, the Company meets with the internal auditors to review our listing of key controls to assess whether changes to that list should be made based upon changes in the risk profile or organization of the Company. A key control is defined as a control necessary to mitigate risk and

ensure financial reporting is reasonable and materially correct. The internal audit group will develop a testing plan based upon these key controls that is reviewed and approved by the SOX steering committee. The key controls are tested throughout the year. If issues arise, they are individually addressed by a steering committee member who has knowledge of the affected areas. The SOX steering committee meets regularly to assess the progress and review the results of the testing. During this process, all findings are discussed and the steering committee will determine whether the finding should be considered a control deficiency, a significant deficiency, or a material weakness. A control deficiency exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent or detect misstatements on a timely basis. A significant deficiency is a deficiency, or a combination of deficiencies, in internal control over financial reporting that is less severe than a material weakness, yet important enough to merit attention by those responsible for oversight of the Company's financial reporting. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis.

At the end of the fiscal year, the steering committee makes recommendations regarding the effectiveness of the Company’s internal control structure to be included in the internal auditor’s final report to the audit committee.

Q. PLEASE SUMMARIZE THE RESULTS OF TESTING FOR THE MOST RECENTLY COMPLETED FISCAL YEAR.

A. The most recent fiscal year for which results are available is fiscal year 2023. During fiscal year 2023, a total of 315 key controls related to the Company's operations were tested and 26 control deficiencies and one significant deficiency were identified. As of September 30, 2023, the significant deficiency and 21 of the control deficiencies had been remediated. Of the remaining 5 un-remediated controls, 4 have subsequently been remediated in fiscal year 2024. The remaining un-remediated control has not had any control instances within fiscal year 2024. It will be retested when the next control instance occurs.

Q. ARE THESE CONTROL DEFICIENCIES THE SAME DEFICIENCIES THAT WERE IDENTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO.2021-00214?

A. No. The deficiencies identified in fiscal 2023 are not the same deficiencies identified before the Kentucky Public Service Commission in Case No. 2021-00214.

Q. ARE THE COMPANY'S TESTS OF INTERNAL CONTROL SUBJECT TO EXAMINATION BY AN INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM?

A. Yes. As a publicly traded company, Atmos Energy is required to have an independent registered public accounting firm audit our management's public assertions regarding the Company's system of internal control. EY serves as the Company's independent registered public accounting firm.

Q. CAN YOU SUMMARIZE THE PROCESS USED BY EY TO PERFORM ITS ATTEST FUNCTION?

A. Yes. EY will perform independent tests regarding the design of the Company's internal control function and the effectiveness of the controls as of the end of the fiscal year. They will rely, in part, on the work performed by the internal auditors in completing their audit procedures. Upon completion of their work, EY will issue an audit report summarizing their findings, which is included in the Company's annual report on Form 10-K.

Q. DID EY'S MOST RECENT REPORT DIFFER FROM THE FINDINGS OF MANAGEMENT?

A. No. EY issued an unqualified audit report for fiscal 2023, which means that they agreed with management's assertions.

Q. ARE THERE OTHER TYPES OF REGULAR AUDITS AND REVIEWS THAT ARE CONDUCTED OF ATMOS ENERGY'S BOOKS AND RECORDS?

A. Yes. In addition to the audit of internal control, EY also conducts an annual audit of Atmos Energy's books and records. In addition, EY performs reviews of Atmos Energy's quarterly financial statements. These audits and reviews are conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States).

Q. HOW DOES THE ACCOUNTING SYSTEM PERMIT THE SEPARATE RECORDING AND TRACKING OF COSTS FOR ATMOS ENERGY'S UTILITY DIVISIONS?

A. Direct costs are charged directly to the natural gas distribution division that has incurred the costs. In addition, technical and support services are provided to the distribution divisions by centralized shared services departments primarily located at the Atmos Energy headquarters in Dallas. These centralized functions include, but are not limited to, accounting, human resources, legal, treasury, risk management, etc. The costs for these shared services are allocated to the operating divisions.

Q. WERE THE BOOKS AND RECORDS OF THE COMPANY PROVIDED TO THE COMPANY WITNESSES FOR UTILIZATION IN THEIR ANALYSIS FOR RATEMAKING PURPOSES?

A. Yes.

IV. COST ALLOCATION MANUAL

Q. WHAT IS THE COST ALLOCATION MANUAL?

A. The CAM, contained in Exhibit EBW-1, describes and documents the process whereby allocations are made within the books and records of the Company. These include allocations of various common expenses that are incurred for the benefit of two or more of the Company's rate divisions and are therefore allocable to those rate divisions. Additionally, the CAM also describes and documents the processes whereby allocations are made between Atmos Energy and its affiliates and between affiliates.

Q. PLEASE DESCRIBE THE HISTORY OF THE CAM.

A. Although the Company had been utilizing the allocation methodology described in the CAM for many years prior, the CAM was formally documented in response to

807 K.A.R. 5:080, and was first filed with the Commission in April of 2001. Atmos Energy is required to update the CAM each year. The Company has used the CAM to document its allocation processes in the regular course of business since it was first filed.

Q. ARE THE ALLOCATIONS DESCRIBED IN THE CAM USED IN EVERY JURISDICTION IN WHICH ATMOS ENERGY OPERATES?

A. Yes. The CAM is uniformly applied in all eight states in which Atmos Energy has regulated utility operations for the allocation of common costs among Atmos Energy's various operating divisions, including Kentucky.

Q. DOES THE CAM DESCRIBE HOW TO ALLOCATE BALANCE SHEET AMOUNTS?

A. No. The CAM describes how to allocate expense items from Atmos Energy's income statement. Investment or balance sheet items are not allocated within Atmos Energy's books and records. Investment amounts are allocated only for ratemaking purposes in the context of a rate filing or certain regulatory reports.

Q. IN YOUR OPINION, DOES THE COMPANY'S ALLOCATION PROCESS UNIFORMLY AND CONSISTENTLY ALLOCATE COMMON OR SHARED SERVICES COSTS?

A. Yes, the allocation process described in the CAM operates fairly and reasonably in allocating those costs on a uniform basis, both as between Atmos Energy's various operating divisions and affiliates and between the various regulatory jurisdictions in which the Company operates.

V. PROPOSAL FOR ACCOUNTING CHANGE FOR CLOUD COMPUTING

Q. PLEASE DESCRIBE CLOUD COMPUTING AND THE COMPANY'S REQUEST IN THIS CASE.

A. Cloud computing is the delivery of Information Technology ("IT") products, including servers, storage, databases, networking and software, over the internet or "cloud." The Company does not take possession of the software or hardware because it is owned, hosted, and maintained by a third-party provider. To use the capabilities of these products, the Company pays an annual fee for the use of the software, the hosting services and necessary maintenance. Examples of Atmos Energy's cloud computing implementations and subscriptions include digital construction management, supplier management, data analytics, leak survey data management, emergency callout systems, productivity support, business continuity services, customer billing and relationship management, human resources management, collaboration services, budgeting and planning, ticket management solutions, and regulatory reporting, accounting, and audit support.

Q. DOES THE COMPANY PROPOSE CHANGES TO THE ACCOUNTING FOR CLOUD COMPUTING IN THIS FILING?

A. Yes, the Company is requesting authorization from the Commission to account for cloud computing software in a manner more consistent with how these same types of hardware and software were accounted for when the Company purchased the hardware and software rather than obtain it through cloud computing contracts. These programs are essential for the Company's ability to provide safe and reliable

service to customers. The Company proposes to capitalize all cloud computing costs with contract terms greater than one year in FERC account 399.08.

Q. ARE CLOUD COMPUTING COSTS ELIGIBLE FOR CAPITALIZATION?

A. Yes. The Company's existing cloud computing arrangements ("CCAs") are for software as a service ("SAS") and infrastructure as a service ("IFS"), and these services may be capitalized after evaluation under specific accounting guidance. For both SAS and IFS, it must be demonstrated that control of the software exists, which can take various forms.

For SAS type CCAs, if the arrangement includes an identifiable cost associated with a license, then that cost may be eligible to be capitalized. However, it must also be demonstrated that 1) a contractual right to take possession of the software at any time may occur without significant penalty or loss in functionality; and 2) it is feasible to run the software on the Company's own hardware or contract with another party to do so. This can be difficult as not all CCAs include the detail to reasonably make that determination. If the determination cannot be made, no costs would be capitalized despite the long-term benefit to the Company.

For IFS, the ability to restrict or dictate the way in which the CCA provider may utilize the underlying infrastructure would demonstrate control, for example a dedicated server reserved for the service recipient alone.

Additionally, certain CCAs costs such as implementation and development costs may be eligible to be capitalized for both SAS and IFS.

Q. DOES THE COMPANY CURRENTLY CAPITALIZE ANY CLOUD COMPUTING COSTS?

A. Yes. The Company currently defers implementation costs for SAS arrangements as described below. However, the Company does not currently capitalize any ongoing costs related to SAS or IFS arrangements.

Q. DOES THE COMPANY'S PROPOSED CHANGE IMPACT HOW CLOUD COMPUTING COSTS ARE INCLUDED IN THIS FILING?

A. Yes. The Company is proposing adjustments to rate base and O&M related to cloud computing in this filing for implementation costs.

Q. PLEASE DESCRIBE THE NEW RATE BASE AND O&M RELATED ADJUSTMENTS FOR CLOUD COMPUTING INCLUDED IN THIS FILING.

A. As mentioned in the Direct Testimony of Company witness Gregory K. Waller, an adjustment was made to forecasted plant in service to include the per book balances at June 30, 2024 of the allocated implementation costs for cloud computing projects. These expenditures related to the implementation costs incurred for current SAS arrangements are recorded to FERC Accounts 186 Miscellaneous Deferred Debits, 182.3 Other Regulatory Assets and 174 Miscellaneous Current and Accrued Assets. These costs do not include any agreements with terms of one (1) year or less; additionally, the total spend for the application software is greater than $50,000. Any item under $50,000 has been expensed. The Company's proposed adjustment reflects the June 30th account balances of 186, 182.3 and 174 added as an adjustment to plant account 399.08 in SSU Divisions general office and customer support. This would allow those costs to be recovered in the current filing in rate base.

Q. HAS THIS ACCOUNTING TREATMENT BEEN APPROVED BY A COMMISSION ACROSS ATMOS ENERGY'S EIGHT STATES FOR USE BY OTHER LDCs?

A. Yes. The Railroad Commission of Texas ("RCT") has authorized Texas Gas Service to capitalize its cloud computing costs and recover these amounts in future annual capital tracker filings.[1] The RCT similarly concluded that, with the exception of contracts having terms of one year or less, it was reasonable to allow CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas Energy Entex ("CenterPoint") to capitalize 100% of its cloud computing costs to FERC account 186 and recover those costs in its annual capital tracker filings.[2] The adjustment and the capitalization of these costs in this filing is consistent with CenterPoint's approved treatment in RCT Docket No. OS-23-00015513. Atmos Energy plans to include analogous adjustments in the upcoming general rate case filings in its two Texas distribution divisions.

The Company proposes that the depreciation rate for plant account 399.08 be based upon the rate proposed by Mr. Allis in this proceeding.

Company witness Gregory K. Waller discusses the Company's proposed O&M adjustment to remove the allocated O&M expense, as depreciation expense will be calculated on the adjusted plant balance for accounts 399.08.

[1] *See* GUD No. 10928 consol., FoF No. 70 (Aug. 4, 2020); Docket OS-22-00009896, consolidated, *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area,* Final Order at FoF Nos. 51 and 52 (Jan. 18, 2023). TGS ultimately records these costs to gas plant account 391.99 - Cloud Computing

[2] *See e.g.* Docket OS-23-00015513, consolidated, Final Order at FoF No. 50 (June 25, 2024).

Q. DOES THE COMPANY PROPOSE CHANGES TO HOW CLOUD COMPUTING IMPLEMENTATION COSTS ARE HANDLED BY THE COMPANY IN FUTURE PERIODS?

A. Yes. The Company proposes that immediately following the test period in this case (April 1, 2026) all cloud computing implementation costs currently recorded in accounts 174, 186, and 182.3 for software as a service arrangement be recorded to plant account 399.08 and that all future costs be recorded directly to plant account 399.08.

Q. IS THE COMPANY PROPOSING ANY RATE BASE AND O&M RELATED ADJUSTMENTS FOR ONGOING THIRD-PARTY COSTS FOR CCAS IN FUTURE PERIODS?

A. Yes. Ongoing third-party costs for CCAs are currently recorded in prepayments (FERC account 165) and are amortized over the life of the arrangement to expense. In this filing, the Company proposes no changes to the CCAs recorded in the test year to prepayments account 165 or to the O&M accounts where amortization is recorded. However, subsequent to the test year (April 1, 2026), upon approval in this proceeding, the Company proposes to record these new amounts directly to plant account 399.08 and discontinue the recording of amortization expense on new amounts in O&M. These amounts recorded to plant account 399.08 would have depreciation expense calculated as described above.

In summary, upon approval in this proceeding, all new unamortized ongoing and future cloud computing costs incurred for third party CCAs with a contract term greater than one year would be recorded directly to plant account 399.08 and

the depreciation rate be based upon the rate approved in this proceeding for plant account 399.08.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Emily B. Wiebe, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Emily B. Wiebe

STATE OF TEXAS

COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Emily B. Wiebe on this the 23rd day of September, 2024.

Notary Public

My Commission Expires: September 1, 2024

Giselle R Heroy
My Commission Expires
9/1/2028
Notary ID130804842

ATMOS ENERGY CORPORATION
COST ALLOCATION MANUAL
April 1, 2024

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1. Introduction:

a. Corporate Structure

Atmos Energy Corporation (Atmos Energy or the Company) operates its Regulated Operations through seven (7) operating divisions in eight (8) states. The seven operating divisions and their service areas are:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas
Atmos Energy Kentucky/Mid-States Division	Kentucky, Tennessee, Virginia
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas
Atmos Pipeline – Texas Division	Intrastate pipeline business in Texas

These operating divisions are not subsidiaries or separate legal entities. Therefore, by definition, they cannot be considered affiliates of Atmos Energy.

Technical and support services are provided to the operating divisions by centralized shared services departments primarily located at the Atmos Energy headquarters in Dallas. These centralized functions currently include, but are not limited to, accounting, gas supply, human resources, information technology, legal, rates and customer support. The costs for these shared services are allocated to the operating divisions. In addition, for operating divisions that operate in more than one rate jurisdiction, costs are first allocated to the general office and then to the separate rate divisions accordingly within the operating division.

Atmos Energy Holdings, Inc. is a wholly owned subsidiary of Atmos Energy Corporation. Atmos Energy Holdings and its various wholly owned subsidiaries are separate legal entities and are considered affiliates of Atmos Energy.

The Company’s current legal entity organization chart is contained in Appendix A.

Note that the descriptions contained herein do not address tariffed services.

b. Accounting:

Atmos Energy’s account coding structure enables it to capture the costs for allocable activities. Expenses, assets, and liabilities for Atmos Energy's shared services and other operating division general office divisions are coded to applicable location codes and cost centers as necessary and are then allocated to the appropriate rate divisions based upon the methodologies described herein. Allocations recorded in the books and records of the Company are primarily for management control purposes and may not reflect the allocation methodology used for rate making purposes.

Atmos Energy's account coding structure is as follows:

XXX.	XXXX.	XXXX.	XXXXX.	XXXXXX.	XXXX
Company 3 digits	Cost Center 4 digits	FERC Account 4 digits	Sub-Account 5 digits	Service Area 6 digits	Future Use 4 digits

Within the above coding structure "Company" and "Cost Center" are primarily utilized for internal management responsibility reporting purposes for Atmos Energy's operating divisions. The terms "Company" and "Cost Center" are defined in the glossary beginning below. Utilization of the "Company" or "Cost Center" fields is not suitable for meaningful financial or regulatory reporting purposes.

The FERC account field contains the three-digit FERC USOA account plus one extension digit which in some cases is utilized by the FERC USOA.

The first three digits of the Service Area field are the primary coding utilized for cost allocations within Atmos Energy and is generally referred to as "rate division number". This portion of the field denotes Atmos Energy's various rate divisions as well as the Company's various shared services and operating division general office divisions. These codes are the primary source of information for regulatory reporting and rate activity. The remaining three digits represent "town" location which is utilized only for some accounts. Atmos Pipeline-Texas ("APT") uses the final three digits of the service area to represent the actual storage or compressor facility; however, this is used for O&M expenses only.

c. Glossary of Terms:

The following terms are defined for purposes of this document only:

Affiliate – One or more of Atmos Energy's subsidiaries.

Below the Line - Amounts which are generally not included in an analysis of costs from which gas service rates are derived.

Company - In general terms, it refers to Atmos Energy Corporation. Within the context of the account coding string, this term represents an operating division, wholly owned subsidiary or other legal entity controlled by Atmos Energy.

Composite Factor - The Company's general allocation factor which is based upon the simple average of gross plant in service, average number of customers and direct operation and maintenance expenses for each applicable operating division and service area, as applicable.

For divisions with general office service areas, allocations from these general offices to specific rate divisions also use the composite rate for each applicable rate division. Variations of this composite factor are further defined below in more detail. The composite factor is reviewed annually for any items outside of the ordinary course of business to determine if identified items should be excluded from the calculation. Any one-time exclusions will be documented and approved by the VP & Controller.

This composite factor is unique for each operating division/service area; however, the formula base for each use of the composite factor is the same.

(1) The percentage of Gross Utility and Non-Utility Property Plant and Equipment in each specific applicable division unit as a percentage of the total Direct Property Plant and Equipment in all of the applicable divisions.

(2) The average number of customers from the prior fiscal year in each specific applicable division unit as a percentage of the total number of customers in all of the applicable divisions.

(3) The total direct O&M expense in each specific applicable division unit as a percentage of the total direct O&M expense in all applicable divisions.

Corporate Headquarters - The headquarters of Atmos Energy Corporation is located in Dallas, Texas.

Cost Center - Account coding which denotes an area of cost responsibility. This coding is used primarily for management purposes.

Customer Factor – Allocation that is based on customer factors only and used as necessary when the allocation should only be based on customers. It is derived based on the average number of customers in the Operating Divisions that receive allocable costs for the services provided.

Direct Charges – Charges that originate in a shared services department, operating division general office division, or rate division that are recorded directly to the applicable rate division.

FERC USOA - The Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission.

Municipal Jurisdiction -. A Texas legal construct wherein each municipality (i.e., incorporated cities, towns, and villages) served by Atmos Energy has original jurisdiction over rates.

Operating Division - An unincorporated division of Atmos Energy Corporation that contains at least one rate division that is responsible for the management of the Company's Regulated Operations. Operating divisions are not subsidiaries or separate legal entities. As such, they do not have separate equity or debt structures. Additionally, the divisions do not keep separate books and records. Operating divisions with multiple rate divisions have one general office rate division in addition to rate divisions corresponding to regulatory jurisdictional areas.

Operating Division General Office - Administrative offices that are located outside of shared service offices which serve as the base of operations and central office for each operating division that serves multiple rate divisions “.

Rate Division – Often referred to as an operating rate division, it denotes Atmos Energy's regulatory jurisdictions that are defined by state and geographic boundaries. The term also denotes Atmos Energy's various shared services and operating division general office divisions. These divisions are the primary source for regulatory reporting and rate activity for an area in which rates have been set by a regulatory authority such as the Colorado Public Utilities Commission. Rate divisions are identifiable in the Company's account coding string. As such, costs are accumulated within the general ledger and represent the sum of direct costs plus costs allocated to the rate division.

Regulated Operations – Represents the Company's six regulated natural gas distribution operating divisions operating in eight states and the Company's regulated intrastate pipeline operations in the State of Texas.

Service Area - The portion of the Company's account coding structure of which the first three digits denote rate division. The last three digits of this code denote "town" which is used only in certain instances. Atmos Pipeline-Texas uses the final three digits of the service area to represent the actual storage or compressor facility; however, this is used for O&M expenses only.

Shared Services - The Company's functions that serve multiple rate divisions. These services include departments such as legal, billing, call center, accounting, information technology, human resources, gas supply, rates administration, among others. Shared Service costs are tracked in two service areas: Shared Services – General Office (Service Area 002) and Shared Services – Customer Support (Service Area 012).

Shared Services – Customer Support – Shared Services functions that include customer billing, customer call center functions and customer support related services.

Shared Services – General Office – Shared Services functions that include all other functions not encompassed by Shared Services – Customer Support.

The following are the operating divisions of Atmos Energy Corporation:

Atmos Energy Colorado-Kansas Division is a regulated operating division that serves approximately 170 communities throughout Colorado and Kansas, including the cities of Olathe, Kansas, a suburb of Kansas City and Greeley, Colorado, located near Denver.

Atmos Energy Kentucky/Mid-States Division is a regulated operating division that operates Kentucky, Tennessee, and Virginia. The service areas in these states are primarily rural; however, this division serves Franklin, Tennessee, and other suburban areas of Nashville.

Atmos Energy Louisiana Division is a regulated operating division that serves nearly 300 communities, including the suburban areas of New Orleans, the metropolitan area of Monroe and western Louisiana. Direct sales of natural gas to industrial customers in Louisiana, who use gas for fuel or in manufacturing processes, and sales of natural gas for vehicle fuel are exempt from regulation and are recognized in our Atmos Energy Louisiana Industrial Gas segment.

Atmos Energy Mid-Tex Division is a regulated operating division that serves approximately 550 incorporated and unincorporated communities in the north-central, eastern, and western parts of Texas, including the Dallas/Fort Worth Metroplex. The governing body of each municipality served by Atmos Energy has original jurisdiction over all gas distribution rates, operations, and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. The Railroad Commission of Texas (RRC) has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality.

Atmos Energy Mississippi Division is a regulated operating division that serves about 110 communities throughout the northern half of the state, including the Jackson metropolitan area.

Atmos Energy West Texas Division is a regulated operating division that serves approximately 80 communities in West Texas, including the Amarillo, Lubbock, and Midland/Odessa areas. Like our Mid-Tex Division, each municipality we serve has original jurisdiction over all gas distribution rates, operations, and services within its city limits, with the RRC having exclusive appellate jurisdiction over the municipalities and exclusive original jurisdiction over rates and services provided to customers not located within the limits of a municipality.

Atmos Pipeline – Texas Division is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas producing areas of central, northern, and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. APT provides transportation and storage services to our Mid-Tex Division, other third-party local distribution companies, industrial and electric generation customers, as well as marketers and producers. As part of its pipeline operations, APT manages five underground storage reservoirs in Texas.

The following are affiliates of Atmos Energy Corporation:

Blueflame Insurance Services, LTD is a wholly owned subsidiary of Atmos Energy Corporation that was created to provide cost-effective property insurance coverage for Atmos Energy and its subsidiaries. It was chartered in Bermuda effective December 16, 2003, and became operational as of January 1, 2004. It is incorporated under Bermuda's insurance law and regulations and is fully capitalized under the requirements of applicable Bermuda law.

Atmos Energy Kansas Securitization I, LLC ("AEK") is a wholly-owned special purpose limited liability company subsidiary of Atmos Energy Corporation that was established on October 28, 2022 for the sole purpose to issue securitized utility tariff bonds and the right to impose and collect securitized utility tariff charges paid by all existing and future retail customers within Atmos Energy's service area in Kansas related to the recovery of costs in relation to Winter Storm Uri. The issuance of the utility tariff bonds occurred in June 2023 in the amount of $95 million with a term of 10 years. AEK is considered to be a variable interest entity that is consolidated within Atmos Energy Corporation.

Atmos Energy Services, LLC ("AES") was established on April 1, 2004, to provide natural gas management services to Atmos Energy's natural gas distribution operations, other than the Mid-Tex Division. These services include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to Atmos Energy's natural gas distribution service areas at competitive prices. AES provided these services through December 31, 2006. Effective January 1, 2007, the gas supply department within shared services began providing these services.

Phoenix Gas Gathering Company is a wholly owned subsidiary of Atmos Gathering Company, LLC, and was created to develop, own, and operate a non-regulated natural gas gathering system located in Kentucky.

Atmos Gathering Company, LLC is a wholly owned subsidiary of Atmos Pipeline and Storage, LLC and was created to conduct our non-regulated natural gas gathering operations.

Atmos Energy Holdings, Inc. is the parent company of Atmos Energy Corporation's non-utility operations.

Atmos Energy Louisiana Industrial Gas, LLC serves industrial customers in Louisiana who use gas for fuel, manufacturing, and other processes.

Atmos Exploration and Production, Inc. holds some insignificant Kentucky production interests which the Company succeeded to when it acquired Western Kentucky Gas Company in 1987. This subsidiary is functionally inactive as the Company does not actively engage in the exploration and production business.

Atmos Pipeline and Storage, LLC owns or has an interest in underground storage fields in Kentucky and Louisiana. The utility divisions of Atmos Energy also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Atmos Power Systems, Inc. constructs gas-fired electric peaking power generating plant and associated facilities and may enter into agreements to either lease or sell these plants. Since 2001, 2 sales-type lease transactions have been executed.

Egasco, LLC was, several years ago, engaged in the marketing and sale of natural gas to large-volume commercial and agricultural customers in West Texas. Egasco no longer serves any customers.

Fort Necessity Gas Storage, LLC is a wholly owned subsidiary of Atmos Pipeline and Storage, LLC, and was created in 2009 to construct and operate a non-regulated salt-cavern gas storage project in Louisiana. In March 2011, we recorded a $19.3 million charge to substantially write off our investment in Fort Necessity.

Trans Louisiana Gas Storage, Inc. owns a minority interest in a salt dome storage facility in Louisiana. This facility is used to serve utility and non-utility customers.

Trans Louisiana Gas Pipeline, Inc. owns and operates an intrastate pipeline system in Louisiana. This facility is used to serve utility and non-utility customers.

UCG Storage, Inc. owns certain storage field interests in Kentucky which are used to serve utility customers.

WKG Storage, Inc. owns certain storage field interests in Kentucky which are used to serve utility customers.

Service:	**Capitalized overhead (general)**
Description:	Overhead related to capital expenditures
Current Provider of Service	Shared Services Atmos Pipeline – Texas Division Louisiana Division operating division Kentucky/Mid-States Division operating division general office Colorado-Kansas Division operating division general office Mid-Tex Division Mississippi Division West Texas Division operating division general office
Current Use of Service	Rate divisions
Basis for allocation	The capitalized portion of the overhead costs are accumulated in overhead projects in Construction Work in Process (CWIP) by operating division (Shared Services described separately below). On a monthly basis, the overhead accumulated in these projects is applied to specific capital projects using a budgeted overhead application rate. The application rate is established at the beginning of the fiscal year based upon projected capital expenditures and is reviewed periodically and revised as necessary (at least annually) to reflect significant changes to the Company's capital expenditure plans. The budgeted rate applies overhead at both a division level and a state level (for divisions that consist of multiple states). Quarterly, any residual amount remaining in the overhead projects (positive or negative) are allocated to capital projects based on project spending during the quarter. Capitalized overhead that is specific to an operating division or state is allocated only to the capital projects for that operating division or state. Shared services overhead is based on an annual Capitalized Overhead Study by cost center to determine the capital application rate based on the expected capital versus expense activities of each cost center. Quarterly, the balance in the Shared Services Overhead Project is cleared to the capital projects across the regulated operations (both distribution and transmission) based on eligible spending during the quarter. Annually, a true-up is performed for certain cost centers, as necessary, who have been using an overall Company capital application rate, versus a rate for their specific cost center.

Service:	**Stores overhead**
Description:	Overhead related to management of materials is allocated to materials as purchased.
Current Provider of Service	Shared Services general office (Service Area 002)
Current Use of Service	Atmos Pipeline – Texas Division West Texas Division rate divisions Louisiana Division rate divisions Kentucky/Mid-States Division rate divisions Mid-Tex Division rate division Colorado-Kansas Division rate divisions Mississippi Division rate division
Basis for allocation	Overhead costs associated with inventory items (account 154), including rent, labor and supervision are accumulated by the operating division and recorded to the undistributed stores' overhead account (163). Each operating division sets an application rate at the beginning of the year based on projected overhead and materials activity. As material purchases with the expenditure type "with stores overhead" are incurred, the application rate is applied, and the overhead assigned is allocated to the same account as the material purchase. Periodically, the balance in the undistributed stores' overhead account is compared to the inventory account and a new rate is determined. Shared Services stores overhead is allocated monthly to the operating divisions based on direct operation and maintenance expenses for each applicable area or each operating division.

Service:	**O&M Expenses in Shared Services – Customer Support cost centers**
Description:	Includes all expenses for Customer Support. (Service Area 012)
Current Provider Of Service	Shared Services
Current Use of Service	West Texas Rate Divisions Mid-Tex Division Louisiana Rate Divisions Kentucky/Mid-States Rate Divisions Colorado-Kansas Rate Divisions Mississippi Division
Basis for allocation	Costs are allocated to the applicable operating division in total based on the average number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions. General office charges are allocated to rate divisions as applicable following the same methodology.

Service:	**O&M Expenses in Shared Services – General Office cost centers**
Description:	Includes O&M expenses in Shared Services – General Office. (Service Area 002)
Current Provider Of Service	Shared Services
Current Use of Service	Atmos Energy Louisiana Industrial Gas, LLC Trans Louisiana Gas Pipeline WKG Storage, Inc. West Texas Division Mid-Tex Division Atmos Pipeline – Texas Division Louisiana Division Kentucky/Mid-States Division Colorado-Kansas Division Mississippi Division Trans Louisiana Gas Storage Atmos Power Systems, Inc UCG Storage, Inc. Atmos Energy Holdings, Inc.
Basis for allocation	Costs from Shared Services are allocated to affiliates and operating divisions based on the composite factor as defined above, including the general office service areas as applicable. In addition, shared services departments which provide services to the Company's operating divisions and affiliates include those and operating divisions and affiliates in the composite factor and departments that do not provide services to the Company's affiliates and operating divisions do not include those affiliates and operating divisions in the composite factor.

Service:	**SSU – Customer Support taxes other than income taxes**
Description:	Includes all taxes other than income tax charged in Shared Services – Customer Support.
Current Provider Of Services	Shared Services
Current Use of Service	West Texas Rate Divisions Louisiana Rate Divisions Kentucky/Mid-States Rate Divisions Mid-Tex Division Colorado-Kansas Rate Divisions Mississippi Division
Basis for allocation	Costs are allocated to the applicable rate division level in total based on the average number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions. As applicable, the number of customers in the rate divisions is used to allocate from the operating division general office to the rate divisions.

Service:	**SSU – General Office taxes other than income taxes**
Description:	Includes all taxes other than income tax charged in Shared Services – General Office.
Current Provider Of Services	Shared Services
Current Use of Service	Atmos Energy Louisiana Industrial Gas, LLC Atmos Power Systems, Inc. WKG Storage, Inc. Trans Louisiana Gas Pipeline, Inc. West Texas Division Mid-Tex Division Atmos Pipeline – Texas Division Louisiana Division Kentucky/Mid-States Division Colorado-Kansas Division Mississippi Division UCG Storage, Inc. Atmos Energy Holdings, Inc.
Basis for allocation	Costs are allocated to the applicable operating divisions in total based on the Composite Factor as defined above, including the general office areas, as applicable.

Service:	**SSU – Customer Support depreciation**
Description:	Includes all depreciation charged in Shared Services – Customer Support.
Current Provider Of Services	Shared Services
Current Use of Service	West Texas Rate Divisions Louisiana Rate Divisions Kentucky/Mid-States Rate Divisions Mid-Tex Division Colorado-Kansas Rate Divisions Mississippi Division
Basis for allocation	Costs are generally allocated to the applicable rate division level in total based on the average number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions. For applicable divisions, the number of customers in the rate divisions is used to allocate from the operating division general office to the rate divisions. Depreciation associated with the Charles K. Vaughan ("CKV") Center is allocated based upon square footage, number of customers and employee training usage.

Service:	**SSU – General Office depreciation**
Description:	Includes all depreciation charged in Shared Services – General Office.
Current Provider Of Services	Shared Services
Current Use of Service	Atmos Energy Louisiana Industrial Gas, LLC WKG Storage, Inc. Trans Louisiana Gas Pipeline, Inc. West Texas Division Mid-Tex Division Atmos Pipeline – Texas Division Louisiana Division Kentucky/Mid-States Division Colorado-Kansas Division Mississippi Division UCG Storage, Inc. Atmos Energy Holdings, Inc.
Basis for allocation	Costs are generally allocated to the applicable operating divisions in total based on the Composite Factor as defined above, including the general office areas as applicable. The depreciation allocation for the Greenville Data Center is based upon the Composite Factor and square footage percent by operating division. The depreciation allocation for SSU General Office (Service Area 002) assets that support the enterprise excluding our Atmos Pipeline – Texas (APT) Division are based on a composite factor for the operating divisions, but excludes APT. The depreciation allocation for our Aligne billing system assets is based upon invoiced volumes from Aligne per operating division as a percentage of total volumes from Aligne.

Service:	**West Texas Division operating division general office O&M, depreciation, and taxes other than income taxes, to rate division level**
Description:	Allocation of operating division general office expenses to rate division levels
Current Provider of Service	West Texas Division operating division general office
Current Use of Service	West Texas Division rate divisions
Basis for allocation	Costs are allocated to the applicable operating divisions in total based on the Composite Factor as defined above, tailored to each rate division within the total West Texas Division.

Service:	**Colorado-Kansas Division operating division general office O&M, depreciation, and taxes other than income taxes, to rate division level**
Description:	Allocation of division general office expenses to rate division levels
Current Provider of Service	Colorado-Kansas Division operating division general office
Current Use of Service	Colorado-Kansas Division rate divisions.
Basis for allocation	Costs are allocated to the applicable rate divisions in total based on the Composite Factor as defined above, tailored to each rate division within the total Colorado-Kansas Division.

Service:	**Kentucky/Mid-States Division operating division general office O&M, depreciation, and taxes other than income taxes, to rate division level**
Description:	Allocation of division general office expenses to rate division levels
Current Provider of Service	Kentucky/Mid-States operating division general office
Current Use of Service	Kentucky/Mid-States Division rate divisions.
Basis for allocation	Costs are allocated to the applicable rate divisions in total based on the Composite Factor as defined above, tailored to each rate division within the total Kentucky/Mid-States Division.

Description of Relationship between Mid-Tex and Atmos Pipeline – Texas:

Mid-Tex and Atmos Pipeline – Texas (APT) Divisions provide services to their customers on an on-going basis throughout their service areas. The field operations include, but are not limited to, services related to pipeline integrity, measurement, compliance work, painting, right of way mowing and reclamation, leak surveys, patrolling, regulator maintenance, fence replacements, line repairs and line replacements. Costs that need to be allocated to both business units originate within Mid-Tex. Those charges are captured for Mid-Tex versus APT through direct charging to the specific project or through an allocation process.

Service:	**Mid-Tex/Atmos Pipeline – Texas Division - Intracompany Labor**
Description:	Mid-Tex employees' labor supporting APT operations
Current Provider Of Service	Mid-Tex
Current Use of Service	Atmos Pipeline – Texas
Basis for allocation	Mid-Tex supervisory and support employees who charge time to APT generally record their time through an allocation process with potentially certain time being recorded directly to a project if needed. Mid-Tex non-supervisory employees who charge time to APT generally record their time through the time reporting system directly to a project. Note – If APT employees are supporting the Mid-Tex operations, the above allocation would still be applicable only with the APT employees charging time accordingly to Mid-Tex.

Service:	**Mid-Tex/Atmos Pipeline – Texas Division - Non-Labor Expenses**
Description:	Allocation includes but is not limited to rents, heavy equipment, utilities, telecom, transportation (vehicles leased), uniforms, insurance, printing, and postage
Current Provider Of Service	Mid-Tex
Current Use of Service	Atmos Pipeline – Texas Division
Basis for allocation	Factors are primarily based on direct employee labor and contract labor, as needed. Allocations vary based on the cost center.

Service:	**Intercompany labor**
Description:	To the extent operating division employees provide labor services to an affiliate, the labor costs for the services will be charged to the appropriate affiliate.
Current Provider of Service	Louisiana Division Colorado-Kansas Division Kentucky/Mid-States Division Mississippi Division West Texas Division
Current Use of Service	UCG Storage, Inc. Atmos Energy Louisiana Industrial Gas, LLC WKG Storage, Inc. Trans Louisiana Gas Pipeline, Inc. Trans Louisiana Gas Storage, Inc.
Basis for allocation	Labor charges are captured through direct time sheet entries and transferred to the appropriate subsidiary receiving the labor services.

Service:	**Adjustments to Uncollectible Accounts Expense**
Description:	Allocation of additional expense amounts booked to adjust the Provision for Uncollectibles (Account 144)
Current Provider of Service	West Texas Division rate divisions Louisiana Division rate divisions Kentucky/Mid-States Division rate divisions Colorado-Kansas Division rate divisions Mid-Tex Division rate division Mississippi Division rate division
Current Use of Service	West Texas Division rate divisions Louisiana Division rate divisions Kentucky/Mid-States Division rate divisions Colorado-Kansas Division rate divisions Mid-Tex Division rate division Mississippi Division rate division
Basis of Intra-company Allocations	Costs are allocated to the rate divisions in total based on Sales Revenue or Margin.

Service:	**Intra-company labor allocation – other than operating division general office labor**
Description:	Certain employee activities cross multiple rate divisions within an operating division. The costs associated with such activities include labor, benefits, and associated taxes.
Current Provider of Service	Atmos Pipeline – Texas Division West Texas Division Louisiana Division Kentucky/Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Current Use of Service	Atmos Pipeline – Texas Division West Texas Division Louisiana Division Kentucky/Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Basis of Intra-company Allocations	Labor associated with cross-jurisdictional activities is charged to each jurisdiction based on the level of employee activity. The costs are captured either through direct time sheet entries or an allocation process.

Service:	**Other income and interest expense (All below the line accounts)**
Description:	Allocation of Shared Services' other income and interest expense (All below the line accounts)
Current Provider of Service	Shared Services
Current Use of Service	West Texas Division Louisiana Division Kentucky/Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division Atmos Pipeline – Texas Division
Basis for allocation	Interest Expense, Interest Income and Other Non-Operating Income in shared services are allocated to each utility division based on the budget allocation percentages. The budget allocation is based on projected average net investment by rate division for the budget year. For this purpose, 'net investment' is defined as regulatory rate base + goodwill. These allocation factors are the same throughout the fiscal year. The allocation stays in the account the charge was originally booked in. Headquarter allocation of below the line accounts to rate divisions follows the same process as described above.

Service:	**Gas cost between state jurisdictions for contiguous systems**
Description:	Gas costs that apply to contiguous systems that cross state jurisdictional boundaries are allocated between those rate jurisdictions.
Current Provider of Service	West Texas Division Colorado-Kansas Division Kentucky/Mid-States Division
Current Use of Service	West Texas Division Colorado-Kansas Division Kentucky/Mid-States Division
Basis of Allocations	Allocations are based upon throughput for the West Texas Division and the Colorado-Kansas Division's Southeast Colorado/Southwest Kansas operations. For the Colorado-Kansas Division's Kansas system and for the Kentucky/Mid-States Division, demand costs are allocated based on peak-day requirements. Commodity costs are allocated based upon throughput.

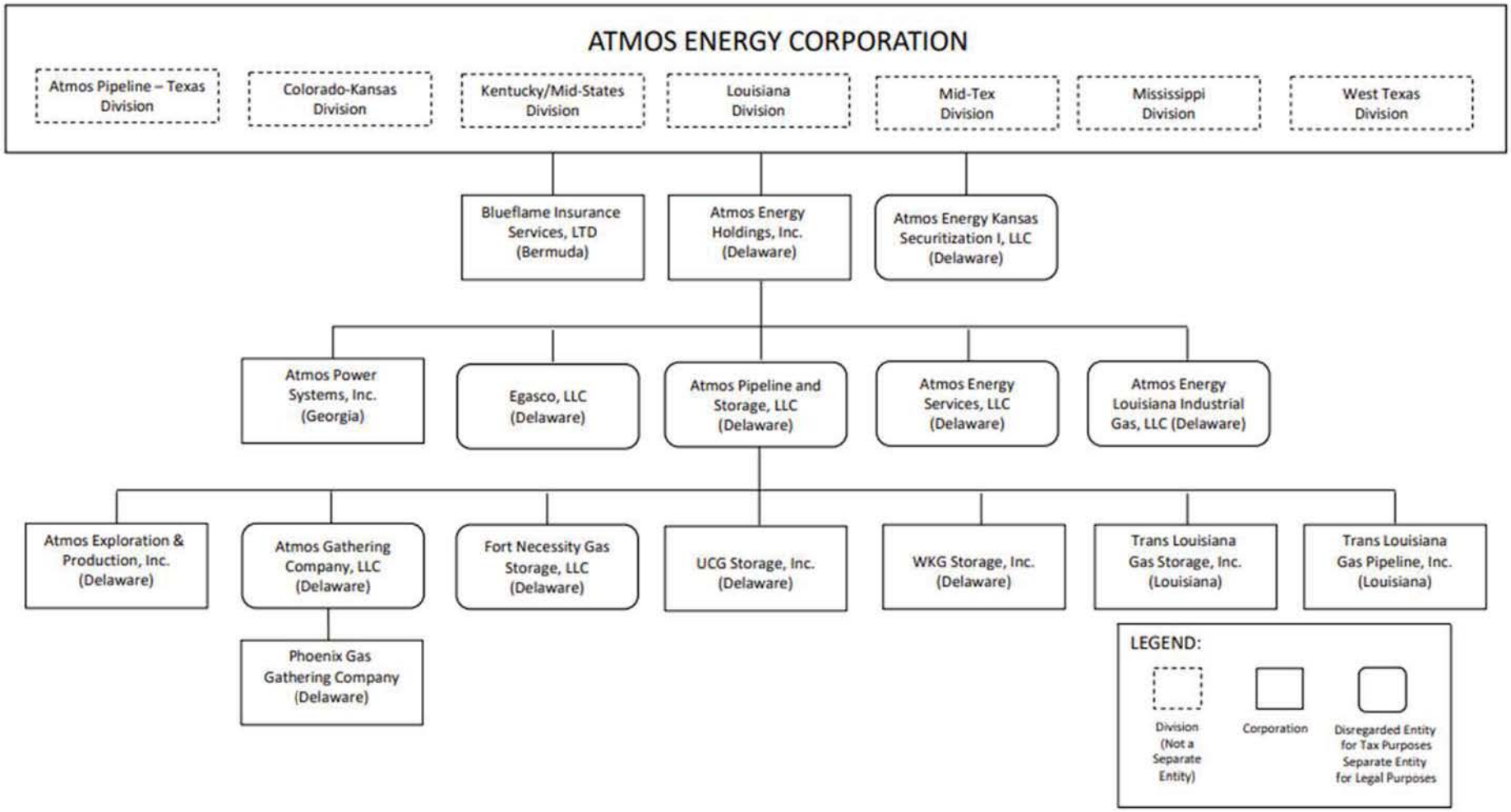
Service:	**Gas storage services between an operating division and an affiliate**
Description:	To the extent an operating division stores gas in a storage field owned by an affiliate, a rental fee for the use of the storage field shall be charged by the affiliate.
Current Provider of Service	UCG Storage, Inc. WKG Storage, Inc.
Current Use of Service	Kentucky/Mid-States Division
Basis for allocation	The annual demand charge between UCG Storage, Inc., and Atmos Energy Corporation (Tennessee operations only) is calculated based on fiscal year plant in service, gas inventory, actual operational costs incurred, and application of revenue and cost of capital conversion factors based on prior regulatory approval. In the calculation of the demand charge, costs not specifically related to a designated area are allocated to each affiliate based on the percentage of total plant servicing that affiliate. The annual demand charge between WKG Storage, Inc., and Atmos Energy Corporation (Kentucky operation only) is based on services provided at actual cost, market rate or as otherwise provided under tariff or contract.

Service:	**Gas storage services provided between affiliates**
Description:	To the extent an affiliate stores gas in a storage field owned by another affiliate, a fee for the use of the storage field shall be charged.
Current Provider of Service	Trans Louisiana Gas Storage, Inc.
Current Use of Service	Trans Louisiana Gas Pipeline, Inc.
Basis for allocation	The fee to the affiliate utilizing the storage service is based on services provided at actual cost, market rate or as otherwise provided under tariff.

Service:	**Property Insurance**
Description:	Blueflame Insurance Services, LTD provides a direct property insurance policy. The policy covers the property against all risks of direct physical loss or damage.
Current Provider of Service	Blueflame Insurance Services, LTD
Current Use of Service	Kentucky/Mid-States Division Colorado-Kansas Division Shared Services Louisiana Division Mississippi Division Mid-Tex Division West Texas Division Atmos Pipeline – Texas Division Atmos Energy Louisiana Industrial Gas, LLC Atmos Exploration & Production, Inc. Atmos Energy Services, LLC Atmos Power Systems, Inc. Trans Louisiana Gas Pipeline, Inc. Trans Louisiana Gas Storage, Inc. UCG Storage, Inc. WKG Storage, Inc. Atmos Gathering Company, LLC
Basis for allocation	Atmos Energy Corporation is invoiced by Blueflame Insurance Services. Costs are allocated based on the gross property, plant and equipment and gas stored underground balances at a rate division level.

Appendix A
As of April 1, 2024

As of October 28, 2022



BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

TESTIMONY OF THOMAS L. TROUP

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OF THOMAS L. TROUP, WITNESS FOR
ATMOS ENERGY CORPORATION

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EXHIBITS

Exhibit TLT-1 – Actual Monthly Billing Units and Volumes by Class

Exhibit TLT-2 – Summary of Annualized Adjustments

Exhibit TLT-3 – Summary of the Annualized Impact of Industrial Contract and Volume Changes

Exhibit TLT-4 – Summary of the Monthly Weather Adjustments

Exhibit TLT-5 – Summary of the Billing Determinants by Month

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Thomas L. Troup. I am Senior Rate Analyst for Rates & Regulatory Affairs (Shared Services) of Atmos Energy Corporation ("Atmos Energy" or the "Company"). My business address is 5420 LBJ Freeway, 1600 Lincoln Centre, Dallas, TX 75240.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. In 1985, I received my Bachelor of Science degree in Geology from Indiana University, Bloomington, Indiana. In 1990, I received my Master of Science degree in Geochemistry and Mineralogy from Pennsylvania State University, University Park, Pennsylvania. In 1991, I received my Master of Business Administration degree from the Kelley School of Business at Indiana University, Bloomington, Indiana. I am a member of the CFA Institute and a member of CFA Society Dallas/Ft Worth.

My professional experience includes more than 27 years in the utility industry and about four and a half years outside the utility industry. From 1991–1993, I was employed by Illinois Power Company with primary responsibilities in strategic planning, merger and acquisition analyses, and corporate development. I prepared Illinois Power's cost of equity analyses under the direction of the

company's cost of capital witness in the company's 1993 gas rate case before the Illinois Commerce Commission.

From 1993-1997, I was employed by LG&E Energy Corporation, the parent company of Louisville Gas and Electric Company at that time, where I held positions in strategic planning, financial planning and accounting, and trade finance and cash management.

From 1997–2002, I held positions outside the utility industry in treasury consulting, treasury product management, and financial management.

From 2002–2018, I was employed by Pacific Gas and Electric Company ("PG&E") working in the company's Regulatory Affairs organization, where my last position was as an Expert Rate Analyst in the Rates and Regulatory Analytics department.

In July 2020, I joined Atmos Energy Corporation in my current position where I perform billing determinant analyses, cost of service and other analyses for various regulatory filings, and state-level annual financial reporting.

Q. HAVE YOU SUBMITTED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. No.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY ON MATTERS BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes, I have sponsored testimony multiple times before the California Public Utilities Commission. I sponsored marginal cost testimony in PG&E's 2003, 2007, 2011, 2014, and 2017 General Rate Case ("GRC") Phase II showings for customer class cost of service; I testified on master meter discount calculations in PG&E's 2011 GRC Phase II showing; I sponsored testimony on the mobile home park electric master meter discount rate in PG&E's 2014 and 2017 GRC Phase II showings; I sponsored cost recovery testimony in PG&E's 2005 Critical Peak Pricing Application; I sponsored marginal cost-based fixed charge testimony in PG&E's 2018 Rate Design Window; and I sponsored marginal cost testimony for customer class cost of service on a marginal basis in PG&E's 2018 Gas Cost Allocation Proceeding.

Q. ARE YOU SPONSORING ANY OF THE FILING REQUIREMENTS IN THIS CASE, AND, IF SO, WHICH REQUIREMENTS?

A. Yes. I am sponsoring the following filing requirements:

FR 16(7)(c)	Description of all factors used in preparation of the forecast test period - income statement, operation and maintenance expenses, employee and labor expenses, capital construction budget;
FR 16(7)(h)	Financial Forecast (Revenues)
FR 16(7)(h)1	Operating Income Statement (Revenues)

FR16(7)(h)8	Mix of Gas Supply
FR 16(7)(h)14	Customer Forecast
FR 16(7)(h)15	Mcf Sales Volume Forecast
FR 16(8)(c)	Jurisdictional operating income summary for both base and forecast period with supporting schedules which provide breakdowns by major account group and individual account
FR 16(8)(d)	Summary of jurisdictional adjustments to operating income
FR 16(8)(i)	Comparative income statements, revenue and sales statistics, base period, forecast period and two (2) years beyond
FR 16(8)(k)	Comparative Financial Data
FR 16(8)(m)	Revenue Summary for Both the Period and Forecasted Period

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring Exhibits TLT-1 – TLT-5.

Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND EXHIBITS, AND THEIR ASSOCIATED SCHEDULES, AND MAKE THEM PART OF YOUR TESTIMONY?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, I will describe the methods used to forecast Company's revenues and volumes as they relate to the base period and test period in this case. Second, I will present the test period forecast of revenues and volumes.

III. PROCESS OF FORECASTING OF REVENUES AND VOLUMES

Q. PLEASE DESCRIBE THE GOALS OF FORECASTING REVENUE AND VOLUMES.

A. The goal of revenue forecasting, fundamentally, is to determine expected revenues for business planning purposes. The primary emphasis of the "revenue" forecasting process is the estimate of the Company's gross margin, which is that portion of revenues excluding purchased gas costs. Purchased gas costs, which are recovered through the Company's Gas Cost Adjustment ("GCA") mechanism, are calculated only as a final step in the process, to forecast gross revenues.

Revenue forecasting is an essential element of Atmos Energy's financial planning and affects the Company's level of operating and maintenance expenses, capital investment, and cash flow requirements.

Q. WHAT TYPES OF FACTORS ARE CONSIDERED IN ATMOS ENERGY'S REVENUE AND GROWTH FORECASTING PROCESS?

A. The forecast process can be segregated into two primary steps. The first step is an analysis of revenue trends over recent years to determine a baseline reference. The second step is the consideration of factors and issues expected to affect the budget period.

First, the analysis of historical revenue trends quantifies the net customer additions and Mcf requirements, by customer class. Using heating degree day ("HDD") data for the respective periods, the Mcf requirements are "weather-normalized" for residential, commercial and public authority sales customer classes. The HDD is a measure of the difference between average daily temperature and a 65 degree Fahrenheit base. Upon completing the analysis of historic data, customer growth and class usage trends may be identified.

Second, consideration is given to any factors that could either continue or alter historical trends. These factors include but are not limited to gas supply price outlook and consideration of its impact on the market, changing local economic conditions that could influence customer growth, and major industrial additions or plant closings.

Considered individually, these factors may have either a positive or negative effect upon forecasted revenue streams.

Q. WHAT TIME PERIOD TYPICALLY FORMS THE BASIS FOR REVENUE AND VOLUME FORECASTS?

A. Forecasts are typically prepared for Atmos Energy's fiscal year, which runs from October 1 to the following September 30.

Q. WHAT IS THE BASE PERIOD FOR THIS CASE?

A. The base period is January 1, 2024, to December 30, 2024.

Q. WHAT IS THE FORECASTED TEST PERIOD FOR THIS CASE?

A. The forecasted test period for this case is April 1, 2025, to March 31, 2026.

Q. DID THE COMPANY UTILIZE ITS TYPICAL REVENUE BUDGETING PROCESS TO DEVELOP THE BASE PERIOD AND FORECASTED TEST PERIOD REVENUES?

A. No. Although the simple two-step process of historical review and consideration of forward-looking factors is the same, the annual budget process is not developed at the level necessary for determining rate design billing determinants. For example, the typical annual revenue budget is based upon financial statistics reported to the customer class level, not to the rate classification / billing block level of detail. To build rate case quality billing data, Atmos Energy produced bill frequency reports to isolate correct determinants of bills rendered and volumes delivered by customer class as well as by rate classification for the 12-month period ending June 30, 2024. This 12-month period serves as the "reference period" to be

normalized and upon which forward-looking adjustments may be applied, ultimately resulting in a forecast of billing determinants for the test year period of April 1, 2025, to March 31, 2026.

Q. IS THE PROCESS FOR DEVELOPING THE BASE PERIOD AND FORECASTED TEST PERIOD REVENUES THE SAME AS PRIOR RATE CASE FILINGS?

A. Yes. The Commission found the Company's revenue forecast in Case No. 2013-00148, Case No. 2015-00343, Case No. 2017-00349, Case No. 2018-00281, and Case No. 2021-00214 to be reasonable and accepted the normalized base-rate revenues without adjustment.

Q. HOW WAS THE DATA FOR THE REFERENCE PERIOD GATHERED?

A. The unadjusted data for the reference period reflects the actual billing units and margins for all services during the twelve months ending June 30, 2024. This data was gathered from billing system reports for that period. Exhibit TLT-1 attached hereto provides the actual monthly billing units and volumes by class of service for the reference period ending June 30, 2024.

Q. WHAT STEPS WERE TAKEN TO FORECAST THE FUTURE TEST YEAR FROM THE BASELINE REFERENCE PERIOD?

A. First, the Company assessed appropriate pro-forma adjustments to the reference period to 1) reflect known and measurable service contract changes, load changes,

new industries and industry closings; and 2) adjust firm residential, commercial and public authority volumes to correlate to normal HDDs.

Then, forward-looking adjustments were considered to account for net customer growth or losses.

A summary of annualized adjustments for each of these steps is shown on Exhibit TLT-2 attached hereto.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO THE REFERENCE PERIOD, INCLUDING KEY ASSUMPTIONS, FOR INDUSTRIAL SALES AND TRANSPORTATION SERVICES.

A. Historical volume requirements for each transportation customer were reviewed, with adjustments made to account for expected changes by service type for future periods. For example, usage for a new industrial customer added midway through the reference period would not be representative of its forecast test period requirements. In this case, the customer's volumes would need to be "annualized" to reflect usage throughout the full twelve months. Adjustments were also made for industry closings, expansions or reductions, and contract changes altering a customer's service type or rate schedule. These adjustments ensured that known and measurable changes in industrial sales and transportation were reflected in our test period forecast. Exhibit TLT-3 attached hereto summarizes the annualized impact of industrial contract and volume changes, by service type.

Q. PLEASE DESCRIBE THE PROCESS EMPLOYED TO DETERMINE THE ADJUSTMENT FOR WEATHER VARIANCES DURING THE REFERENCE PERIOD.

A. Adjusting for variances from normal weather is a common practice. The methodology for determining composite degree days was based on a process instituted originally in Case No. 1999-070, which utilized the composite calculated weighting weather data from Paducah, Lexington and Louisville, Kentucky; Evansville, Indiana; and Nashville, Tennessee. The composite normal heating degree days were based upon the same weighting of the five weather stations, applying the National Oceanic and Atmospheric Administration ("NOAA") HDD data averages for the twenty-year period ending June 30, 2024. The Company has chosen a 20-year average HDD basis based on analysis required in the Commission Order in Case No. 2013-00148 and approved in Commission Orders in Case No. 2015-00343, Case No. 2017-00349, Case No. 2018-00281, and Case No. 2021-00214. Later, my testimony will describe this analysis. Exhibit TLT-4 attached hereto summarizes the monthly weather adjustment to the reference period resulting from the 16% warmer than normal period. Exhibit TLT-4 also provides details of the calculations of the respective weather adjustment for the weather sensitive residential, commercial and public authority classes.

Q. HOW ARE WEATHER NORMALIZATION ADJUSTMENT ("WNA") TARIFF REVENUES FACTORED INTO THE WEATHER ADJUSTMENT?

A. For the purpose of the weather adjustment, WNA revenues are ignored. The weather adjustment calculates the normalized volumes associated with normal weather, which will be priced out to demonstrate weather normalized revenues. Actual WNA revenues compensate for only a portion of those variances; those occurring during the WNA billing months of November 1 through April 30 each winter. The weather adjustment in this Case is intended to normalize the entire 12-month period.

Q. PLEASE DESCRIBE IN DETAIL THE HISTORICAL DATA CONSIDERED IN THE REVENUE AND VOLUME FORECASTING PROCESS.

A. To assess key historical trends necessary for the forecast, financial statistics for ten years were analyzed, noting the number of active customers served during that time and the total volumetric requirements by customer class. Actual sales volumes each year were adjusted for variances from normal weather, based on the current HDD composite and normal basis.

Based on the historical data, trends were noted for the customer count, net annual growth and weather normalized adjusted volumes per customer for residential, commercial and public authority classes.

Q. PLEASE DISCUSS THE HISTORICAL TRENDS OBSERVED AND THE ASSUMPTIONS USED IN THE DEVELOPMENT OF THE FORECAST TEST PERIOD BUDGET STARTING WITH NET CUSTOMER GROWTH.

A. Based on the net average annual customer growth over the past three years, I forecasted commercial customer growth of 50 customers per year. Based on the same analysis of residential and public authority classes, I forecasted zero net residential and public authority customer changes from the reference period to the test year.

Q. WHAT IS THE ASSUMPTION FOR FUTURE DECLINING USE TRENDS AS IT RELATES TO THE TEST YEAR?

A. In Case No. 1999-070 and in subsequent cases, Atmos Energy noted the long-standing trend of declining customer usage. The trend-line for the past ten years, however, shows no apparent further decline in average customer usage. Therefore, I have not forecasted a decline in residential, commercial or public authority sales usage in this Case.

Q. WHAT WERE THE ASSUMPTIONS FOR SERVICE CHARGES AND THE LATE PAYMENT FEES?

A. I forecasted the transaction-based service charges to remain flat, equal to the average experience in fiscal years 2017, 2018, and 2019 for G-1 commercial and public authority customers. This three-year period—rather than the last several

years—was selected as better representative of normal operations prior to multi-year temporary changes in practices in response to the COVID-19 pandemic.

Late payment fees were first adopted in Case No. 1999-070, beginning in mid-2000. Following Case No. 2021-00214, late payment fees were removed for G-1 residential customers and remained in place for G-1 commercial and public authority customers. Since that time (excluding COVID-19 pandemic-driven anomalies), we have observed that late payment fee revenue is proportionate to the total revenues billed for commercial and public authority classes. Based upon that correlation, I estimated late payment fees at a ratio equal to 0.64% and 0.56% of the total projected commercial and public authority class revenues, respectively.

Q. HOW WERE GAS COSTS PROJECTED FOR THE TEST YEAR?

A. Based upon the sales volumes projected, projected gas supply prices as stated in current NYMEX futures, and applying the Company's seasonal plans for storage injections, and withdrawals, I modeled the forward periods to estimate the gas costs to be recovered through future GCAs. This method was first created in conjunction with Case No. 1999-070 and has been refined over time to simulate interstate pipeline demand and commodity costs, retention, and other items recoverable through the GCA. This model was also utilized in the determination of storage cost balances for forward periods.

Q. IS THE FORECASTING PROCESS YOU HAVE DESCRIBED THE BEST METHOD TO USE FOR THE DEVELOPMENT OF THE TEST YEAR VOLUME AND REVENUE FORECAST IN THIS CASE?

A. Yes. The method of developing the forecast ensures a solid bridge of logical and measurable adjustments, building upon the actual performance of a recent reference period. This forecasting process has been employed in prior Kentucky cases and, in Case No. 2013-00148, Case No. 2015-00343, Case No. 2017-00349, Case No. 2018-00281, and Case No. 2021-00214 was found by the Commission to be reasonable with the normalized base-rate revenues accepted without adjustment.

Exhibit TLT-2 attached hereto summarizes each step of the process and applies current rates to the derived billing determinants. Exhibit TLT-5 summarizes the billing determinants for each month of the test year.

Q. PLEASE DESCRIBE HOW YOUR EXHIBITS ARE UTILIZED IN DETERMING SUMMARIZING THE REVENUE AT CURRENT RATES AS WELL AS RATES PROPOSED BY ATMOS ENERGY.

A. Company witness Brannon Taylor takes the summarized billing determinants from Exhibit TLT-5 and recalculates revenue at present rates, as shown in his Exhibit BCT-1 and BCT-2. Exhibit BCT-1 replicates my Exhibit TLT-2 walking forward each set of adjustments from the reference billing determinants to those forecast for the test period and adds in the revenue at proposed rates. Exhibit BCT-2 replicates

my Exhibit TLT-5 and applies the proposed rates to calculate the revenue at present rates. Mr. Taylor discusses how he developed the proposed rates in his testimony.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Thomas L. Troup, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Thomas L. Troup

STATE OF TEXAS

COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Thomas L. Troup on this the 23rd day of September, 2024.

Notary Public

My Commission Expires: September 1, 2028

Giselle R Heroy
My Commission Expires
9/1/2028
Notary ID130804842

EXHIBIT TLT-1

ATMOS ENERGY CORPORATION – KENTUCKY
BILL FREQUENCY DATA
REFERENCE PERIOD - TWELVE MONTHS ENDING 06/30/2024

Line No.	Class of Customers	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Number Of Bills	Mcf	Rate	Total Revenue
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	RESIDENTIAL (Rate G-1)																
2	FIRM BILLS	158,859	158,643	157,525	158,693	160,008	161,112	162,059	162,229	162,136	162,288	161,528	160,443	1,925,523		$19.30	$37,162,594
3	Sales: 1-300	164,018	143,655	162,593	210,110	597,469	1,216,075	1,994,247	1,802,824	1,055,528	767,067	312,100	185,751		8,611,439	1.5483	13,333,091
4	Sales: 301-15000	0	0	0	309	0	0	0	0	0	0	0	0		309	1.0762	332
5	Sales: Over 15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.8888	0
6	CLASS TOTAL (Mcf/month)	164,018	143,655	162,593	210,419	597,469	1,216,075	1,994,247	1,802,824	1,055,528	767,067	312,100	185,751	1,925,523	8,611,748		$50,496,017
7																	
8	FIRM COMMERCIAL (Rate G-1)																
9	FIRM BILLS	17,806	17,752	17,631	17,835	18,260	18,536	18,799	18,781	18,794	18,834	18,536	18,167	219,731		66.00	$14,502,246
10	Sales: 1-300	139,966	123,658	150,225	173,616	299,972	539,445	862,990	785,289	486,240	366,400	193,319	149,396		4,270,516	1.5483	6,612,039
11	Sales: 301-15000	21,463	14,136	50,017	78,742	42,365	72,611	156,952	123,852	54,190	37,375	20,833	19,686		692,223	1.0762	744,970
12	Sales: Over 15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.8888	0
13	CLASS TOTAL (Mcf/month)	161,429	137,795	200,243	252,358	342,336	612,056	1,019,942	909,141	540,430	403,775	214,153	169,082	219,731	4,962,739		$21,859,256
14																	
15	FIRM INDUSTRIAL (Rate G-1)																
16	FIRM BILLS	202	214	208	210	213	208	205	212	215	213	212	210	2,522		$66.00	$166,452
17	Sales: 1-300	8,452	8,628	9,211	10,771	23,719	33,813	43,948	45,008	34,440	27,358	16,430	9,573		271,351	1.5483	420,133
18	Sales: 301-15000	7,424	12,968	10,541	12,654	20,701	38,318	78,266	67,506	33,568	20,925	37,319	8,543		348,734	1.0762	375,307
19	Sales: Over 15000	-	-	-	-	-	-	-	-	-	-	-	-		0	0.8888	0
20	CLASS TOTAL (Mcf/month)	15,875	21,596	19,752	23,425	44,420	72,131	122,214	112,515	68,009	48,282	53,749	18,117	2,522	620,085		$961,892
21																	
22	FIRM PUBLIC AUTHORITY (Rate G-1)																
23	FIRM BILLS	1,490	1,493	1,496	1,504	1,502	1,507	1,516	1,503	1,507	1,504	1,513	1,483	18,018		$66.00	$1,189,188
24	Sales: 1-300	22,334	20,476	24,093	31,351	53,768	88,124	129,129	121,154	80,448	61,796	38,581	24,163		695,417	1.5483	1,076,715
25	Sales: 301-15000	2,875	2,580	900	4,146	6,764	12,252	31,691	28,565	10,449	6,337	6,665	4,029		117,253	1.0762	126,188
26	Sales: Over 15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.8888	0
27	CLASS TOTAL (Mcf/month)	25,209	23,056	24,993	35,497	60,532	100,376	160,820	149,719	90,897	68,133	45,246	28,192	18,018	812,670		$2,392,090
28																	
29	INTERRUPTIBLE COMMERCIAL (G-2)																
30	INT BILLS	2	2	2	2	3	3	3	3	3	3	4	2	32		520.00	$16,640
31	Sales: 1-15000	19	29	122	44	170	970	1,488	1,868	1,099	543	398	59		6,810	0.9557	6,509
32	Sales: Over 15000	-	-	-	-	-	-	-	-	-	-	-	-		0	0.7837	0
33	CLASS TOTAL (Mcf/month)	19	29	122	44	170	970	1,488	1,868	1,099	543	398	59	32	6,810		$23,149
34																	
35	INTERRUPTIBLE INDUSTRIAL (G-2)																
36	INT BILLS	5	5	6	6	6	5	8	8	6	6	6	6	73		520.00	$37,960
37	Sales: 1-15000	1,621	2,041	2,038	1,557	1,833	1,436	1,910	1,861	2,105	2,078	2,200	1,286		21,967	0.9557	20,994
38	Sales: Over 15000	7,296	8,056	10,760	10,023	14,052	20,977	20,051	17,548	21,736	20,225	16,426	16,784		183,933	0.7837	144,149
39	CLASS TOTAL (Mcf/month)	8,916	10,097	12,798	11,580	15,885	22,413	21,961	19,409	23,841	22,304	18,627	18,070	73	205,901		$203,103
40																	
41	TRANSPORTATION (T-4)																
42	TRANSPORTATION BILLS	119	119	119	119	119	121	119	118	119	119	120	119	1,434		520.00	$745,760
43	Trans Admin Fee	$5,950	$5,950	$5,950	$5,950	$5,950	$6,050	$5,950	$5,900	$6,000	$5,950	$6,000	$5,950				71,550
44	EFM Fee	$6,900	$7,050	$6,900	$7,050	$7,050	$7,200	$7,125	$7,200	$7,050	$7,125	$7,200	$7,200				85,050
45	Parking Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0				0
46	Firm Transport: 1-300	31,464	34,124	35,729	35,897	35,700	35,611	35,441	33,941	32,106	31,435	30,899	31,273		403,618	1.5483	624,923
47	Firm Transport: 301-15000	406,807	472,060	525,686	564,244	673,390	551,813	504,734	442,110	411,247	405,428	397,102	411,062		5,765,684	1.0762	6,205,029
48	Firm Transport: Over 15000	108,610	143,399	152,185	135,722	214,738	172,590	174,297	147,987	135,463	111,234	107,871	116,961		1,721,058	0.8888	1,529,676
49	CLASS TOTAL (Mcf/month)	546,881	649,583	713,600	735,862	923,828	760,015	714,472	624,039	578,815	548,097	535,872	559,296	1,434	7,890,360		$9,261,987
50																	
51	ECONOMIC DEV RIDER (EDR)																
52	Firm Transport: 1-300	0	0	0	0	0	0	0	0	0	0	0	0		0	1.1612	$0
53	Firm Transport: 301-15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.8072	0
54	Firm Transport: Over 15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.6666	0
55	CLASS TOTAL (Mcf/month)	0	0	0	0	0	0	0	0	0	0	0	0		0		$0
56																	

EXHIBIT TLT-1

ATMOS ENERGY CORPORATION – KENTUCKY
BILL FREQUENCY DATA
REFERENCE PERIOD - TWELVE MONTHS ENDING 06/30/2024

Line No.	Class of Customers	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Number Of Bills	Mcf	Rate	Total Revenue
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
57	TRANSPORTATION (T-3)																
58	TRANSPORTATION BILLS	70	70	70	70	70	70	70	70	71	71	71	71	844		520.00	$438,880
59	Trans Admin Fee	$3,450	$3,450	$3,450	$3,450	$3,450	$3,450	$3,450	$3,450	$3,500	$3,500	$3,500	$3,500				41,600
60	EFM Fee	$3,900	$3,900	$3,900	$3,900	$3,900	$3,900	$3,900	$3,900	$3,975	$3,975	$3,975	$3,975				47,100
61	Parking Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0				0
62	Interrupt Transport: 1-15000	397,640	442,352	463,475	463,884	486,045	445,165	434,683	424,391	423,537	416,313	401,974	388,998		5,188,458	0.9557	4,958,609
63	Interrupt Transport: Over 15000	247,659	313,001	310,633	314,148	354,311	308,384	319,776	277,574	270,524	272,196	245,261	173,601		3,407,069	0.7837	2,670,120
64	CLASS TOTAL (Mcf/month)	645,299	755,353	774,107	778,032	840,356	753,549	754,460	701,965	694,061	688,509	647,235	562,599	844	8,595,526		$8,156,309
65																	
66	SPECIAL CONTRACTS																
67	TRANSPORTATION BILLS	13	13	13	13	13	13	14	14	14	14	13	13	164		520.00	$85,360
68	Trans Admin Fee	$650	$650	$650	$650	$650	$650	$700	$700	$700	$700	$650	$650				8,000
69	EFM Fee	$750	$750	$750	$750	$750	$750	$825	$825	$825	$825	$750	$750				9,300
70	Parking / Pooling Fees	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0				0
71	Transported Volumes	1,070,907	1,145,895	1,197,327	1,267,205	1,506,121	1,364,198	1,441,195	1,295,904	1,248,479	1,144,871	1,295,397	1,197,574		15,175,074	Various	
72	Charges for Transport Volumes	$198,184	$243,680	$213,683	$186,162	$227,311	$212,628	$231,042	$278,119	$251,729	$264,888	$243,563	$225,099				2,776,087
73	CLASS TOTAL (Mcf/month)	1,070,907	1,145,895	1,197,327	1,267,205	1,506,121	1,364,198	1,441,195	1,295,904	1,248,479	1,144,871	1,295,397	1,197,574	164	15,175,074		$2,878,747

EXHIBIT TLT-2

ATMOS ENERGY CORPORATION – KENTUCKY
SUMMARY OF REVENUE AT PRESENT RATES
TEST YEAR ENDING MARCH 31 2026

Line No.	Description	Block (Mcf)	Reference Period - Twelve Months Ending 06/30/2024 Number of Bills, Units	Volumes As Metered	Contract Adj. Bills and Volumes	Weather Adj. Volumes (NOAA 2004–2024)	Total Volumes	Forward-looking Adjustments To Test Year Customer Growth Forecast	Conservation & Efficiency Adjustments	Total Test Year Volumes	Present Margin	Present Revenue
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(i)	(j)	(k)
1	Sales											
2	Firm Sales (G-1)	Customer Chrg	1,925,523					0			$19.30	$37,162,594
3		Customer Chrg	240,271		2			1,052			66.00	15,927,450
4		0 - 300		13,848,723	506	1,982,025	15,831,254	24,087	0	15,855,342	1.5483	24,548,826
5		301 - 15,000		1,158,518	(1,109)	64,221	1,221,630	3,822	0	1,225,452	1.0762	1,318,831
6		Over 15,000		0	0	0	0	0	0	-	0.8888	0
7	Interruptible Sales (G-2)	Customer Chrg	105		0						520.00	54,600
8		0 - 15,000		28,778	0		28,778			28,778	0.9557	27,503
9		Over 15,000		183,933	0		183,933			183,933	0.7837	144,149
10												
11	Transportation											
12	Customer Charges (T-4)	Customer Chrg	1,434		(19)						520.00	735,880
13	Customer Charges (T-3)	Customer Chrg	844		8						520.00	443,040
14	Customer Charges (SpK)	Customer Chrg	164		(10)						520.00	80,160
15	Transp. Adm. Fee	Customer Chrg	2,423		(21)						50.00	120,100
16	Parked Volumes [1]			-	0						0.00	0
17	EFM Charges										Various	139,875
18	Firm Transportation (T-4)	0 - 300		403,618	2,867		406,485			406,485	1.5483	629,361
19		301 - 15,000		5,765,684	21,096		5,786,780			5,786,780	1.0762	6,227,732
20		Over 15,000		1,721,058	(4,252)		1,716,805			1,716,805	0.8888	1,525,897
21	Economic Dev Rider (EDR)	301 - 15,000		0	0		0			0	0.8072	0
22		Over 15,000		0	0		0			0	0.6666	0
23	Interruptible Transportation (T-3)	0 - 15,000		5,188,458	18,957		5,207,415			5,207,415	0.9557	4,976,726
24		Over 15,000		3,407,069	0		3,407,069			3,407,069	0.7837	2,670,120
25	Total Special Contracts [2]			15,175,074	330,108		15,505,182			15,505,182	Various	3,022,030
26												
27	Total Tariff		2,168,341	46,880,912	368,173	2,046,246	49,295,331	28,962	0	49,323,241		99,754,874
28												
29	Other Revenues											58,912
30	Late Payment Fees											367,462
31	Total Gross Profit											100,181,248
32												
33	Gas Costs											87,640,898
34												
35	Total Revenue											$ 187,822,146
36												
37	[1] Parked Volumes not included in Total Deliveries.											
38	[2] Based on confidential information.											

EXHIBIT TLT-3

ATMOS ENERGY CORPORATION – KENTUCKY
VOLUME AND CONTRACT ADJUSTMENTS
REFERENCE PERIOD - TWELVE MONTHS ENDING 06/30/2024

Line No.	Class of Customers	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Number Of Bills	Mcf	Rate	Total Revenue
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	RESIDENTIAL (Rate G-1)																
2	FIRM BILLS													0		$19.30	$0
3	Sales: 1-300	0	0	0	309	0	0	0	0	0	0	0	0		309	1.5483	478
4	Sales: 301-15000	0	0	0	(309)	0	0	0	0	0	0	0	0		(309)	1.0762	(332)
5	Sales: Over 15000						0								0	0.8888	0
6	CLASS TOTAL (Mcf/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0		$146
7																	
8	FIRM COMMERCIAL (Rate G-1)																
9	FIRM BILLS															66.00	$0
10	Sales: 1-300															1.5483	0
11	Sales: 301-15000	0	0	0	0	0	0	0	0	0	0	0	0			1.0762	0
12	Sales: Over 15000	0	0	0	0	0	0	0	0	0	0	0	0			0.8888	0
13	CLASS TOTAL (Mcf/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0		$0
14																	
15	FIRM INDUSTRIAL (Rate G-1)																
16	FIRM BILLS	1	1	0	0	0	0	0	0	0	0	0	0	2		66.00	$132
17	Sales: 1-300	2	21	31	52	(209)	300	0	0	0	0	0	0		197	1.5483	306
18	Sales: 301-15000	0	0	0	0	(836)	36	0	0	0	0	0	0		(800)	1.0762	(861)
19	Sales: Over 15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.8888	0
20	CLASS TOTAL (Mcf/month)	2	21	31	52	(1,045)	336	0	0	0	0	0	0	2	(603)		($424)
21																	
22	FIRM PUBLIC AUTHORITY (Rate G-1)																
23	FIRM BILLS													0		66.00	$0
24	Sales: 1-300														0	1.5483	0
25	Sales: 301-15000														0	1.0762	0
26	Sales: Over 15000														0	0.8888	0
27	CLASS TOTAL (Mcf/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0		$0
28																	
29	INTERRUPTIBLE COMMERCIAL (G-2)																
30	INT BILLS													0		520.00	$0
31	Sales: 1-15000														0	0.9557	0
32	Sales: Over 15000														0	0.7837	0
33	CLASS TOTAL (Mcf/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0		$0
34																	
35	INTERRUPTIBLE INDUSTRIAL (G-2)																
36	INT BILLS	0	0	0	0	0	0	0	0	0	0	0	0	0		520.00	$0
37	Sales: 1-15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.9557	0
38	Sales: Over 15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.7837	0
39	CLASS TOTAL (Mcf/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0		$0

EXHIBIT TLT-3

ATMOS ENERGY CORPORATION – KENTUCKY
VOLUME AND CONTRACT ADJUSTMENTS
REFERENCE PERIOD - TWELVE MONTHS ENDING 06/30/2024

Line No.	Class of Customers	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Number Of Bills	Mcf	Rate	Total Revenue
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
40																	
41	TRANSPORTATION (T-4)																
42	TRANSPORTATION BILLS	(2)	(2)	(2)	(2)	(2)	(3)	(1)	0	(1)	(1)	(2)	(1)	(19)		520.00	($9,880)
43	Trans Admin Fee	($100)	($100)	($100)	($100)	($100)	($150)	($50)	$0	($50)	($50)	($100)	($50)				(950)
44	EFM Fee	($150)	($150)	($150)	($150)	($150)	($225)	($75)	$0	($75)	($75)	($150)	($75)				(1,425)
45	Parking Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0				0
46	Firm Transport: 1-300	320	411	423	347	197	(390)	0	300	150	306	503	300		2,867	1.5483	4,439
47	Firm Transport: 301-15000	(2,000)	(140)	(353)	3,548	3,372	(766)	(1,155)	(1,787)	322	7,536	9,738	2,782		21,096	1.0762	22,703
48	Firm Transport: Over 15000	0	0	0	0	0	0	0	(4,252)	0	0	0	0		(4,252)	0.8888	(3,779)
49	CLASS TOTAL (Mcf/month)	(1,680)	271	69	3,894	3,569	(1,156)	(1,155)	(5,740)	472	7,842	10,241	3,082	(19)	19,711		$11,108
50																	
51	ECONOMIC DEV RIDER (EDR)																
52	Firm Transport: 1-300	0	0	0	0	0	0	0	0	0	0	0	0		0	1.1612	$0
53	Firm Transport: 301-15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.8072	0
54	Firm Transport: Over 15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.6666	0
55	CLASS TOTAL (Mcf/month)	0	0	0	0	0	0	0	0	0	0	0	0		0		$0
56																	
57	TRANSPORTATION (T-3)																
58	TRANSPORTATION BILLS	1	1	1	1	1	1	1	1	0	0	0	0	8		520.00	$4,160
59	Trans Admin Fee	$50	$50	$50	$50	$50	$50	$50	$50	$0	$0	$0	$0				400
60	EFM Fee	$75	$75	$75	$75	$75	$75	$75	$75	$0	$0	$0	$0				600
61	Parking Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0				0
62	Interrupt Transport: 1-15000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	1,975	982	0	0		18,957	0.9557	18,117
63	Interrupt Transport: Over 15000	0	0	0	0	0	0	0	0	0	0	0	0		0	0.7837	0
64	CLASS TOTAL (Mcf/month)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	1,975	982	0	0	8	18,957		$23,277
65																	
66	SPECIAL CONTRACTS																
67	TRANSPORTATION BILLS	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	0	0	(10)		520.00	($5,200)
68	Trans Admin Fee	($50)	($50)	($50)	($50)	($50)	($50)	($50)	($50)	($50)	($50)	$0	$0				(500)
69	EFM Fee	($75)	($75)	($75)	($75)	($75)	($75)	($75)	($75)	($75)	($75)	$0	$0				(750)
70	Parking Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0				0
71	Transported Volumes	24,805	25,430	26,001	29,745	29,203	27,561	26,205	24,560	27,444	29,154	30,000	30,000		330,108	Various	
72	Charges for Transport Volumes	$18,628	$19,059	$19,453	$22,037	$21,662	$20,530	$19,594	$18,475	$20,450	$21,629	$22,212	$22,212				245,942
73	CLASS TOTAL (Mcf/month)	24,805	25,430	26,001	29,745	29,203	27,561	26,205	24,560	27,444	29,154	30,000	30,000	(10)	330,108		$239,492

EXHIBIT TLT-4 (A)

ATMOS ENERGY CORPORATION – KENTUCKY
WEATHER ADJUSTMENT—BASE NOAA 2004–2024
REFERENCE PERIOD - TWELVE MONTHS ENDING 06/30/2024

Line No.	Class of Customers	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Number Of Bills	Mcf	Rate	Total Revenue
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	RESIDENTIAL (Rate G-1)																
2	FIRM BILLS													0		$19.30	$0
3	Sales: 1-300	(10,077)	10,077	(5,865)	89,216	307,383	310,242	(146,379)	200,289	335,687	114,960	122,514	(1,202)		1,326,845	1.5483	2,054,354
4	Sales: 301-15000														0	1.0762	0
5	Sales: Over 15000														0	0.8888	0
6	CLASS TOTAL (Mcf/month)	(10,077)	10,077	(5,865)	89,216	307,383	310,242	(146,379)	200,289	335,687	114,960	122,514	(1,202)	0	1,326,845		$2,054,354
7																	
8	FIRM COMMERCIAL (Rate G-1)																
9	FIRM BILLS													0		66.00	$0
10	Sales: 1-300	(10,049)	10,401	(37,548)	(25,238)	134,687	153,993	(65,079)	89,830	171,064	82,831	62,760	(2,677)		564,974	1.5483	874,750
11	Sales: 301-15000	(1,541)	1,189	(12,502)	(11,447)	19,022	20,728	(11,836)	14,168	19,064	8,449	6,764	(353)		51,706	1.0762	55,646
12	Sales: Over 15000														0	0.8888	0
13	CLASS TOTAL (Mcf/month)	(11,590)	11,590	(50,050)	(36,685)	153,709	174,721	(76,915)	103,998	190,128	91,280	69,524	(3,030)	0	616,680		$930,395
14																	
15	FIRM PUBLIC AUTHORITY (Rate G-1)																
16	FIRM BILLS													0		$66.00	$0
17	Sales: 1-300	(975)	977	(450)	262	19,646	26,561	(4,150)	13,248	25,291	10,778	706	(1,688)		90,206	1.5483	139,666
18	Sales: 301-15000	(125)	123	(17)	35	2,471	3,693	(1,019)	3,123	3,285	1,105	122	(281)		12,515	1.0762	13,469
19	Sales: Over 15000														0	0.8888	0
20	CLASS TOTAL (Mcf/month)	(1,100)	1,100	(467)	297	22,117	30,254	(5,169)	16,371	28,576	11,883	828	(1,969)	0	102,721		$153,134

ATMOS ENERGY CORPORATION – KENTUCKY
NORMALIZATION OF VOLUMES FOR WEATHER
REFERENCE PERIOD - TWELVE MONTHS ENDING 06/30/2024
(WEATHER BASIS: NOAA DATA FOR 20 YEARS ENDING JUNE 2024)

Line	Month	Base Period – 12 Months Ending June 2024											
		Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Lagged Actual HDDs	0	0	0	56	274	583	799	729	411	304	65	0
2	Lagged Normal HDDs	0	0	2	71	362	657	806	879	588	345	133	14
3	Calendar Normal HDDs	0	0	16	205	511	798	838	728	482	220	59	0
4													
5	RESIDENTIAL (Rate G-1)												
6													
7	Annual Customer Growth												
8	Annual Base Load Decline												
9	Annual Total Load Decline												
10													
11	Actual Constand Load	153,941	153,732	152,649	153,780	155,055	156,125	157,042	157,207	157,117	157,264	156,528	155,476
12	Actual Heat Load	10,077	(10,077)	9,945	56,638	442,415	1,059,951	1,837,205	1,645,617	898,412	609,802	155,572	30,275
13	Heat Load / Customer	0.063	(0.064)	0.063	0.357	2.765	6.579	11.337	10.144	5.541	3.758	0.963	0.189
14	Actual X Coefficient	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129
15	Product	0	0	0.0259	0.9191	4.686	8.5046	10.4334	11.3784	7.6115	4.4659	1.7216	0.1812
16	Base Load	0.9690	0.9690	0.9690	0.9690	0.9690	0.9690	0.9690	0.9690	0.9690	0.9690	0.9690	0.9690
17	Normal Usage / Customer	0.9690	0.9690	0.9949	1.8881	5.6550	9.4736	11.4024	12.3474	8.5805	5.4349	2.6906	1.1502
18	No. of Customers	158,859	158,643	157,525	158,693	160,008	161,112	162,059	162,229	162,136	162,288	161,528	160,443
19	Normalized Volumes	153,941	153,732	156,728	299,635	904,852	1,526,318	1,847,869	2,003,113	1,391,215	882,026	434,614	184,549
20	Actual Volumes	164,018	143,655	162,593	210,419	597,469	1,216,075	1,994,247	1,802,824	1,055,528	767,067	312,100	185,751
21	Normalized Volume Including Unbilled	153,941	153,732	185,274	574,897	1,213,463	1,820,386	1,914,998	1,686,007	1,168,737	619,432	279,892	155,476
22	Normalized Calendar Volumes	154,133	153,923	185,505	575,613	1,214,974	1,822,652	1,917,382	1,688,106	1,170,191	620,203	280,241	155,670
23													
24	Weather Adjustment	(10,077)	10,077	(5,865)	89,216	307,383	310,242	(146,379)	200,289	335,687	114,960	122,514	(1,202)
25													
26	Tier 1	(10,077)	10,077	(5,865)	89,216	307,383	310,242	(146,379)	200,289	335,687	114,960	122,514	(1,202)
27	Tier 2												
28	Tier 3												
29	Total	(10,077)	10,077	(5,865)	89,216	307,383	310,242	(146,379)	200,289	335,687	114,960	122,514	(1,202)
30													
31													

ATMOS ENERGY CORPORATION – KENTUCKY
NORMALIZATION OF VOLUMES FOR WEATHER
REFERENCE PERIOD - TWELVE MONTHS ENDING 06/30/2024
(WEATHER BASIS: NOAA DATA FOR 20 YEARS ENDING JUNE 2024)

Line	Month	Base Period – 12 Months Ending June 2024											
		Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Lagged Actual HDDs	0	0	0	56	274	583	799	729	411	304	65	0
2	Lagged Normal HDDs	0	0	2	71	362	657	806	879	588	345	133	14
3	Calendar Normal HDDs	0	0	16	205	511	798	838	728	482	220	59	0
4													
32	FIRM COMMERCIAL (Rate G-1)												
33													
34	Annual Customer Growth												
35	Annual Base Load Decline												
36	Annual Total Load Decline												
37													
38	Actual Constand Load	149,839	149,385	148,366	150,083	153,659	155,982	158,195	158,044	158,153	158,490	155,982	152,877
39	Actual Heat Load	11,590	(11,590)	51,876	102,275	188,677	456,074	861,747	751,097	382,277	245,285	58,171	16,205
40	Heat Load / Customer	0.651	(0.653)	2.942	5.735	10.333	24.605	45.840	39.992	20.340	13.024	3.138	0.892
41	Actual X Coefficient	0.0518	0.0518	0.0518	0.0518	0.0518	0.0518	0.0518	0.0518	0.0518	0.0518	0.0518	0.0518
42	Product	0	0	0.1036	3.6776	18.7506	34.0308	41.7486	45.5298	30.4568	17.8701	6.889	0.7252
43	Base Load	8.4151	8.4151	8.4151	8.4151	8.4151	8.4151	8.4151	8.4151	8.4151	8.4151	8.4151	8.4151
44	Normal Usage / Customer	8.4151	8.4151	8.5187	12.0927	27.1657	42.4459	50.1637	53.9449	38.8719	26.2852	15.3041	9.1403
45	No. of Customers	17,806	17,752	17,631	17,835	18,260	18,536	18,799	18,781	18,794	18,834	18,536	18,167
46	Normalized Volumes	149,839	149,385	150,193	215,673	496,045	786,777	943,027	1,013,139	730,558	495,055	283,676	166,051
47	Actual Volumes	161,429	137,795	200,243	252,358	342,336	612,056	1,019,942	909,141	540,430	403,775	214,153	169,082
48	Normalized Volume Including Unbilled	149,839	149,385	162,978	339,463	636,973	922,153	974,187	866,246	627,369	373,111	212,629	152,877
49	Normalized Calendar Volumes	150,168	149,712	163,336	340,207	638,370	924,176	976,323	868,145	628,745	373,929	213,095	153,212
50													
51	Weather Adjustment	(11,590)	11,590	(50,050)	(36,685)	153,709	174,721	(76,915)	103,998	190,128	91,280	69,524	(3,030)
52													
53	Tier 1	(10,049)	10,401	(37,548)	(25,238)	134,687	153,993	(65,079)	89,830	171,064	82,831	62,760	(2,677)
54	Tier 2	(1,541)	1,189	(12,502)	(11,447)	19,022	20,728	(11,836)	14,168	19,064	8,449	6,764	(353)
55	Tier 3	-	-	-	-	-	-	-	-	-	-	-	-
56	Total	(11,590)	11,590	(50,050)	(36,685)	153,709	174,721	(76,915)	103,998	190,128	91,280	69,524	(3,030)
57													
58													

ATMOS ENERGY CORPORATION – KENTUCKY
NORMALIZATION OF VOLUMES FOR WEATHER
REFERENCE PERIOD - TWELVE MONTHS ENDING 06/30/2024
(WEATHER BASIS: NOAA DATA FOR 20 YEARS ENDING JUNE 2024)

Line	Month	Base Period – 12 Months Ending June 2024 Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Lagged Actual HDDs	0	0	0	56	274	583	799	729	411	304	65	0
2	Lagged Normal HDDs	0	0	2	71	362	657	806	879	588	345	133	14
3	Calendar Normal HDDs	0	0	16	205	511	798	838	728	482	220	59	0
4													
59	FIRM PUBLIC AUTHORITY (Rate G-1)												
60													
61	Annual Customer Growth												
62	Annual Base Load Decline												
63	Annual Total Load Decline												
64													
65	Actual Constand Load	24,108	24,157	24,205	24,335	24,302	24,383	24,529	24,318	24,383	24,335	24,480	23,995
66	Actual Heat Load	1,100	(1,100)	788	11,162	36,230	75,993	136,291	125,401	66,514	43,799	20,766	4,197
67	Heat Load / Customer	0.739	(0.737)	0.527	7.422	24.121	50.427	89.902	83.434	44.136	29.121	13.725	2.830
68	Actual X Coefficient	0.1073	0.1073	0.1073	0.1073	0.1073	0.1073	0.1073	0.1073	0.1073	0.1073	0.1073	0.1073
69	Product	0	0	0.2146	7.619	38.8463	70.5029	86.4921	94.3258	63.0985	37.0221	14.2723	1.5023
70	Base Load	16.1799	16.1799	16.1799	16.1799	16.1799	16.1799	16.1799	16.1799	16.1799	16.1799	16.1799	16.1799
71	Normal Usage / Customer	16.1799	16.1799	16.3945	23.7989	55.0262	86.6828	102.6720	110.5057	79.2784	53.2020	30.4522	17.6822
72	No. of Customers	1,490	1,493	1,496	1,504	1,502	1,507	1,516	1,503	1,507	1,504	1,513	1,483
73	Normalized Volumes	24,108	24,157	24,526	35,794	82,649	130,631	155,651	166,090	119,473	80,016	46,074	26,223
74	Actual Volumes	25,209	23,056	24,993	35,497	60,532	100,376	160,820	149,719	90,897	68,133	45,246	28,192
75	Normalized Volume Including Unbilled	24,108	24,157	26,774	57,420	106,665	153,433	160,857	141,736	102,331	59,841	34,059	23,995
76	Normalized Calendar Volumes	24,108	24,157	26,774	57,421	106,667	153,436	160,859	141,738	102,332	59,842	34,060	23,995
77													
78	Weather Adjustment	(1,100)	1,100	(467)	297	22,117	30,254	(5,169)	16,371	28,576	11,883	828	(1,969)
79													
80	Tier 1	(975)	977	(450)	262	19,646	26,561	(4,150)	13,248	25,291	10,778	706	(1,688)
81	Tier 2	(125)	123	(17)	35	2,471	3,693	(1,019)	3,123	3,285	1,105	122	(281)
82	Tier 3	-	-	-	-	-	-	-	-	-	-	-	-
83	Total	(1,100)	1,100	(467)	297	22,117	30,254	(5,169)	16,371	28,576	11,883	828	(1,969)

EXHIBIT TLT-5

ATMOS ENERGY CORPORATION – KENTUCKY
BILL FREQUENCY WITH KNOWN & MEASURABLE ADJUSTMENTS
TEST YEAR ENDING MARCH 31 2026
CURRENT RATES

Line No.	Class of Customers	Rate	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Total Billing Units
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	RESIDENTIAL (Rate G-1)		$4,497,799	$3,790,404	$3,382,286	$3,304,326	$3,299,833	$3,282,895	$3,526,700	$4,489,137	$5,472,659	$5,988,794	$6,232,440	$5,283,243	$52,550,517
2	FIRM BILLS	$19.30	162,288	161,528	160,443	158,859	158,643	157,525	158,693	160,008	161,112	162,059	162,229	162,136	1,925,523
3	Sales: 1-300	1.5483	882,026	434,614	184,549	153,941	153,732	156,728	299,635	904,852	1,526,318	1,847,869	2,003,113	1,391,215	9,938,593
4	Sales: 301-15000	1.0762	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Sales: Over 15000	0.8888	0	0	0	0	0	0	0	0	0	0	0	0	0
6	CLASS TOTAL (Mcf/month)		882,026	434,614	184,549	153,941	153,732	156,728	299,635	904,852	1,526,318	1,847,869	2,003,113	1,391,215	9,938,593
7	Gas Charge per Mcf		$4.58	$4.93	$4.93	$4.93	$5.30	$5.30	$5.30	$5.33	$5.33	$5.33	$4.89	$4.89	
8	Gas Costs		$4,040,819	$2,144,025	$910,409	$759,418	$814,618	$830,496	$1,587,751	$4,822,698	$8,134,995	$9,848,803	$9,800,500	$6,806,706	$50,501,238
9															
10	FIRM COMMERCIAL (Rate G-1)		$1,993,207	$1,654,025	$1,450,975	$1,405,636	$1,403,551	$1,386,296	$1,487,571	$1,954,909	$2,410,511	$2,646,438	$2,757,770	$2,349,469	$22,900,359
11	FIRM BILLS	66.00	18,884	18,586	18,217	17,906	17,852	17,731	17,935	18,360	18,636	18,899	18,881	18,894	220,781
12	Sales: 1-300	1.5483	450,438	256,777	147,123	130,646	134,814	113,316	149,215	437,071	697,238	802,225	879,857	660,856	4,859,577
13	Sales: 301-15000	1.0762	45,948	27,672	19,386	20,034	15,412	37,728	67,675	61,727	93,850	145,901	138,767	73,650	747,751
14	Sales: Over 15000	0.8888	0	0	0	0	0	0	0	0	0	0	0	0	0
15	CLASS TOTAL (Mcf/month)		496,386	284,449	166,509	150,680	150,226	151,044	216,890	498,799	791,088	948,126	1,018,624	734,506	5,607,328
16	Gas Charge per Mcf		$4.58	$4.93	$4.93	$4.93	$5.30	$5.30	$5.30	$5.33	$5.33	$5.33	$4.89	$4.89	
17	Gas Costs		$2,274,090	$1,403,237	$821,416	$743,332	$796,040	$800,376	$1,149,288	$2,658,506	$4,216,356	$5,053,340	$4,983,754	$3,593,667	$28,493,403
18															
19	FIRM INDUSTRIAL (Rate G-1)		$78,935	$79,593	$37,877	$34,477	$41,537	$39,383	$44,235	$71,837	$107,821	$165,805	$156,329	$103,640	$961,468
20	FIRM BILLS	$66.00	213	212	210	203	215	208	210	213	208	205	212	215	2,524
21	Sales: 1-300	1.5483	27,358	16,430	9,573	8,454	8,648	9,243	10,823	23,510	34,113	43,948	45,008	34,440	271,549
22	Sales: 301-15000	1.0762	20,925	37,319	8,543	7,424	12,968	10,541	12,654	19,864	38,354	78,266	67,506	33,568	347,933
23	Sales: Over 15000	0.8888	0	0	0	0	0	0	0	0	0	0	0	0	0
24	CLASS TOTAL (Mcf/month)		48,282	53,749	18,117	15,878	21,617	19,784	23,477	43,374	72,466	122,214	112,515	68,009	619,482
25	Gas Charge per Mcf		$4.58	$4.93	$4.93	$4.93	$5.30	$5.30	$5.30	$5.33	$5.33	$5.33	$4.89	$4.89	
26	Gas Costs		$221,196	$265,152	$89,373	$78,327	$114,547	$104,833	$124,403	$231,178	$386,232	$651,380	$550,494	$332,741	$3,149,856
27															
28	FIRM PUBLIC AUTHORITY (Rate G-1)		$219,639	$167,990	$136,710	$134,369	$134,663	$136,293	$152,710	$222,737	$294,190	$326,570	$341,395	$277,958	$2,545,225
29	FIRM BILLS	$66.00	1,504	1,513	1,483	1,490	1,493	1,496	1,504	1,502	1,507	1,516	1,503	1,507	18,018
30	Sales: 1-300	1.5483	72,573	39,287	22,476	21,359	21,453	23,643	31,614	73,414	114,686	124,978	134,401	105,739	785,623
31	Sales: 301-15000	1.0762	7,443	6,787	3,748	2,749	2,703	883	4,180	9,235	15,945	30,673	31,689	13,734	129,768
32	Sales: Over 15000	0.8888	0	0	0	0	0	0	0	0	0	0	0	0	0
33	CLASS TOTAL (Mcf/month)		80,016	46,074	26,223	24,109	24,156	24,526	35,794	82,649	130,630	155,651	166,090	119,473	915,391
34	Gas Charge per Mcf		$4.58	$4.93	$4.93	$4.93	$5.30	$5.30	$5.30	$5.33	$5.33	$5.33	$4.89	$4.89	
35	Gas Costs		$366,577	$227,292	$129,363	$118,931	$128,002	$129,963	$189,670	$440,503	$696,237	$829,592	$812,617	$584,536	$4,653,284
36															
37	INTERRUPTIBLE COMMERCIAL (G-2)		$2,079	$2,460	$1,097	$1,058	$1,067	$1,157	$1,082	$1,722	$2,487	$2,982	$3,345	$2,610	$23,149
38	INT BILLS	520.00	3	4	2	2	2	2	2	3	3	3	3	3	32
39	Sales: 1-15000	0.9557	543	398	59	19	29	122	44	170	970	1,488	1,868	1,099	6,811
40	Sales: Over 15000	0.7837	0	0	0	0	0	0	0	0	0	0	0	0	1
41	CLASS TOTAL (Mcf/month)		543	398	59	19	29	122	44	170	970	1,488	1,868	1,099	6,812
42	Gas Charge per Mcf		$3.48	$3.83	$3.83	$3.83	$4.20	$4.20	$4.20	$4.23	$4.23	$4.23	$3.79	$3.79	
43	Gas Costs		$1,891	$1,524	$227	$73	$120	$514	$186	$719	$4,105	$6,295	$7,086	$4,169	$26,911
44															

ATMOS ENERGY CORPORATION – KENTUCKY
BILL FREQUENCY WITH KNOWN & MEASURABLE ADJUSTMENTS
TEST YEAR ENDING MARCH 31 2026
CURRENT RATES

Line No.	Class of Customers	Rate	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Total Billing Units
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
45	INTERRUPTIBLE INDUSTRIAL (G-2)		$20,957	$18,096	$17,503	$9,867	$10,864	$13,500	$12,463	$15,884	$20,412	$21,700	$19,691	$22,166	$203,103
46	INT BILLS	520.00	6	6	6	5	5	6	6	6	5	8	8	6	73
47	Sales: 1-15000	0.9557	2,078	2,200	1,286	1,621	2,041	2,038	1,557	1,833	1,436	1,910	1,861	2,105	21,968
48	Sales: Over 15000	0.7837	20,225	16,426	16,784	7,296	8,056	10,760	10,023	14,052	20,977	20,051	17,548	21,736	183,934
49	CLASS TOTAL (Mcf/month)		22,304	18,627	18,070	8,916	10,097	12,798	11,580	15,885	22,413	21,961	19,409	23,841	205,902
50	Gas Charge per Mcf		$3.48	$3.83	$3.83	$3.83	$4.20	$4.20	$4.20	$4.23	$4.23	$4.23	$3.79	$3.79	
51	Gas Costs		$77,646	$71,399	$69,266	$34,178	$42,397	$53,737	$48,623	$67,191	$94,802	$92,892	$73,630	$90,445	$816,206
52															
53	TRANSPORTATION (T-4)		$666,931	$656,826	$672,783	$655,018	$762,573	$830,219	$861,572	$1,048,540	$875,384	$826,229	$729,283	$687,736	$9,273,095
54	TRANSPORTATION BILLS	$520.00	118	118	118	117	117	117	117	117	118	118	118	118	1,415
55	Trans Admin Fee		5,900	5,900	5,900	5,850	5,850	5,850	5,850	5,850	5,900	5,900	5,900	5,950	$70,600
56	EFM Fee		7,050	7,050	7,125	6,750	6,900	6,750	6,900	6,900	6,975	7,050	7,200	6,975	$83,625
57	Parking Fee		0	0	0	0	0	0	0	0	0	0	0	0	$0
58	Firm Transport: 1-300	1.5483	31,741	31,401	31,573	31,784	34,535	36,152	36,243	35,897	35,222	35,441	34,241	32,256	406,485
59	Firm Transport: 301-15000	1.0762	412,964	406,841	413,845	404,807	471,920	525,332	567,791	676,762	551,047	503,579	440,323	411,568	5,786,780
60	Firm Transport: Over 1500	0.8888	111,234	107,871	116,961	108,610	143,399	152,185	135,722	214,738	172,590	174,297	143,735	135,463	1,716,805
61	CLASS TOTAL (Mcf/month)		555,939	546,113	562,378	545,201	649,854	713,669	739,756	927,398	758,859	713,316	618,299	579,287	7,910,070
62															
63	ECONOMIC DEV RIDER (EDR)		-	-	-	-	-	-	-	-	-	-	-	-	-
64	Firm Transport: 1-300	1.161225	0	0	0	0	0	0	0	0	0	0	0	0	0
65	Firm Transport: 301-15000	0.8072	0	0	0	0	0	0	0	0	0	0	0	0	0
66	Firm Transport: Over 15000	0.6666	0	0	0	0	0	0	0	0	0	0	0	0	0
67	CLASS TOTAL (Mcf/month)		0	0	0	0	0	0	0	0	0	0	0	0	0
68															
69	TRANSPORTATION (T-3)		$656,524	$620,773	$552,212	$620,421	$714,361	$732,692	$735,838	$788,494	$713,431	$712,342	$669,432	$663,066	$8,179,586
70	TRANSPORTATION BILLS	520.00	71	71	71	71	71	71	71	71	71	71	71	71	852
71	Trans Admin Fee		3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	$42,000
72	EFM Fee		3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	3,975	$47,700
73	Parking Fee		0	0	0	0	0	0	0	0	0	0	0	0	$0
74	Interrupt Transport: 1-15000	0.9557	417,295	401,974	388,998	399,640	444,352	465,475	465,884	488,045	447,165	436,683	426,391	425,512	5,207,416
75	Interrupt Transport: Over 15000	0.7837	272,196	245,261	173,601	247,659	313,001	310,633	314,148	354,311	308,384	319,776	277,574	270,524	3,407,069
76	CLASS TOTAL (Mcf/month)		689,492	647,235	562,599	647,299	757,353	776,107	780,032	842,356	755,549	756,460	703,965	696,036	8,614,485
77															
78	SPECIAL CONTRACTS		$294,857	$274,116	$255,651	$224,506	$270,434	$240,831	$215,894	$256,669	$240,852	$258,976	$304,934	$280,519	$3,118,240
79	TRANSPORTATION BILLS	520.00	13	13	13	12	12	12	12	12	12	13	13	13	154
80	Trans Admin Fee		650	650	650	600	600	600	600	600	600	650	650	650	$7,500
81	EFM Fee		750	750	750	675	675	675	675	675	675	750	750	750	$8,550
82	Parking Fee		0	0	0	0	0	0	0	0	0	0	0	0	$0
83	Transported Volumes	Various	1,174,025	1,325,397	1,227,574	1,095,712	1,171,326	1,223,327	1,296,950	1,535,324	1,391,760	1,467,401	1,320,464	1,275,923	15,505,182
84	Charges for Transport Volumes		286,517	265,776	247,311	216,811	262,739	233,136	208,199	248,974	233,157	250,636	296,594	272,179	$3,022,030
85	CLASS TOTAL (Mcf/month)		1,174,025	1,325,397	1,227,574	1,095,712	1,171,326	1,223,327	1,296,950	1,535,324	1,391,760	1,467,401	1,320,464	1,275,923	15,505,182
86															
87	OTHER REVENUE														
88	Service Charges		$3,438	$3,844	$3,004	$3,387	$3,698	$4,212	$9,928	$8,550	$4,906	$5,587	$4,026	$4,332	$58,912
89	Late Payment Fees		$41,096	$30,594	$21,780	$16,033	$15,172	$15,548	$15,486	$18,793	$33,240	$47,958	$55,753	$56,008	$367,462
90															
91	TOTAL GROSS PROFIT		$8,475,463	$7,298,721	$6,531,878	$6,409,099	$6,657,754	$6,683,026	$7,063,480	$8,877,272	$10,175,893	$11,003,381	$11,274,397	$9,730,749	$100,181,115
92	Gas Costs		$6,982,219	$4,112,630	$2,020,054	$1,734,260	$1,895,724	$1,919,919	$3,099,922	$8,220,795	$13,532,728	$16,482,302	$16,228,082	$11,412,264	$87,640,898
93	TOTAL REVENUE		$15,457,682	$11,411,351	$8,551,932	$8,143,359	$8,553,478	$8,602,946	$10,163,402	$17,098,067	$23,708,621	$27,485,683	$27,502,479	$21,143,013	$187,822,013

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS

RATE OF RETURN

INDEX TO THE DIRECT TESTIMONY
OF DYLAN W. D'ASCENDIS, WITNESS FOR
ATMOS ENERGY CORPORATION

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EXHIBITS

Exhibit DWD-1 – Summary of Cost of Capital and Overall Rate of Return and Financial Profile and Capital Structures of the Proxy Group

Exhibit DWD-2 – Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model

Exhibit DWD-3 – Indicated Common Equity Cost Rate Using the Risk Premium Model

Exhibit DWD-4 – Indicated Common Equity Cost Rate Using the Capital Asset Pricing Model

Exhibit DWD-5 – Basis of Selection for the Non-Price Regulated Companies Comparable in Total Risk to the Proxy Groups

Exhibit DWD-6 – Cost of Common Equity Models Applied to the Non-Price Regulated Proxy Groups

Exhibit DWD-7 – Estimated Market Capitalization for the Company and the Proxy Group

Exhibit DWD-8 – Flotation Cost Recovery Hypothetical Example
Exhibit DWD-9 – Derivation of the Flotation Cost Adjustment
Exhibit DWD-10 – Rate Mechanisms for the Utility Proxy Group

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, NJ 08054.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Partner at ScottMadden, Inc.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have offered expert testimony on behalf of investor-owned utilities in over 40 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the National Energy Regulator in Canada, the Alberta Utility Commission, one American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization-weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present evidence and provide a recommendation regarding Atmos Energy Corporation's Kentucky operations' ("Atmos Energy" or the "Company") return on common equity ("ROE") to be used for ratemaking purposes in this proceeding.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR DIRECT TESTIMONY?

A. Yes, I have. I prepared Exhibits DWD-1 through DWD-10, which were prepared by me or under my direct supervision.

Q. WHAT IS YOUR RECOMMENDED ROE FOR ATMOS ENERGY?

A. I recommend that the Kentucky Public Service Commission ("KY PSC" or the "Commission") authorize Atmos Energy the opportunity to earn an ROE of 10.95% on its jurisdictional rate base. The ratemaking capital structure and debt cost rates

are sponsored by Company Witness Joe T. Christian. The overall rate of return is summarized on page 1 of Exhibit DWD-1 and in Table 1 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	38.93%	4.11%	1.60%
Short-Term Debt	0.19%	17.14%	0.03%
Common Equity	60.88%	10.95%	6.67%
Total	100.00%		8.30%

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR RECOMMENDED COMMON EQUITY COST RATE.

A. My recommended common equity cost rate of 10.95% is summarized on page 2 of Exhibit DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to Atmos Energy. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the Company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from the application of several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a proxy group of six natural gas distribution utilities ("Utility Proxy

[1] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").
[2] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*").

Group") whose selection criteria will be discussed below. In addition, I applied these same models to a proxy group of 53 domestic, non-price regulated companies comparable in total risk to the Utility Proxy Group ("Non-Price Regulated Proxy Group"). The results derived from each are as follows:

Table 2: Summary of Common Equity Cost Rates

Discounted Cash Flow Model	9.93%
Risk Premium Model	10.80%
Capital Asset Pricing Model	11.36%
Market Models Applied to Comparable Risk, Non-Price Regulated Companies	12.05%
Indicated Range of Common Equity Cost Rates Before Adjustments for Company-Specific Risk	9.93% - 12.05%
Size Adjustment	0.05%
Credit Risk Adjustment	-0.04%
Flotation Cost Adjustment	0.06%
Indicated Range of Common Equity Cost Rates after Adjustment	10.12% – 12.12%
Recommended Cost of Common Equity	10.95%

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 9.93% and 12.05%, before any Company-specific adjustments.[3]

To reflect Atmos Energy's specific risks, I then adjusted the indicated common equity cost rate model results to reflect the Company's smaller relative size and higher bond rating, as compared to the Utility Proxy Group. I also adjusted the indicated range of common equity cost rate upward to reflect flotation costs.

[3] The indicated range of ROEs applicable to the Utility Proxy Group excluding the Predictive Risk Premium Model ("PRPM") is 9.93% to 11.97%.

These adjustments resulted in a Company-specific indicated range of common equity cost rates between 10.00% and 12.12%. From the Company-specific range of ROEs between 10.00% and 12.12%, I recommend the Commission adopt an ROE of 10.95% for ratemaking purposes in this case.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. The remainder of my Direct Testimony is organized as follows:

- Section III – Provides a summary of financial theory and regulatory principles pertinent to the development of the cost of common equity;
- Section IV – Explains my selection of the Utility Proxy Group used to develop my analytical results;
- Section V – Describes the analyses on which my recommendation is based;
- Section VI – Summarizes my common equity cost rate before adjustments to reflect Company-specific factors;
- Section VII – Explains my adjustments to my common equity cost rate to reflect Company-specific factors;
- Section VIII – Presents other considerations relevant to the cost of common equity; and
- Section IX – Presents my conclusions.

III. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE OF 10.95%?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, *i.e.*, the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the

enterprise, so as to maintain its credit and to attract capital.[4]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this proceeding, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure the Company's financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, i.e., for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. That is, utility holding companies that own many utility operating companies or are comprised of separate divisions, have choices as to where they will invest their capital within their operating footprint. Therefore, the opportunity cost concept applies regardless of the source of the funding, public funding or corporate funding.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That

[4] *Hope*, 320 U.S. 591 (1944), at 603.

is, the regulated subsidiary must compete for capital with all the parent company's affiliates, across divisions, and with other, similarly situated utility companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective as measured by their combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (i.e., business risk) and financing (i.e., financial risk) of the Company's utility operations on a stand-alone basis.

Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (i.e., rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of long-term debt and equity) is based on the economic principle of "opportunity costs." Investing in

any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

The cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities. However, the cost of equity is not directly observable and must be estimated based on market data and various financial models. Because the cost of equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS GUARENTEED?

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the ratemaking process should provide the utility a reasonable opportunity to recover its return of, and return on, its reasonably incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (e.g., management performance, operating and maintenance expenses, etc.), there are several factors beyond a utility's control that

affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag.

A. Business Risk

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.[5]

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, pipeline safety requirements, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, and the like, all of which have a direct bearing on earnings.

Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. When determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other

[5] As will be discussed later in this testimony, another definition of total risk is systematic risk plus unsystematic risk.

similarly situated utility companies (i.e., the Utility Proxy Group). To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate and reliable service (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. This means that utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering a fair return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT IN DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (i.e., failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors demand higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (I.E., INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (i.e., total risk) faced by bond investors.[6] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

[6] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., within the A category, an S&P rating can by at A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, e.g., within the A category, a Moody's rating can be A1, A2 and A3.

IV. ATMOS ENERGY'S OPERATIONS AND THE UTILITY PROXY GROUP

Q. ARE YOU FAMILIAR WITH ATMOS ENERGY'S OPERATIONS?

A. Yes. Atmos Energy's operations serve approximately 185,000 customers in Kentucky.[7] Atmos Energy's gas operations are not publicly-traded as they comprise an operating division of Atmos Energy Corporation ("ATO"), which operates in eight states[8] and serves approximately 3.5 million gas customers[9] and is publicly-traded under symbol ATO.

Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN ESTIMATING THE ROE FOR THE COMPANY?

A. Because the Company is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.[10]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore

[7] Atmos Energy Corporation, 2023 SEC Form 10-K, at 4.
[8] Atmos Energy Corporation, 2023 SEC Form 10-K, at 4, In addition to Kentucky, ATO also serves customers in Texas, Louisiana, Mississippi, Virginia, Colorado, Kansas, and Tennessee.
[9] Atmos Energy Corporation, 2023 SEC Form 10-K, at 4.
[10] The development of the Non-Price Regulated Proxy Group is explained in more detail in Section V.

is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses that necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group's indicated results.

Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE UTILITY PROXY GROUP.

A. The companies selected for the Utility Proxy Group met the following criteria:

(i) They were included in the Natural Gas Utility Group of *Value Line's Standard Edition* (*Value Line*) (May 24, 2024);

(ii) They have 60% or greater of fiscal year 2023 total operating income derived from, or 60% or greater of fiscal year 2023 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another);

(iv) They have not cut or omitted their common dividends during the five years ended 2023 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Beta coefficients ("beta");

(vi) They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and

(vii) They have *Value Line*, Zacks, S&P Capital IQ, or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections.

The following six companies met these criteria:

Table 3: Gas Utility Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Spire Inc.	SR

V. COMMON EQUITY COST RATE MODELS

Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET BASED?

A. Yes. While a public utility operates a regulated business within the states in which it operates, it still must compete for equity in capital markets along with all other companies of comparable risk, which includes non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies of comparable risk, they will choose a company providing a higher return over a company providing a lower return.

Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET BASED?

A. Yes. The DCF model uses market prices in developing the model's dividend yield component. The RPM uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk. In addition, betas (β), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The CAPM is market-based for many of the same reasons that the RPM is market-based (i.e., the use of expected bond yields and betas). Selection criteria for comparable risk non-price regulated companies

are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANY'S ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I apply to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (i.e., the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

A. <u>Discounted Cash Flow Model</u>

Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined

by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; *i.e.*, the total common equity return rate expected by investors.

$$K_e = (D_0 (1+g))/P + g$$

where:

K_e = the required Return on Common Equity;

D_0 = the annualized Dividend Per Share;

P = the current stock price; and

g = the growth rate.

Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?

A. I used the single-stage constant growth DCF model in my analyses.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of July 31, 2024, divided by the average closing market price for the 60 trading days ended July 31, 2024.[11]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (*e.g.* quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

[11] *See*, column 1, page 1 of Exhibit DWD-2.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Exhibit DWD-2 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, S&P Capital IQ, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' ability to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. The results of applying the DCF model to the Utility Proxy Groups are shown on page 1 of Exhibit DWD-2 and in Table 4 below:

Table 4: DCF Model Results for the Utility Proxy Group

Mean	9.95%
Median	9.91%
Average of Mean and Median	9.93%

In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and median results of the DCF, specifically 9.93%. This approach takes into consideration all proxy company results while mitigating high and low side outliers of those results.

B. The Risk Premium Model

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost

rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings in the event of liquidation.

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, (2) an equity risk premium based on the S&P Utilities Index, and (3) an equity risk premium based on authorized ROEs for natural gas distribution utilities.

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELDS OF 5.59% APPLICABLE TO THE UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the fourth calendar quarter of 2025, and *Blue Chip Financial Forecast's ("Blue Chip")* long-term projections for 2026 to 2030, and 2031 to 2035. As shown on line 1, page 1 of Exhibit DWD-3, the average expected yield on Moody's Aaa-rated corporate bonds is 5.09%. In order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield, I made an upward adjustment of 0.50%, which represents a recent

spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[12] Adding that recent 0.50% spread to the expected Aaa-rated corporate bond yield of 5.09% results in an expected A2-rated public utility bond yield of 5.59%. Since the Utility Proxy Group's average Moody's long-term issuer rating is A2, no further adjustment is needed.

Table 5: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[13]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip*)	5.09%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.50%
Prospective Bond Yield Applicable to the Utility Proxy Group	5.59%

a. The Beta-Derived Risk Premium

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 8, on page 6 of Exhibit DWD-3. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, a *Value Line*-based equity risk premium, and a combined *Value Line*, Bloomberg, and S&P Capital IQ-based equity risk premium. Each of these are described below.

[12] As shown on line 2 of page 1 of Exhibit DWD-3 and explained in note 2, page 1 of Exhibit DWD-3.

[13] As shown on page 1 of Exhibit DWD-3.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2023. The use of holding period returns over a very long period of time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, i.e., a company expected to operate in perpetuity.

The long-term arithmetic mean monthly total return rate on large company common stocks was 11.91% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 5.95% from 1928 to 2023. As shown on line 1 of page 6 of Exhibit DWD-3, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.96%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa-rated corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in Kroll's Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2023 ("SBBI - 2023"). The use of the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns because the geometric mean relates the

change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 6.98% shown on line 2, page 6 of Exhibit DWD-3, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bond yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

where:

RP = the market equity risk premium;

α = the regression intercept coefficient;

β = the regression slope coefficient; and

$R_{Aaa/Aa}$ = the Moody's Aaa/Aa rated corporate bond yield.

Q. PLEASE EXPLAIN THE DERIVATION OF THE PREDICTIVE RISK PREMIUM MODEL ("PRPM") EQUITY RISK PREMIUM.

A. The PRPM, published in the *Journal of Regulatory Economics* and *The Electricity Journal*,[14] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility ("ARCH")".[15] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that the volatility in prices and returns clusters over time, and is therefore highly predictable, and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk / return relationship directly, as the predicted equity risk premium is generated by the prediction of volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on the evaluation of the results of that behavior (i.e., the variance of historical equity risk premiums).

The inputs to the model are the historical returns on large company stocks minus the historical monthly yield on Moody's Aaa/Aa-rated corporate bonds from January 1928 through July 2024. Using a generalized form of ARCH, known as GARCH, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series and a

[14] Autoregressive conditional heteroscedasticity. *See*, "A New Approach for Estimating the Equity Risk Premium for Public Utilities", Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, *The Journal of Regulatory Economics* (December 2011), 40:261-278 and "Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity", Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, *The Electricity Journal* (May 2013), 84-89.

[15] www.nobelprize.org.

GARCH coefficient. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing, it produces the predicted annual equity risk premium. The resulting PRPM predicted a market equity risk premium of 8.11%.[16]

Q. IS THE PRPM SUPPORTED BY ACADEMIC LITERATURE?

A. Yes, it is. The PRPM is based on the research of Dr. Robert F. Engle, dating back to the early 1980s. Dr. Engle discovered that the volatility of market prices, returns, and risk premiums clusters over time, making prices, returns, and risk premiums highly predictable. In 2003, he shared the Nobel Prize in Economics for this work, characterized as "methods of analyzing economic time series with time-varying volatility ("ARCH").[17] Dr. Engle[18] noted that relative to volatility, "the standard tools have become the ARCH/GARCH[19] models." Hence, the methodology is not new.

In addition, the GARCH methodology has been well tested by academia since Engle's, *et al*. research was originally published in 1982, 40 years ago. I use the well-established GARCH methodology to estimate the PRPM model using a standard commercial and relatively inexpensive statistical package, Eviews,©[20] to develop a means by which to estimate a predicted equity risk premium which, when added to a bond yield, results in a cost of common equity.

16 Shown on line 3, page 6 of Exhibit DWD-3.

17 www.nobelprize.org.

18 Robert Engle, "GARCH 101: The Use of ARCH/GARCH Models in Applied Econometrics", *Journal of Economic Perspectives*, Volume 15, No. 4, Fall 2001, at 157-168.

19 Autoregressive Conditional Heteroskedasticity/Generalized Autoregressive Conditional Heteroskedasticity.

20 In addition to Eviews,® the GARCH methodology can be applied and the PRPM derived using other standard statistical software packages such as SAS, RATS, S-Plus and JMulti, which are not cost-prohibitive. The software that I used in this proceeding, Eviews,® currently costs $600 - $700 for a single user commercial license. In addition, JMulti is a free downloadable software with GARCH estimation applications.

Also, the PRPM is in the public domain, having been published six times in academically peer-reviewed journals: *Journal of Economics and Business* (June 2011 and April 2015),[21] *The Journal of Regulatory Economics* (December 2011),[22] *The Electricity Journal* (May 2013 and March 2020),[23] and *Energy Policy* (April 2019).[24] Notably, none of these articles have been rebutted in the academic literature. Finally, the PRPM has also been presented to a number of utility industry/regulatory/academic groups including the following: The Edison Electric Institute Cost of Capital Working Group; The NARUC Staff Subcommittee on Accounting and Finance; The National Association of Electric Companies Finance/Accounting/Taxation and Rates and Regulations Committees; the NARUC Electric Committee; The Wall Street Utility Group; the Indiana Utility Regulatory Commission Cost of Capital Task Force; the Financial Research Institute of the University of Missouri Hot Topic Hotline Webinar; and the Center for Research and Regulated Industries Annual Eastern Conference on two occasions.

[21] Eugene A. Pilotte and Richard A. Michelfelder, "Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing", *Journal of Economics and Business*, June 2011, 582-604. and Richard A. Michelfelder, "Empirical Analysis of the Generalized Consumption Asset Pricing Model: Estimating the Cost of Capital", *Journal of Economics and Business*, April 2015, 37-50.

[22] Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, "New Approach to Estimating the Equity Risk Premium for Public Utilities", *The Journal of Regulatory Economics*, December 2011, at 40:261-278.

[23] Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, "Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity", *The Electricity Journal*, April 2013, at 84-89; and Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, "Decoupling, Risk Impacts and the Cost of Capital", *The Electricity Journal*, January 2020.

[24] Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, "Decoupling Impact and Public Utility Conservation Investment", *Energy Policy*, April 2019, 311-319.

Q. HAS THE PRPM BEEN IMPLICITLY ACCEPTED BY OTHER REGULATORY COMMISSIONS?

A. Yes, in Docket No. 2017-292-WS, the Public Service Commission of South Carolina ("PSC SC") accepted Blue Granite Water Company's entire requested ROE, which included the PRPM. The relevant portion states:

> The Commission finds Mr. D'Ascendis' arguments persuasive. He provided more indicia of market returns, by using more analytical methods and proxy group calculations. Mr. D'Ascendis' use of analysts' estimates for his DCF analysis is supported by consensus, as is his use of the arithmetic mean. The Commission also finds that Mr. D'Ascendis' non-price regulated proxy group more accurately reflects the total risk faced [by] price regulated utilities and CWS. Furthermore, there is no dispute that CWS is significantly smaller than its proxy group counterparts, and, therefore, it may present a higher risk. An appropriate ROE for CWS is 10.45% to 10.95%. The Company used an ROE of 10.5% in computing its Application, a return on the low end of Mr. D'Ascendis' range, and the Commission finds that ROE is supported by the evidence.[25]

In addition, in Docket No. W-354, Subs 363, 364 and 365, the State of North Carolina Utilities Commission ("NCUC") approved my RPM and CAPM analyses, which used PRPM analyses as presented in this proceeding. The relevant portion of the order states:

> In doing so the Commission finds that the DCF (8.81%), Risk Premium (10.00%) and CAPM (9.29%) model results provided by witness D'Ascendis, as updated to use current rates in D'Ascendis Late-Filed Exhibit No. 1, as well as the risk premium (9.57%) analysis of witness Hinton, are credible, probative, and are entitled to substantial weight as set forth below.[26]

Q. HAS THE COMMISSION REJECTED THE PRPM PREVIOUSLY?

A. Yes, it has. In Case No. 2021-00214 concerning the Company, the Commission stated:

[25] PSC SC Docket No. 2017-292-WS - Order No. 2018-345, at 14. (May 17, 2018)

[26] NCUC Docket No. W-354, Sub 363, 364, 365, *Order Granting Partial Rate Increase and Requiring Customer Notice*, at PDF 72 (March 31, 2020).

> Even though the Commission supports the use and presentation of multiple modelling approaches, the Commission finds that Atmos Kentucky's use of the Predictive Risk Premium Model (PRPM) should be rejected. Though the PRPM model has been published and presented in multiple forums, it has been rejected by this Commission and only been addressed by three other regulatory jurisdictions thus far and is not universally accepted.

Similarly, in Case No. 2022-00432 concerning Bluegrass Water Utility Operating Company, LLC, the Commission stated:

> Even though the Commission supports the use and presentation of multiple modelling approaches, the Commission continues to reject the use of the PRPM model to estimate risk premium. The PRPM model has been only been addressed by three other regulatory commissions and is not universally accepted.

Q. DO YOU HAVE A RESPONSE TO THE COMMISSION'S STATEMENTS?

A. Yes, I do. I appreciate the Commission's openness to considering multiple models in its determination of ROEs for the utilities they regulate, but I respectfully disagree with their exclusion of the PRPM in Case No. 2021-00214 and Case No. 2022-00432. As noted above, the theory supporting the model is based on the Nobel Prize winning work of Engle, and the model itself has been published six times in four separate peer-reviewed academic journals, which indicates that it has been thoroughly vetted by the academic community. This, in addition to the fact that the model has not been rebutted in the academic literature in the over ten years since it has been presented should speak to the model's soundness.

Regarding the amount of times the model has been addressed in final orders; while it is true that a number regulatory commissions have addressed the PRPM in their final orders, the model has been presented in over 100 regulatory proceedings in approximately 40 U.S. regulatory jurisdictions and the Alberta Utilities

Commission in Canada. This would indicate that while maybe not universally accepted, the model is widely disseminated across the U.S. regulatory landscape.

In view of the above, the soundness of the model, as evidenced in the underlying theory and the academic vetting of the PRPM, and the wide dissemination of the model in the U.S. regulatory landscape should lead the Commission reconsider the PRPM in its determination regarding the ROE for Atmos Energy in this proceeding.

Q. HAVE YOU APPLIED THE PRPM IN THE SAME MANNER IN THIS PROCEEDING AS YOU DID IN CASE NOS. 2021-00214 AND 2022-00432?

A. In part. In my Direct Testimony in this proceeding, I have not relied on the PRPM results of the individual companies in the Utility Proxy Group. However, I continue to rely on the PRPM in my estimation of the equity risk premium used in my RPM and CAPM analyses.

Q. DOES INCLUDING THE PRPM MATERIALLY AFFECT YOUR INDICATED MODEL RESULTS?

A. No, it does not. While I respectfully disagree with the Commission's previous findings, I have presented my ROE model results including and excluding the PRPM for the Commission's convenience. Viewing the results, the difference in the RPM, CAPM and Non-Price Regulated Proxy Group including and excluding the PRPM are 0.05%, 0.08%, and 0.08%, respectively. These differences would not materially change my recommended ROE in this instance.

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* SUMMARY & INDEX DATA FOR YOUR RPM ANALYSIS.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 6 of Exhibit DWD-3. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three-to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended August 2, 2024, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line* (Standard Edition).[27]

The average median expected price appreciation is 47.00%, which translates to a 10.11% annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 2.13%, equates to a forecasted annual total return rate on the market of 12.24%. The forecasted Moody's Aaa-rated corporate bond yield of 5.09% is deducted from the total market return of 12.24%, resulting in an equity risk premium of 7.15%, as shown on line 4, page 6 of Exhibit DWD-3.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.

A. Using data from *Value Line*, Bloomberg, and S&P Capital IQ, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 15.42%. Subtracting the prospective yield on

[27] As explained in detail in note 1, page 2 of Exhibit DWD-4.

Moody's Aaa-rated corporate bonds of 5.09% results in a 10.33% projected equity risk premium as shown on page 6, line 5 of Exhibit DWD-3.

Q. WHAT IS YOUR CONCLUSION OF A BETA-DRIVEN EQUITY RISK PERMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to all five equity risk premiums based on each source – historical, *Value Line*, and Bloomberg – in arriving at a 7.70% equity risk premium.

Table 6: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[28]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa-Rated Corporate Bond Yields (1928 – 2023)	5.96%
Regression Analysis on Historical Data	6.98%
PRPM Analysis on Historical Data	8.11%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	7.15%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Projected Aaa Corporate Bond Yields	10.33%
Average	7.70%

After calculating the average market equity risk premium of 7.70%, I adjusted it by beta to account for the risk of the Utility Proxy Group. As discussed below, beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Exhibit DWD-4, the average of the mean and median beta for the Utility Proxy Group is 0.79. Multiplying beta by the market equity risk premium of 7.70% results in a 6.08% beta-adjusted equity risk premium.

[28] As shown on page 6 of Exhibit DWD-3.

b. The S&P Utility Index-Derived Risk Premium

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A2-RATE PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and one equity risk premium based on the expected returns of the S&P Utilities Index, using *Value Line*, Bloomberg data, and S&P Capital IQ. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.45% and monthly Moody's A2-rated public utility bond yields of 6.43% from 1928 to 2023, to arrive at an equity risk premium of 4.02%.[29] I then used the same historical data to derive an equity risk premium of 4.86% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to July 2024 to arrive at a PRPM-derived equity risk premium of 4.98% for the S&P Utility Index.

I then derived an expected total return on the S&P Utilities Index of 10.67% using data from *Value Line*, Bloomberg, and S&P Capital IQ, and subtracted the prospective Moody's A2-rated public utility bond yield of 5.59%.[30] This resulted in equity risk premium of 5.08%. As with the market equity risk premiums, I averaged the four risk premium based to arrive at my utility-specific equity risk premium of 4.73%.

[29] As shown on line 1, page 9 of Exhibit DWD-3.
[30] Derived on line 3, page 1 of Exhibit DWD-3.

Table 7: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[31]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2023)	4.02%
Regression Analysis on Historical Data	4.86%
PRPM Analysis on Historical Data	4.98%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P Utilities Index less Projected A2 Utility Bond Yields	5.08%
Average	4.73%

c. Authorized Return-Derived Equity Risk Premium

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 4.82% BASED ON AUTHORIZED ROEs FOR NATURAL GAS DISTRIBUTION UTILITIES?

A. The equity risk premium of 4.82% shown on page 10 of Exhibit DWD-3 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds and contains the graphical results of a regression analysis of 836 rate cases for natural gas distribution utilities which were fully litigated during the period from January 1, 1980 through July 31, 2024. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[32] I used the regression results to estimate the

[31] As shown on page 9 of Exhibit DWD-3.

[32] *See, e.g.,* Robert S. Harris and Felicia C. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts", Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity", Financial Management, Spring 1985, at 33-45.

equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the expected A2-rated utility bond yield of 5.59%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.82%.

Q. WHAT IS YOUR CONCLUSION OF EQUITY RISK PREMIUMS FOR USE IN YOUR TOTAL MARKET APPROACH RPM?

A. The equity risk premiums I applied to the Utility Proxy Group is 5.21% which is the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premium.

Table 8: Summary of Conclusions for the Equity Risk Premium for the Utility Proxy Group[33]

Beta-Adjusted Equity Risk Premium	6.08%
S&P Utilities Index Equity Risk Premium	4.73%
Authorized ROE Equity Risk Premium	4.82%
Average	5.21%

Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 5 page 1 of Exhibit DWD-3, and shown on Table 9, below, I calculated a common equity cost rate of 10.80% for the Utility Proxy Group based on the total market approach RPM.

Table 9: Summary of the Total Market Return Risk Premium Model[34]

Prospective Moody's Utility Bond Yield Applicable to the Utility Proxy Group	5.59%
Prospective Equity Risk Premium	5.21%
Indicated Cost of Common Equity	10.80%

[33] As shown on page 5 of Exhibit DWD-3.
[34] As shown on page 1 of Exhibit DWD-3.

C. The Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all other risk (i.e., all non-market or unsystematic risk) can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors require compensation only for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where:
R_s = Return rate on the common stock
R_f = Risk-free rate of return
R_m = Return rate on the market as a whole
β = Adjusted beta (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical Security

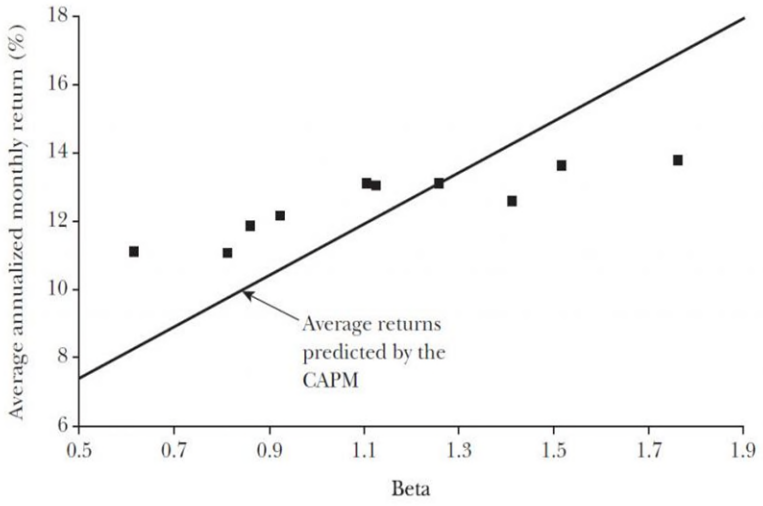
Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[35] The ECAPM reflects this empirical reality.

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM. WHY IS THE USE OF ECAPM APPROPRIATE IN DETERMINING THE ROE FOR THE COMPANY?

A. The ECAPM is a well-established model that has been relied on in both academic and regulatory settings. Fama & French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[36]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

[35] Roger A. Morin, Modern Regulatory Finance (Public Utility Reports, Inc., 2021), at page 223 ("Morin").

[36] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004 at 33 ("Fama & French").

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[37]

* * *

> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x\,\beta(R_M - R_F) + (1-x)\,\beta(R_M - R_F)$$

> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$[38]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[39]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[40]

Clearly, the justification from Morin and Fama & French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM.

In view of theory and practical research, I have applied both the traditional CAPM

[37] Morin, at 207.
[38] Morin, at 221.
[39] Fama & French, at 32.
[40] Fama & French, at 33.

and the ECAPM to the companies in the Utility Proxy Groups and averaged the results.

Q. WHAT BETAS DID YOU USE IN YOUR CAPM ANALYSIS?

A. With respect to beta, I considered two methods of calculation: (1) the average of the betas of the respective proxy group companies as reported by Bloomberg, and (2) the average of the betas of the respective proxy group companies as reported by *Value Line*. While both of those services adjust their calculated (or "raw") betas to reflect the tendency of beta to regress to the market mean of 1.00, *Value Line* calculates beta over a five-year period, while Bloomberg's calculation is based on two years of data.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Exhibit DWD-4, the risk-free rate adopted for applications of the CAPM is 4.36%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the fourth calendar quarter of 2025, and long-term projections for the years 2026 to 2030 and 2031 to 2035.

Q. WHY DO YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN YOUR ANALYSES?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (i.e., cost of capital) will be applied.

In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSES.

A. The basis of the market risk premium is explained in detail in note 1 on page 2 of Exhibit DWD-4. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, one *Value Line* data-based market risk premium, and one *Value Line*, Bloomberg, and S&P Capital IQ data-based market risk premium.

The long-term income return on U.S. Government Securities of 4.99% was deducted from the monthly historical total market return of 12.16%, which results in an historical market equity risk premium of 7.17%.[41] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government Securities. That regression analysis yielded a market equity risk premium of 7.99%. The PRPM market equity risk premium is 9.04% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through July 2024.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 4.36%, discussed above, from the *Value Line* projected total annual market return of 12.24%, resulting in a forecasted total market equity risk premium of 7.88%.

The S&P 500 projected market equity risk premium using *Value Line*, Bloomberg and S&P Capital IQ data is derived by subtracting the projected risk-

[41] Sources: SBBI - 2023, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21); Bloomberg Professional.

free rate of 4.36% from the projected total return of the S&P 500 of 15.42%. The resulting market equity risk premium is 11.06%.

These five market risk premiums, when averaged, result in an average total market equity risk premium of 8.63%.

Table 10: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[42]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2023)	7.17%
Regression Analysis on Historical Data	7.99%
PRPM Analysis on Historical Data	9.04%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	7.88%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from for the S&P 500 less Projected 30-Year Treasury Bond Yields	11.06%
Average	8.63%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Exhibit DWD-4, the mean result of my CAPM/ECAPM analyses is 11.35%, the median is 11.37%, and the average of the two is 11.36%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 11.36%.

[42] As shown on page 2 of Exhibit DWD-4.

D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM

Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. Although, I am not an attorney, my interpretation of the *Hope* and *Bluefield* cases is that they did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the utility proxy groups being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in proxy groups which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. To select proxy groups of domestic, non-price regulated companies similar in total risk to the Utility Proxy Groups, I relied on betas and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (i.e., five years). As shown on Exhibit DWD-5, these selection criteria resulted in a proxy group of 53 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, i.e., not utilities;

(iii) Their unadjusted betas must lie within plus or minus two standard deviations of the average unadjusted beta of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Betas measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, THE RPM, AND THE CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums

Page 2 of Exhibit DWD-6 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the

constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group, is 11.29%.

Page 3 through 5 of Exhibit DWD-6 contain the data and calculations that support the 12.53% RPM common equity cost rates. As shown on line 1, page 3 of Exhibit DWD-6, the consensus prospective yield on Moody's Baa2-rated corporate bonds for the six quarters ending in the fourth quarter of 2025, and for the years 2026 to 2030 and 2031 to 2035, is 5.96%.[43] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of A3, it is necessary to take a two-thirds downward adjustment (0.21%) of the 0.32% spread between A and Baa2 corporate bond to reach an adjusted prospect bond yield of 5.75%.

When beta-adjusted risk premium of 6.78%[44] relative to the Non-Price Regulated Proxy Group is added to the prospective A3-rated corporate bond yield of 5.75%, the indicated RPM common equity cost rate is 12.53%.

Page 6 of Exhibit DWD-6 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rates of 12.11%.

Q. WHAT IS THE COST RATE OF COMMON EQUITY BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Exhibit DWD-6, the results of the common equity models applied to the Non-Price Regulated Proxy Group – which is comparable in total risk to the Utility Proxy Group – are as follows:

[43] *Blue Chip Financial Forecasts*, August 1, 2024 at 2 and May 31, 2024, 14.
[44] Derived on page 5 of Exhibit DWD-6.

Table 11: Summary of Model Results Applied to the Non-Price Regulated Proxy Group[45]

Discounted Cash Flow Model	11.29%
Risk Premium Model	12.53%
Capital Asset Pricing Model	12.11%
Mean	11.98%
Median	12.11%
Average of Mean and Median	12.05%

The average of the mean and median of these models is 12.05%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

VI. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

Q. WHAT ARE THE INDICATED COMMON EQUITY COST RATES BEFORE ADJUSTMENTS?

A. The range of indicated ROEs produced from my analysis is from 9.93% (DCF model) and 12.05% (Non-Price Regulated Market Models), which is applicable to the Utility Proxy Group as shown on Exhibit DWD-1, page 2. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent. In view of these results, I recommend a range of ROEs applicable to the Utility Proxy Groups between 9.93% and

[45] As shown on page 1 of Exhibit DWD-6.

12.05%.

As will be discussed below, Atmos Energy has unique company-specific risk factors relative to the Utility Proxy Group. Because of this, the indicated range of model results based on the Utility Proxy Group must be adjusted to reflect Atmos Energy's relative risk.

VII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

Q. DID THE COMMISSION REJECT RELATIVE RISK ADJUSTMENTS TO THE ROE IN CASE NO. 2021-00214 AND CASE NO. 2022-00432?

A. Yes, it did. In Case No. 2021-00214 concerning the Company the Commission stated:

> The Commission reiterates that it continues to reject use of flotation cost adjustments, financial risk adjustments, and size adjustments in the ROE analyses.

In Case No. 2022-00432 the Commission stated:

> Additionally, the Commission further reiterates that it continues to reject the use of flotation cost adjustments, financial risk adjustments and explicit size adjustments in the ROE analyses considering a business risk or size adjustment has not be approved in the past and the Commission agrees with the Attorney General on that matter.

Q. DO YOU HAVE A RESPONSE TO THE COMMISSION'S STATEMENT?

A. Yes, I do. I respectfully disagree with the Commission's rejection of Company-specific risk adjustments as stated in their Final Orders in Case Nos. 2021-00214 and in Case No. 2022-00432. As will be explained in detail below, the adjustments applied to the indicated range of ROEs applicable to the Utility Proxy Group to reflect Atmos Energy's specific risks are academically and empirically supported.

Q. DOES THE COMMISSION IMPLICITLY CONSIDER A COMPANY'S UNIQUE RISKS IN DETERMINING THEIR ROE?

A. Yes, it does. In Case No. 2021-00214 the Commission stated:

> An ROE of 9.23 percent is lower than recent Commission awards for gas utilities, but those awards were tied to stay-out clauses **for a utility that is significantly smaller**, rural and had not requested a rate increase for over ten years. Additionally, in deciding upon the approved ROE, the Commission is also balancing the recent destruction due to the devastating tornadoes and customer bill impact during the region's recovery, **as well as the still high equity percentage**. (emphasis added)

While this Commission does not specifically assign basis points to a company's unique risks as compared to a proxy group, they are clearly considered in the above passage.

A. <u>Size Adjustment</u>

Q. DOES ATMOS ENERGY'S SMALLER SIZE RELATIVE TO THE UTILITY PROXY GROUP COMPANIES INCREASE ITS BUSINESS RISK?

A. Yes. Atmos Energy's smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

Investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," Kroll states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[46]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 38, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[47]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[48] Eugene Brigham, a well-known authority, states:

[46] Kroll, Cost of Capital Navigator: U.S. Cost of Capital Module, Size as a Predictor of Returns, at 1.

[47] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Volume 18, Number 3, Summer 2004, at 25-43.

[48] Brealey, Richard A. and Myers, Stewart C., Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms**. (emphasis added)[49]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of Atmos Energy, including its small size, which is justified and supported above by evidence in the financial literature.

Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO ATMOS ENERGY'S SMALL SIZE RELATIVE TO THE UTILITY PROXY GROUP?

A. Yes. Atmos Energy has greater relative risk than the average utility in the Utility Proxy Group because of its smaller size compared with the utilities in that group, as measured by an estimated market capitalization of common equity for Atmos Energy.

[49] Brigham, Eugene F., Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

Table 12: Size as Measured by Market Capitalization for Atmos Energy and the Utility Proxy Group

	Market Capitalization* ($ Millions)	Times Greater than The Company
Atmos Energy Kentucky Operations	$606.404	
Utility Proxy Group	$4,249.683	7.0x
*From page 1 of Exhibit DWD-7.		

Atmos Energy's estimated market capitalization was $606.404 million as of July 31, 2024,[50] compared with the market capitalization of the median company in the Utility Proxy Group of $4.249 billion as of July 31, 2024. The average company in the Utility Proxy Group has a market capitalization 7.0 times the size of Atmos Energy's estimated market capitalization.

As a result, it is necessary to upwardly adjust the range of indicated common equity cost rates to reflect Atmos Energy's greater risk due to their smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2023 period. The median size premium for the Utility Proxy Group with a market capitalization of $4.249 billion falls in the 5th decile, while the Company's estimated market capitalization of $606.404 million places it in the 8th decile. The size premium spread between the 5th decile and the 8th decile is 0.19%. Even though a 0.19% upward size adjustment is indicated, I conservatively applied a size premium of 0.05% to the Company's range of indicated common equity cost rates.

[50] $628,233,491 (requested rate base) * 60.88% (proposed capital structure) * 158.6% (market-to-book ratio of the Utility Proxy Group) as demonstrated on page 2 of Exhibit DWD-7.

Q. SHOULD THE COMMISSION CONSIDER ATMOS ENERGY'S KENTUCKY OPERATIONS AS A STAND-ALONE COMPANY?

A. Yes, it should. Because it is Atmos Energy's Kentucky rate base to which the overall rates of return set forth in this proceeding will be applied, they should be evaluated as a stand-alone entity. To do otherwise would be discriminatory, confiscatory, and inaccurate. It is also a basic financial precept that the use of the funds invested give rise to the risk of the investment. As Brealey and Myers state:

> *The true cost of capital depends on the use to which the capital is put.*
>
> ***
>
> ***Each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put***. (italics and bold in original) [51]

Morin confirms Brealey and Myers when he states:

> Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost of the investors and not the cost of the specific capital sources employed by the investors. The true cost of capital depends on the use to which the capital is put and not on its source. The Hope and Bluefield doctrines have made clear that the relevant considerations in calculating a company's cost of capital are the alternatives available to investors and the returns and risks associated with those alternatives.[52]

Additionally, Levy and Sarnat state:

> The firm's cost of capital is the discount rate employed to discount the firm's average cash flow, hence obtaining the value of the firm. It is also the weighted average cost of capital, as we shall see below. The weighted average cost of capital should be employed for project evaluation… only in cases where the risk profile of the new projects is a "carbon copy" of the risk profile of the firm.[53]

[51] Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance, McGraw-Hill, Third Edition, 1988, at 173, 198.

[52] Morin, at 581.

[53] Haim Levy & Marshall Sarnat, Capital Investment and Financial Decisions, Prentice/Hall International, 1986, at 465.

Although Levy and Sarnat discuss a project's cost of capital relative to a firm's cost of capital, these principles apply equally to the use of a proxy group-based cost of capital. Each company must be viewed on its own merits, regardless of the source of its equity capital. As *Bluefield* clearly states:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; [54]

In other words, it is the "risks and uncertainties" surrounding the property employed for the "convenience of the public" which determines the appropriate level of rates. In this proceeding, the property employed "for the convenience of the public" is the rate base of Atmos Energy's Kentucky operations. Thus, it is only the risk of investment in Atmos Energy's Kentucky operations that is relevant to the determination of the cost of common equity to be applied to the common equity-financed portion of that rate base.

In addition, in the Fama and French article previously cited, the authors[55] proposed that their three-factor model include the SMB (Small Minus Big) factor, which indicates that small capitalization firms are more risky than large capitalization firms, confirming that size is a risk factor which must be taken into account in estimating the cost of common equity.

Consistent with the financial principle of risk and return discussed previously, and the stand-alone nature of ratemaking, an upward adjustment must

[54] *Bluefield,* at 6.
[55] Fama & French, at 39.

be applied to the indicated cost of common equity derived from the cost of equity models of the proxy groups used in this proceeding.

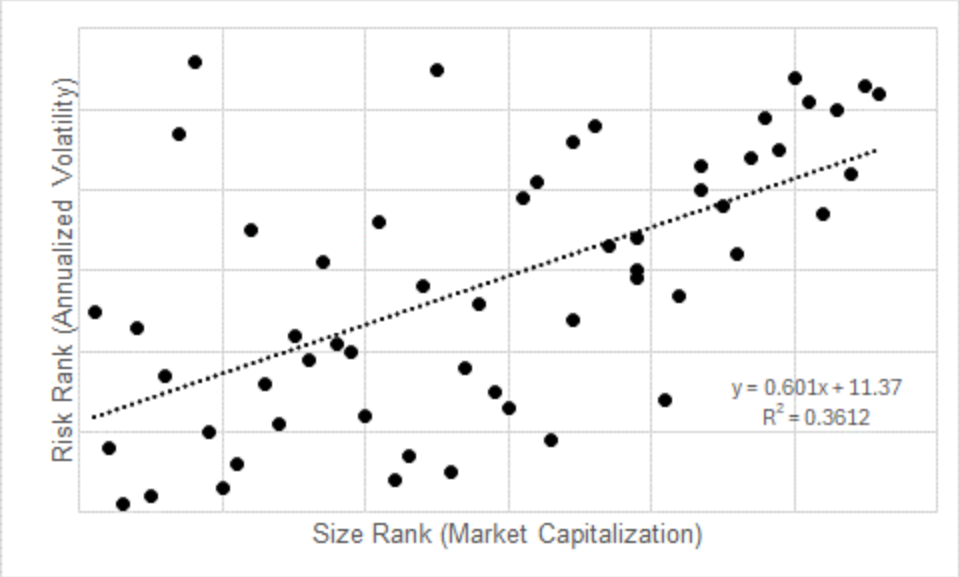
Q. HAS THE COMMISSION CONSIDERED ATMOS ENERGY KENTUCKY'S OPERATIONS ON A STANDALONE BASIS AS IT RELATES TO OTHER REGULATORY MATTERS?

A. Yes. The Commission has treated Atmos Energy Kentucky operations on a standalone basis for accumulated deferred income tax and net operating loss tax-related purposes as noted in the Direct Testimony of Company Witness Mr. Joel Multer.

Q. HAVE YOU CONDUCTED STUDIES TO DETERMINE IF SIZE AND RISK FOR UTILITIES IS RELATED?

A. Yes. I have performed three studies which link size and risk for utilities and show that utility companies become riskier as their size decreases. The first study included the universe of electric, gas, and water companies included in *Value Line* Standard Edition. I calculated the annualized volatility (a measure of risk) for each of the utilities and relied on the current market capitalization (a measure of size) as reported by *Value Line* for each company. After ranking the companies by size (largest to smallest) and risk (least risky to most risky), I made a scatter plot of the data, as shown on Chart 1, below:

Chart 1: Relationship Between Size and Risk for the *Value Line* Universe of Utility Companies[56]



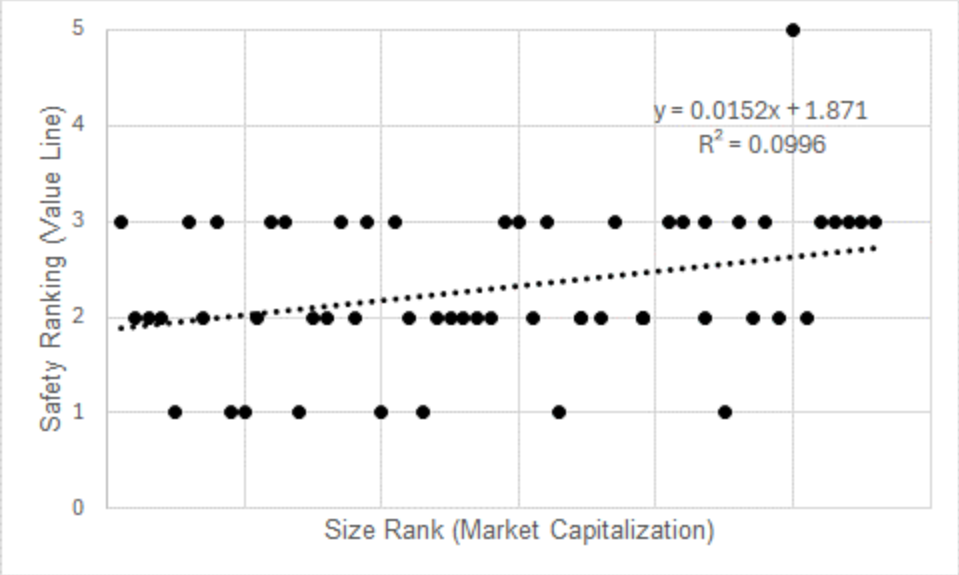
As shown in Chart 1 above, as company size decreases (increasing size rank), the annualized volatility increases, linking size and risk for utilities, which is significant at 95.0% confidence level.

The second study used the same universe of companies, but instead of using annualized volatility, I used the *Value Line* Safety Ranking, which is another measure of total risk.[57] After ranking the companies by size and Safety Ranking, I made a scatterplot of those data, as shown on Chart 2, below.

[56] Source: *Value Line*.

[57] *Value Line* also ranks stocks for Safety by analyzing the total risk of a stock compared to the approximately 1,700 stocks in the *Value Line* universe. Each of the stocks tracked in the *Value Line Investment Survey* is ranked in relationship to each other, from 1 (the highest rank) to 5 (the lowest rank). Safety is a quality rank, not a performance rank, and stocks ranked 1 and 2 are most suitable for conservative investors; those ranked 4 and 5 will be more volatile. Volatility means prices can move dramatically and often unpredictably, either down or up. The major influences on a stock's Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

Chart 2: Relationship Between Size and Safety Ranking for the *Value Line* Universe of Utility Companies[58]



Similar to the first study, as company size decreases, Safety Ranking degrades, indicating a link between size and risk for utilities. This study is also significant at the 95% confidence level.

In view of the evidence in the academic literature regarding the presence of the size premium and the empirical evidence of a link between size and risk for utility companies, I strongly urge the Commission to reconsider its position on granting premiums for small relative size.

B. Credit Risk Adjustment

Q. PLEASE DISCUSS YOUR PROPOSED CREDIT RISK ADJUSTMENT.

A. Atmos Energy's long-term issuer ratings are A1 and A- from Moody's and S&P, respectively, which are less risky than the average long-term ratings for the Utility Proxy Group of A2 and A-, respectively.[59] Hence, a downward credit risk adjustment is necessary to reflect the less risky credit rating, i.e., A1, of Atmos

[58] Source: *Value Line*.
[59] Source of Information: S&P Capital IQ.

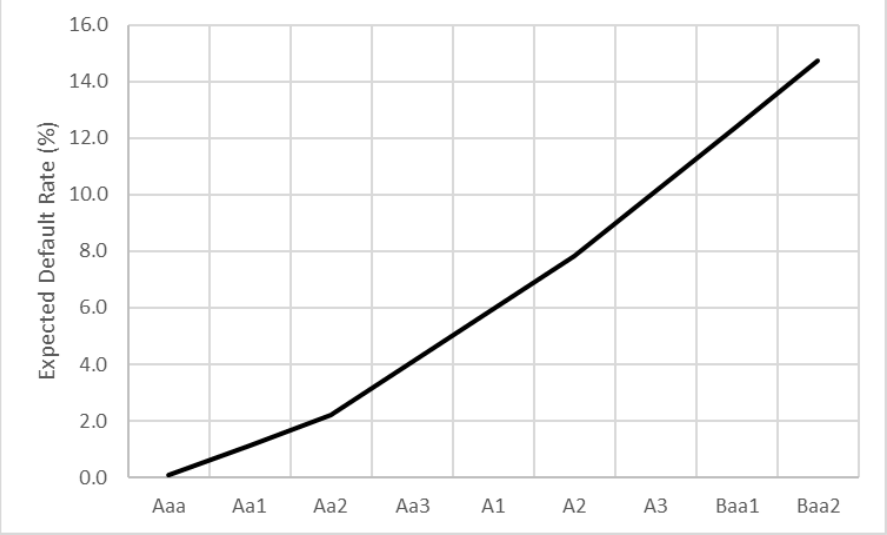
Energy relative to the A2 average Moody's bond rating of the Utility Proxy Group.[60]

An indication of the magnitude of the necessary downward adjustment to reflect the lower credit risk inherent in an A1 bond rating is one-third of a recent three-month average spread between Moody's A- and Aa-rated public utility bond yields of 0.11%, shown on page 2 of Exhibit DWD-3, or 0.04%.[61]

Q. WHY IS IT IMPORTANT THAT YOU MAKE A CREDIT RISK ADJUSTMENT?

A. It is important to reflect a company's relative financial risk, as companies with riskier bond ratings have a higher risk of default, and because of that, equity investors would require a higher return on their investment. To illustrate the risk of default related to changes in bond rating, Chart 3 below presents Moody's Idealized Cumulative Expected Default Rates for debt obligations with maturities lasting 30-years based on the respective rating.

Chart 3: Moody's Idealized Cumulative Expected Default Rates Based on Debt Obligations with 30-Year Maturities



[60] As shown on page 3 of Exhibit DWD-3.
[61] 1/3 * 0.11% = 0.04%.

As shown in Chart 3, Moody's notes an observable difference in the default rates based on each respective rating. Therefore, even though credit ratings might be similar, the default rates indicate that different ratings equate to different risks.

C. Flotation Cost Adjustment

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (*e.g.*, underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED COMMON EQUITY COST RATE?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free….[Flotation costs] must be recovered through a rate of return adjustment.[62]

[62] Morin, at 329.

Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS AN ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT POST-TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, $0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in

investment. Assuming the investor in that stock requires a 10% return on his or her invested $1.00 (i.e., a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION COSTS?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[63] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[64] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHY THE ROE MUST INCLUDE FLOTATION COSTS TO REALIZE ITS REQUIRED RETURN?

A. Yes, I can. As shown in Exhibit DWD-8, because of flotation costs, an authorized return of 10.85% would be required to realize an ROE of 10.75% (i.e., a 10-basis point flotation cost adjustment). If flotation costs are not recovered, the growth rate falls and the ROE decreases to 10.65% (i.e., below the required return).[65]

[63] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at 342.

[64] Morin, at 337-339.

[65] Exhibit DWD-8 is provided for illustrative purposes only. Please note that I have not relied on the results of the analysis in determining my recommended ROE or range.

Q. HOW DID YOU CALCULATE THE FLOTATION COST ALLOWANCE?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by ATO in its equity issuances for the period beginning 2016. Based on the issuance costs shown on page 1 of Exhibit DWD-9, an adjustment of 0.06% is required to reflect the flotation costs applicable to the Utility Proxy Group.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS TO THE INDICATED RANGES OF ROEs APPLICABLE TO THE UTILITY PROXY GROUP.

A. The summary of my adjustments to the indicated ranges of the ROEs applicable to the Utility Proxy Group is as follows:

Table 13: Summary of Adjustments to the Indicated Ranges of ROEs Applicable to the Utility Proxy Group

Indicated Range Before Adjustment	9.93% - 12.05%
Size Adjustment	0.05%
Credit Risk Adjustment	-0.04%
Flotation Cost Adjustment	0.06%
Indicated Range After Adjustment	10.00% - 12.12%

As shown on Table 13, the range of ROEs applicable to the Company is between 10.00% and 12.12%.

D. Other Considerations

Q. DOES THE COMPANY'S UTILIZATION OF THE PIPELINE REPLACEMENT PROGRAM ("PRP") AFFECT ITS RELATIVE RISK TO THE UTILITY PROXY GROUP?

A. No. The *Hope* and *Bluefield* "Comparable Earnings" standard requires the allowed ROE to be commensurate with the returns on investments of similar risk. The cost of capital is a comparative exercise, so if the mechanism is common throughout the companies on which one bases their analyses, the comparative risk is zero, because any effect of the perceived reduced risk of the mechanism(s) by investors would be reflected in the market data of the proxy group. To the extent the proxy companies have mechanisms in place to address revenue shortfalls and cost recovery, the PRP only serves to make it more comparable to its peers and have no impact on comparative risk.

To that point, Exhibit DWD-10 provides a summary of rate stabilization mechanisms currently in effect at each gas utility subsidiary of the proxy group companies. As Exhibit DWD-10 demonstrates, substantially all the proxy companies have infrastructure recovery mechanisms in place.[66]

Q. ARE YOU AWARE OF ANY STUDIES THAT HAVE ADDRESSED THE RELATIONSHIP BETWEEN RATE STABILIZATION MECHANISMS, GENERALLY, AND ROE?

A. Yes. In March 2014, The Brattle Group ("Brattle") published a study addressing the effect of revenue decoupling structures on the cost of capital for electric utilities. In its report, which extended a prior analysis focused on natural gas distribution

[66] Only five of the 23 proxy group operating companies do not have a capital recovery mechanism.

utilities, Brattle pointed out that although decoupling structures may affect revenue, net income still can vary. Brattle further noted that the distinction between diversifiable and non-diversifiable risk is important to equity investors, and the relationship between decoupling and the cost of equity should be examined in that context. Further to that point, Brattle noted that although reductions in total risk may be important to bondholders, only reductions in non-diversifiable business risk would justify a reduction to the ROE. In November 2016, the Brattle study was updated based on data through the fourth quarter of 2015.

Brattle's empirical analysis examined the relationship between decoupling and the After-Tax Weighted Average Cost of Capital for a group of electric utilities that had implemented decoupling structures in various jurisdictions throughout the United States. As with Brattle's 2014 study, the updated study found no statistically significant link between the cost of capital and revenue decoupling structures.

In addition, I co-authored a peer-reviewed article in Energy Policy with Dr. Richard A. Michelfelder and my colleague Pauline M. Ahern which examines the relationship between decoupling and ROE among electric, gas, and water utilities. Using the generalized consumption asset pricing model, they found decoupling to have no statistically significant effect on investor perceived risk and the ROE.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF THE COMPANY'S PRP ON ROE?

A. The presence of Atmos Energy's PRP rider does not affect the Company's ROE. Atmos Energy's PRP rider does not affect the ROE because it is similar to riders present in the operating companies of the Utility Proxy Group used to derive the

ROE. Since this is the case, the lower risk of having a PRP (if any) would already be subsumed in the market data for the Utility Proxy Group.

Furthermore, several studies show that rate stabilization mechanisms like the PRP do not materially affect the investor-required return for those companies. Given that, the Company's PRP rider does not lower the comparative risk of the Company relative to the Utility Proxy Group and therefore, the ROE should not be adjusted due to the Company's PRP rider.

VIII. CONCLUSION

Q. WHAT IS YOUR RECOMMENDED ROE FOR ATMOS ENERGY?

A. Given the indicated ROE ranges applicable to the Utility Proxy Group and Company, I conclude that an appropriate ROE for the Company is 10.95%.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.95% FAIR AND REASONABLE TO ATMOS ENERGY AND ITS CUSTOMERS?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Dylan W. D'Ascendis, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Dylan W. D'Ascendis

STATE OF NEW JERSEY

COUNTY OF BURLINGTON

SUBSCRIBED AND SWORN to before me by Dylan W. D'Ascendis on this the 20 day of September, 2024.

Margaret A Clancy

Notary Public

My Commission Expires: 6/9/2029

MARGARET A CLANCY
Notary Public, State of New Jersey
My Commission Expires Jun 9, 2029

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and is a leading expert witness with respect to cost of capital, capital structure, and valuation. He has served as a consultant for investor-owned and municipal utilities and authorities for 15 years. Dylan has testified as an expert witness on over 150 occasions regarding rate of return, cost of service, rate design, and valuation before more than 40 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Expert Witness Testimony
- Rates and Regulation
- Return on Equity
- Valuation
- Utility Regulations
- Rate Case Planning, Management, and Support
- Utility Benchmarking

Recent Articles and Speeches

- "Decoupling, Risk Impacts, and the Cost of Capital." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal. March 2020
- "Decoupling Impact and Public Utility Conservation Investment." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal. 130 (2019), 311-319
- "Establishing Alternative Proxy Groups." Presentation before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum. April 4, 2019. New Orleans, LA
- "Past Is Prologue: Future Test Year." Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit. May 2, 2017. Savannah, GA
- "Comparative Evaluation of the Predictive Risk Premium Model^{TM}, the Discounted Cash Flow Model and the Capital Asset Pricing Model." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley. The Electricity Journal. May 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks." Presentation before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum. April 17-18, 2013. Indianapolis, IN

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the city
- Co-authored a valuation report on behalf of a large investor-owned utility in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Alaska Power Company	08/23	Alaska Power Company	Docket No. TA 909-2 / U-23-054	Capital Structure
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27084	Determination of Cost-of-Capital Parameters
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	06/24	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-24-0130	Rate of Return
Arizona Water Company	05/24	Arizona Water Company – Northern Group	Docket No. W-01445A-24-0117	Rate of Return
Foothills Water & Sewer, LLC	10/23	Foothills Water & Sewer, LLC	Docket No. WS-21182A-23-0292	Rate of Return and Fair Value Rate Base
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Summit Utilities Arkansas, Inc.	01/24	Summit Utilities Arkansas, Inc.	Docket No. 23-079-U	Rate of Return
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Delaware Public Service Commission				
Artesian Water Company, Inc.	04/23	Artesian Water Company, Inc.	Docket No. 23-0601	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Delmarva Power & Light Co.	12/22	Delmarva Power & Light Co.	Docket No. 22-0897 (Electric)	Return on Equity
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/24	Tampa Electric Company	Docket No. 20240025-EI	Return on Equity
Peoples Gas System, Inc.	04/23	Peoples Gas System, Inc.	Docket No. 20230023-GU	Rate of Return
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System, Inc.	09/20	Peoples Gas System, Inc.	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Aqua Illinois, Inc.	01/24	Aqua Illinois, Inc.	Docket No. 24-0044	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0082 (Electric)	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0067 (Gas)	Return on Equity
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				

Sponsor	Date	Case/Applicant	Docket No.	Subject
Bluegrass Water Utility Operating Company	02/23	Bluegrass Water Utility Operating Company	2022-00432	Return on Equity
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy Corporation	04/20	Atmos Energy Corporation	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	05/23	Northern Utilities, Inc. d/b/a Unitil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy Service Company	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy Corporation	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	9/23	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 23-80	Rate of Return
Unitil Corporation	9/23	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 23-81	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	D.P.U. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy Corporation	03/19	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Atmos Energy Corporation	07/18	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Confluence Rivers Utility Operating Company, Inc.	01/23	Confluence Rivers Utility Operating Company, Inc.	Case No. WR-2023-0006/SR-2023-0007	Rate of Return
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/23	Southwest Gas Corporation	Docket No. 23-09012	Return on Equity
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
New Jersey Natural Gas Company	01/24	New Jersey Natural Gas Company	Docket No. GR24010071	Rate of Return
Middlesex Water Company	05/23	Middlesex Water Company	Docket No. WR23050292	Rate of Return
FirstEnergy Service Company	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Atlantic City Electric Company	02/23	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy Service Company	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
New Mexico Gas Company	09/23	New Mexico Gas Company	Case No. 23-00255-UT	Return on Equity
Southwestern Public Service Co.	11/22	Southwestern Public Service Co.	Case No. 22-00286-UT	Return on Equity
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Old North State Water Co., Inc.	06/24	Old North State Water Co., Inc.	Docket No. W-1300, Sub 100	Rate of Return
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
FirstEnergy	06/24	Ohio Edison Co., Cleveland Electric Illuminating Co., Toledo Edison Co.	Case No. 24-0468-EL-AIR	Rate of Return
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Columbia Water Company	05/23	Columbia Water Company	Docket No. R-2023-3040258	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
FirstEnergy	04/22	Pennsylvania Electric Company	Docket No. R-2024-3047068	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
CSWR – Limestone Water Utility Operating Company	07/24	CSWR – Limestone Water Utility Operating Company	Docket No. 24-00044	Capital Structure, Cost of Debt, Return on Equity
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
CSWR – Texas Utility Operating Company, LLC	02/23	CSWR – Texas Utility Operating Company, LLC	Docket No. 54565	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Texas Railroad Commission				
Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	Docket No. OS-23-00013758	Return on Equity
Virginia State Corporation Commission				
Aqua Virginia, Inc.	07/23	Aqua Virginia, Inc.	PUR-2023-00073	Rate of Return
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
FirstEnergy Service Company	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
FirstEnergy Service Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
FirstEnergy Service Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

Atmos Energy Corporation
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Atmos Energy Corporation
Recommended Capital Structure and Cost Rates for Ratemaking Purposes

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	38.93%	4.11%	(1)	1.60%
Short-Term Debt	0.19%	17.14%	(1)	0.03%
Common Equity	60.88%	10.95%	(2)	6.67%
Total	100.00%			8.30%

Notes:

(1) Company-provided
(2) From page 2 of this Schedule.

Atmos Energy Corporation
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Six Natural Gas Distribution Companies	Proxy Group of Six Natural Gas Distribution Companies (excl. PRPM)
1.	Discounted Cash Flow Model (DCF)(1)	9.93%	9.93%
2.	Risk Premium Model (RPM) (2)	10.80%	10.75%
3.	Capital Asset Pricing Model (CAPM) (3)	11.36%	11.28%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.05%	11.97%
5.	Indicated Range of Common Equity Cost Rates before Adjustment for Company-Specific Risk	9.93% - 12.05%	9.93% - 11.97%
6.	Size Adjustment (5)	0.05%	0.05%
7.	Credit Risk Adjustment (6)	-0.04%	-0.04%
8.	Flotation Cost Adjustment (7)	0.06%	0.06%
9.	Recommended Range of Common Equity Cost Rates after Adjustment for Company-Specific Risk	10.00% - 12.12%	10.00% - 12.04%
10.	Recommended Cost of Common Equity Cost Rate	10.95%	

Notes: (1) From page 1 of Schedule DWD-2
(2) From page 1 of Schedule DWD-3
(3) From page 1 of Schedule DWD-4
(4) From page 1 of Schedule DWD-6
(5) Adjustment to reflect the Company's greater business risk relative to the Utility Proxy Group as detailed in Mr. D'Ascendis' Direct Testimony.
(6) Company-specific risk adjustment to reflect Atmos' lower risk due to a less risky long-term rating relative to the proxy group as detailed in Mr. D'Ascendis' Direct Testimony.
(7) From Schedule DWD-9.

Atmos Energy Corporation
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Six Natural Gas Distribution Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.72 %	7.00 %	7.00 %	7.40 %	7.00 %	7.10 %	2.82 %	9.92 %
New Jersey Resources Corporation	3.83	5.00	NA	6.00	5.87	5.62	3.94	9.56
NiSource Inc.	3.64	9.50	6.00	7.50	7.17	7.54	3.78	11.32
Northwest Natural Holding Company	5.22	6.50	NA	2.80	4.40	4.57	5.34	9.91
ONE Gas, Inc.	4.14	3.50	5.00	5.00	3.00	4.13	4.23	8.36
Spire Inc.	4.90	4.50	5.00	6.36	6.45	5.58	5.04	10.62
							Average	9.95 %
							Median	9.91 %
							Average of Mean and Median	9.93 %

NA= Not Available
NMF= Not Meaningful Figure

Notes:

(1) Indicated dividend at 07/31/2024 divided by the average closing price of the last 60 trading days ending 07/31/2024 for each company.
(2) From pages 2 through 7 of this Schedule.
(3) Average of columns 2 through 5 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 6) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.72% x (1+(1/2 x 7.10%)) = 2.82%.
(5) Column 6 + column 7.

Source of Information:
Value Line Investment Survey
www.zacks.com Downloaded on 07/31/2024
www.yahoo.com Downloaded on 07/31/2024
S&P Capital IQ

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 116.33 | P/E RATIO 16.8 (Trailing: 17.4 Median: 20.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 4 Lowered 2/16/24
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Lowered 3/22/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$102-$148	$125 (5%)

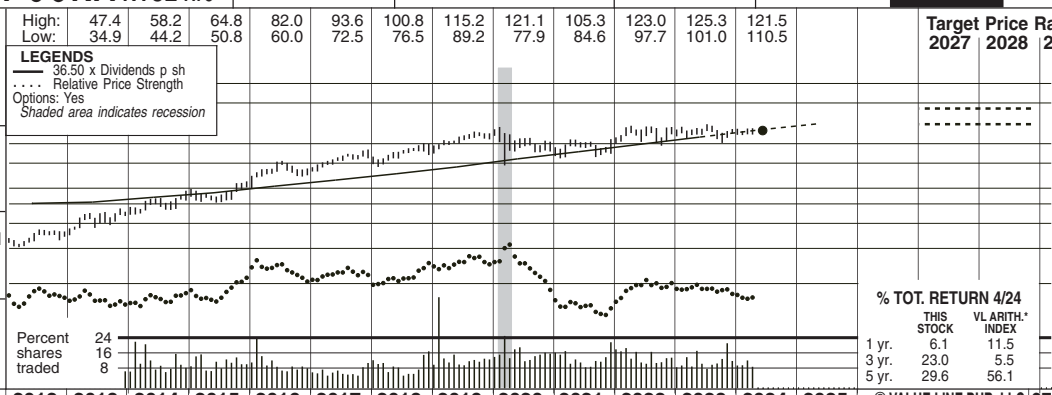
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+30%)	*10%*
Low	125	(+5%)	*5%*

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	314	322	358
to Sell	281	280	295
Hld's(000)	136508	137279	137294

	2018	2019	2020	2021	2022	2023	2024	2025
High:	100.8	115.2	121.1	105.3	123.0	125.3	121.5	
Low:	76.5	89.2	77.9	84.6	97.7	101.0	110.5	



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.1	11.5
3 yr.	23.0	5.5
5 yr.	29.6	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	*27.10*	*28.50*	Revenues per sh [A]	*37.15*
4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	*10.95*	*11.75*	"Cash Flow" per sh	*13.65*
2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	*6.75*	*7.20*	Earnings per sh [AB]	*8.35*
1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	*3.22*	*3.46*	Div'ds Decl'd per sh [C] ■	*4.25*
5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	*20.00*	*20.25*	Cap'l Spending per sh	*20.00*
22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	*75.30*	*78.60*	Book Value per sh	*83.50*
90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	*155.00*	*158.00*	Common Shs Outst'g [D]	*175.00*
13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.5*
.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08			Relative P/E Ratio	*.90*
4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%			Avg Ann'l Div'd Yield	*3.1%*
						4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	*4200*	*4500*	Revenues ($mill) [A]	*6500*
						289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	*1025*	*1115*	Net Profit ($mill)	*1475*
						39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	*15.5%*	*16.0%*	Income Tax Rate	*25.0%*
						5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	*24.4%*	*24.8%*	Net Profit Margin	*22.7%*
						44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
						55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
						5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	*19450*	*20700*	Total Capital ($mill)	*24350*
						6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	*21900*	*23000*	Net Plant ($mill)	*27000*
						6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
						9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
						9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*9.0%*	*9.0%*	Return on Com Equity	*10.0%*
						4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
						50%	51%	50%	50%	48%	48%	49%	49%	49%	49%	*49%*	*49%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $7535.7 mill. **Due in 5 Yrs** $915.0 mill.
LT Debt $7526.1 mill. **LT Interest** $135.0 mill.
(LT interest earned: 8.3x; total interest coverage: 8.3x)
Leases, Uncapitalized Annual rentals $41.3 mill.

Pfd Stock None

Pension Assets-9/23 $502.4 mill.
Oblig. $431.6 mill.
Common Stock 150,877,056 shs.
as of 5/3/24

MARKET CAP: $17.6 billion (Large Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	51.6	15.4	262.5
Other	2996.1	870.4	1169.9
Current Assets	3047.7	885.8	1432.4
Accts Payable	496.0	336.1	367.9
Debt Due	2386.4	253.4	9.6
Other	720.2	763.1	677.7
Current Liab.	3602.6	1352.6	1055.2
Fix. Chg. Cov.	1238%	1059%	1070%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-4.0%	-.5%	*5.0%*
"Cash Flow"	6.5%	7.0%	*6.5%*
Earnings	9.5%	9.0%	*7.0%*
Dividends	7.0%	8.5%	*7.5%*
Book Value	9.5%	12.0%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	1647.2	*786.5*	*607.8*	*4200*
2025	*1250*	*1725*	*865*	*660*	*4500*

Fiscal Year Ends	EARNINGS PER SHARE [A B E] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	2.85	*1.00*	*.82*	*6.75*
2025	*2.26*	*2.94*	*1.10*	*.90*	*7.20*

Cal-endar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805	.805			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2023: 66.5%, residential; 28.0%, commercial; 3.8%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/23 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy has performed nicely, from an earnings standpoint, thus far in fiscal 2024 (ends September 30th). Through the first half, per-share profits of $4.93 were 12.3% higher than the $4.39 amount registered for the same period last year. This was brought about partially by positive rate-case outcomes. Lower bad-debt expense also helped. Furthermore, results were favorably impacted by legislation to reduce property-tax expenses in Texas. But a rise in both depreciation expense and interest charges provided somewhat of an offset. Nevertheless, for the entire year, it appears that the bottom line will increase around 10%, to $6.75 per share, relative to fiscal 2023's $6.10 tally. Concerning fiscal 2025, share net may grow another 7% or so, to $7.20, as operating margins expand further.

There has been action on the rate-filing front. During the first six months, Atmos managed to complete some regulatory proceedings leading to a $138.4 million boost in annual operating income. What's more, there were ratemaking initiatives in progress at the conclusion of March seeking $96.4 million of annual operating income. Of course, there are no guarantees that the company will receive everything it desires.

The capital spending target for fiscal 2024 was raised from $2.9 billion to $3.1 billion. The revised estimate marks a 10.5% increase from fiscal 2023's $2.8 billion figure. Like last year, a substantial amount of the resources is being used to enhance the safety and reliability of Atmos' natural gas distribution and transmission systems. Leadership adds that it projects total capital expenditures from fiscal 2024 through fiscal 2028 to be roughly $17 billion. A meaningful portion of the investments will continue to be deployed to where they are currently. Assuming that finances remain healthy, the company ought to have minimal difficulty accomplishing these objectives.

These top-quality shares have strengthened some in price over the past six months. That's due partly, we think, to the energy firm's solid earnings of late. However, long-term total return potential looks unspectacular. The equity is untimely, as well.

Frederick L. Harris, III *May 24, 2024*

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early Aug. **(C)** Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. **(D)** In millions. **(E)** Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

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NEW JERSEY RES. NYSE-NJR

RECENT PRICE **44.12** | P/E RATIO **14.9** (Trailing: 17.3 Median: 17.0) | RELATIVE P/E RATIO **0.82** | DIV'D YLD **3.9%** | **VALUE LINE**

TIMELINESS 4 Raised 3/29/24
SAFETY 2 Lowered 4/17/20
TECHNICAL 5 Lowered 5/3/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

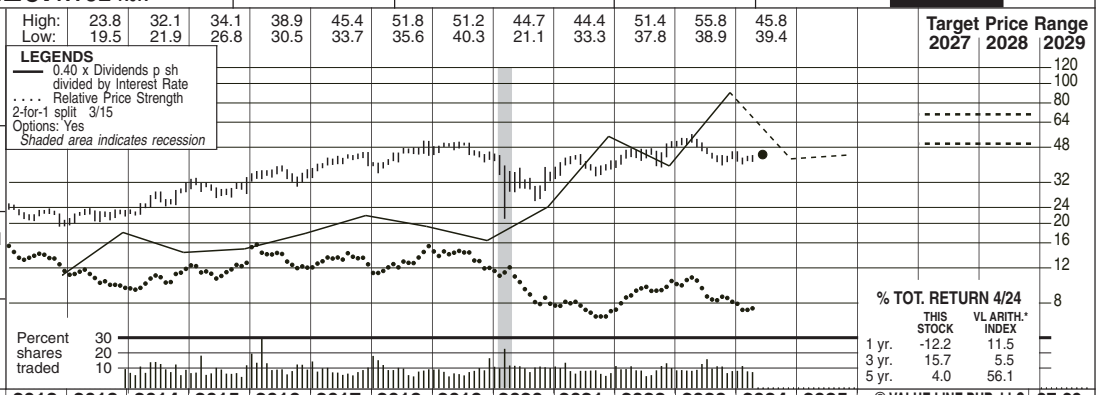
Low-High	Midpoint (% to Mid)
$37-$60	$49 (10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+60%)	*15%*
Low	50	(+15%)	*7%*

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	157	153	161
to Sell	156	163	143
Hld's(000)	71570	69494	70304



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.38	20.12	*21.50*	*22.00*	Revenues per sh [A]	*25.00*
1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.86	4.22	*4.55*	*4.60*	"Cash Flow" per sh	*5.25*
1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.70	*2.95*	*3.00*	Earnings per sh [B]	*3.50*
.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	*1.68*	*1.76*	Div'ds Decl'd per sh [C] ■	*1.95*
.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	6.50	5.13	*4.40*	*5.50*	Cap'l Spending per sh	*6.25*
8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	19.00	20.40	*22.30*	*23.65*	Book Value per sh [D]	*27.00*
84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	95.64	97.57	*100.00*	*100.00*	Common Shs Outst'g [E]	*100.00*
12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	.98	1.02			Relative P/E Ratio	*.95*
3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%			Avg Ann'l Div'd Yield	*4.0%*
3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	*2150*	*2200*	Revenues ($mill) [A]	*2500*
176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	261.8	*295*	*300*	Net Profit ($mill)	*350*
30.2%	26.3%	15.5%	17.2%	--	--	NMF	10.3%	21.4%	15.8%	*21.5%*	*22.0%*	Income Tax Rate	*22.0%*
4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.3%	*13.7%*	*13.6%*	Net Profit Margin	*14.0%*
38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	*57.5%*	*57.0%*	Long-Term Debt Ratio	*55.0%*
61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	*42.5%*	*43.0%*	Common Equity Ratio	*45.0%*
1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	*5250*	*5500*	Total Capital ($mill)	*6000*
1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	*5150*	*5250*	Net Plant ($mill)	*5550*
12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	5.6%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	*13.0%*	*12.5%*	Return on Shr. Equity	*13.0%*
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	*13.0%*	*12.5%*	Return on Com Equity	*13.0%*
11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.6%	*5.5%*	*5.0%*	Retained to Com Eq	*5.5%*
40%	50%	60%	59%	40%	59%	60%	56%	53%	58%	*57%*	*59%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $3070.8 mill. **Due in 5 Yrs** $580 mill.
LT Debt $2726.2 mill. **LT Interest** $125 mill.
Incl. $9.3 mill. capitalized leases.
(Interest coverage: 4.85x)
Pension Assets-9/23 $405.0 mill.
Oblig. $493.7 mill.
Pfd Stock None

Common Stock 98,822,278 shs.
as of 5/3/24

MARKET CAP: $4.4 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	1.1	1.0	5.0
Other	755.0	531.1	548.7
Current Assets	756.1	532.1	553.7
Accts Payable	156.6	151.8	127.2
Debt Due	499.1	368.3	344.6
Other	448.5	286.5	317.3
Current Liab.	1104.2	806.6	789.1
Fix. Chg. Cov.	545%	520%	480%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.0%	-6.0%	*2.5%*
"Cash Flow"	7.0%	4.5%	*5.0%*
Earnings	5.0%	2.5%	*5.0%*
Dividends	6.5%	6.5%	*5.0%*
Book Value	7.5%	7.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	657.9	*450*	*574.9*	*2150*
2025	*680*	*575*	*460*	*485*	*2200*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.04	.50	2.50
2023	1.14	1.16	.10	.30	2.70
2024	.74	1.41	*.05*	*.75*	*2.95*
2025	*.75*	*1.45*	*.05*	*.75*	*3.00*

Calendar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42	.42			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 576,000 cust. at 9/30/23. Fiscal 2023 volume: 128 bill. cu. ft. (23% interruptible, 50% residential, commercial & firm transportation, 27% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2023 dep. rate: 2.8%. Has 1,350 empls. Off./dir. own less than 1% of common; BlackRock, 15.9%; Vanguard, 11.4% (12/23 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources delivered a strong fiscal 2024 second-quarter performance. (Fiscal year ends September 30th.) Despite a lower-than-expected revenue figure due to falling natural gas prices, the company's cost structure allowed earnings to remain unfettered. Indeed, net financial earnings exceeded our projections, landing at $1.41 per share, well above the prior year's tally. This brings the total for the first six months of fiscal 2024 to $2.15, just shy of the $2.30 in the year before, which was boosted by a unique winter storm. The performance was bolstered by significant capital investments of more than $850 million since the last rate case in 2021. Too, the company's SAVEGREEN program, a large energy efficiency filing, helped in catering to New Jersey's increasingly sustainability-focused regulatory climate. Despite some broader headwinds, the company continues to manage its operating costs well.

We have raised our earnings outlook for the next two years. The energy services segment is poised to contribute to our increased expectations due to the earlier mentioned SAVEGREEN program within the context of a particularly strong residential construction market and efficiency incentives in its operating region. On a similar note, Clean Energy Ventures is experiencing rapid deployment with 34 megawatts under construction and a solar pipeline of over 870 megawatts of investment opportunities. Most importantly for sustainable earnings performances henceforth is a new rate case progressing through regulatory channels that should amplify earnings performance substantially in fiscal 2026, if passed.

New Jersey's regional strength provides a solid base for sustainable growth. With a favorable regulatory backdrop characterized by a commitment to the transition to sustainable energy systems, infrastructure investment opportunities are wide, which will help to grow the company's earnings base for the foreseeable future.

The stock remains favorable for low risk and steady income characteristics. The issue has returned about 6% over the past three months but still offers decent value from its income component.

Earl B. Humes *May 24, 2024*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early August.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2023: $585 million, $6.00/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	60

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NISOURCE INC. NYSE-NI

RECENT PRICE **28.80** | P/E RATIO **16.9** (Trailing: 17.1 Median: 21.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **3.8%** | **VALUE LINE**

TIMELINESS 3 Raised 3/22/24
SAFETY 2 Raised 2/23/24
TECHNICAL 4 Raised 5/24/24
BETA .95 (1.00 = Market)

18-Month Target Price Range

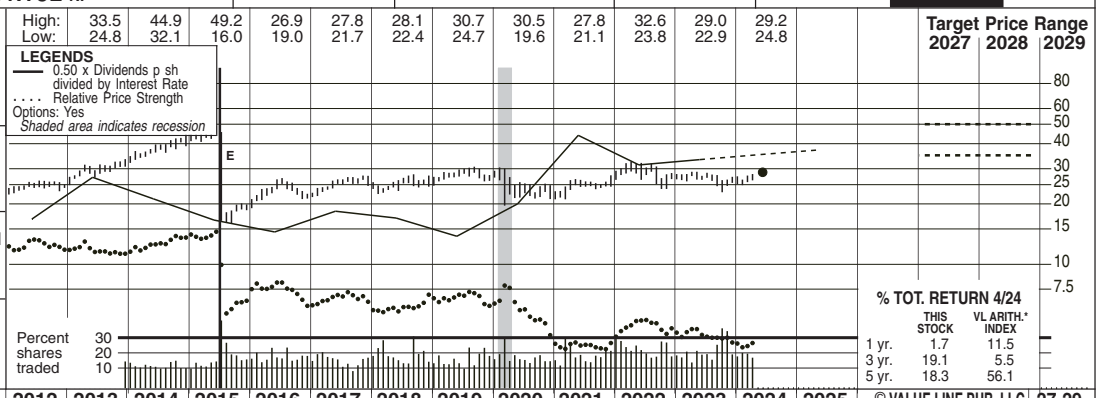
Low-High	Midpoint (% to Mid)
$25-$40	$33 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+75%)	*17%*
Low	35	(+20%)	*8%*

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	249	278	313
to Sell	256	234	253
Hld's(000)	393166	394475	413866



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.23	12.33	***13.80***	***14.55***	Revenues per sh	***16.10***
3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.47	3.64	***3.80***	***4.80***	"Cash Flow" per sh	***4.40***
1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	1.60	***1.70***	***1.85***	Earnings per sh [A]	***2.20***
.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	***1.06***	***1.12***	Div'ds Decl'd per sh [B] ■	***1.20***
3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	6.32	5.93	***7.00***	***6.50***	Cap'l Spending per sh	***6.75***
17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	13.14	22.71	***23.20***	***22.15***	Book Value per sh [C]	***20.40***
274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	411.10	446.38	***450.00***	***450.00***	Common Shs Outst'g [D]	***450.00***
12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	21.3	18.7	18.0	19.6	16.8	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***19.0***
.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	1.13	.96	.99	11.8	.97			Relative P/E Ratio	***1.05***
5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%			Avg Ann'l Div'd Yield	***3.0%***
						6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	5505.4	***6200***	***6550***	Revenues ($mill)	***7250***
						530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	716.3	***765***	***835***	Net Profit ($mill)	***990***
						36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	17.2%	17.8%	***19.0%***	***19.0%***	Income Tax Rate	***19.0%***
						--	--	--	--	--	--	--	2.0%	2.3%	3.5%	***3.0%***	***2.5%***	AFUDC % to Net Profit	***2.5%***
						56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	52.2%	***52.5%***	***52.5%***	Long-Term Debt Ratio	***55.0%***
						43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	31.6%	45.5%	***40.0%***	***40.0%***	Common Equity Ratio	***37.5%***
						14331	9792.0	10129	11832	12856	13843	14972	16131	17099	21192	***22000***	***21000***	Total Capital ($mill)	***24450***
						16017	12112	13068	14360	15543	16912	16620	17882	19843	22275	***24500***	***25750***	Net Plant ($mill)	***28000***
						5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	3.4%	***3.5%***	***4.0%***	Return on Total Cap'l	***4.0%***
						8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	7.1%	***7.5%***	***8.5%***	Return on Shr. Equity	***9.0%***
						8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	12.0%	7.4%	***8.5%***	***10.0%***	Return on Com Equity	***11.0%***
						3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.0%	2.8%	***3.5%***	***4.0%***	Retained to Com Eq	***5.0%***
						61%	NMF	63%	NMF	60%	64%	67%	64%	64%	63%	***62%***	***61%***	All Div'ds to Net Prof	***55%***

CAPITAL STRUCTURE as of 3/31/24
Total Debt $12970.9 mill. **Due in 5 Yrs** $4175 mill.
LT Debt $11724.6 mill. **LT Interest** $450 mill.
(Interest cov. earned: 4.5x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $9.6 mill.
Pension Assets-12/22 $1.4 bill. **Oblig.** $1.4 bill.

Pfd Stock $486 mill. **Pfd Div'd** $42.8 mill.

Common Stock 448,305,338 shs.
as of 4/30/24
MARKET CAP: $12.9 billion (Large Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	40.8	2245.4	102.2
Other	2543.5	2254.0	1958.0
Current Assets	2584.3	4499.4	2060.2
Accts Payable	899.5	749.4	612.5
Debt Due	1791.9	3072.4	1246.3
Other	1969.1	1443.3	1266.2
Current Liab.	4660.5	5265.1	3125.0
Fix. Chg. Cov.	255%	225%	425%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-5.0%	-3.5%	*5.5%*
"Cash Flow"	.5%	6.5%	*5.5%*
Earnings	1.5%	15.0%	*9.5%*
Dividends	-.5%	3.5%	*4.5%*
Book Value	-3.0%	.5%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	1183.2	1089.5	1704.6	5850.6
2023	1966.0	1090.0	1027.4	1422.0	5505.4
2024	1706.3	***1400***	***1200***	***1893.7***	***6200***
2025	***1805***	***1480***	***1270***	***1995***	***6550***

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.77	.13	.11	.39	1.37
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	.53	1.60
2024	.85	***.15***	***.13***	***.57***	***1.70***
2025	***.90***	***.20***	***.15***	***.60***	***1.85***

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265	.265			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 488,833 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2024: electrical, 32%; gas, 67%; other, less than 1%. Generating capacity, coal, 69.4%; purchased & other, 30.6%. 2022 reported depreciation rates: 3.5% electric, 2.4% gas. Has 7,364 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource had a strong earnings performance in the first quarter of 2024. The company continued its streak of consecutive quarterly growth by posting earnings of $0.85 per share, a 10% increase from the previous year. While this matched our target, the metric shows an outperformance considering the significant expansion of the number of diluted shares outstanding in the quarter, which we did not anticipate. The shares were likely issued in response to a large portion of debt that came due in the quarter, reflecting the utility's challenge of financing in the current high interest-rate environment. Still, investment is critical for the company's growth. Fortunately, the utility enjoys a strong regulatory environment across its geographies in Indiana, Ohio, Pennsylvania and Virginia, which together contributed to a rate-base of $18.8 billion at the end of 2023.

Our near-term earnings targets remain unchanged at the current juncture. Year-end earnings per share of $1.70 is likely, due to our anticipation of rate-base growth of roughly 8%-10%. The company has plans for significant capital expansion, including $16.4 billion aimed at enhancing system reliability and the transition to more sustainable energy sources. NiSource's track record for efficient capital allocation has led to consistent regulatory execution and affordable energy for its customers, supporting a low operating-risk profile. Too, tailwinds from sustainable investments, such as solar projects and infrastructure hardening, are likely to synergize with trends within the mid-west, such as the reshoring of manufacturing and the increasing development of data centers within its operating footprint. Economic conditions permitting, we anticipate steady earnings growth through to late decade.

Our stock projections reflect NiSource's strong prospects. Despite a strong return of more than 12% over the past three months, these good quality shares still reflect appealing value to the risk-sensitive accounts. The stock's high marks for Price Stability (95) pair well with it's above-average dividend yield of 3.8% to create a strong offering to income-style conservative investors.

Earl B. Humes *May 24, 2024*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due early August. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '23: $1485.9 million, $3.33/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	60

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N.W. NATURAL NYSE-NWN

RECENT PRICE 38.48 | P/E RATIO 15.4 (Trailing: 16.9 Median: 24.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 5.1% | VALUE LINE

TIMELINESS 3 Raised 3/22/24
SAFETY 2 Raised 2/23/24
TECHNICAL 4 Raised 5/17/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

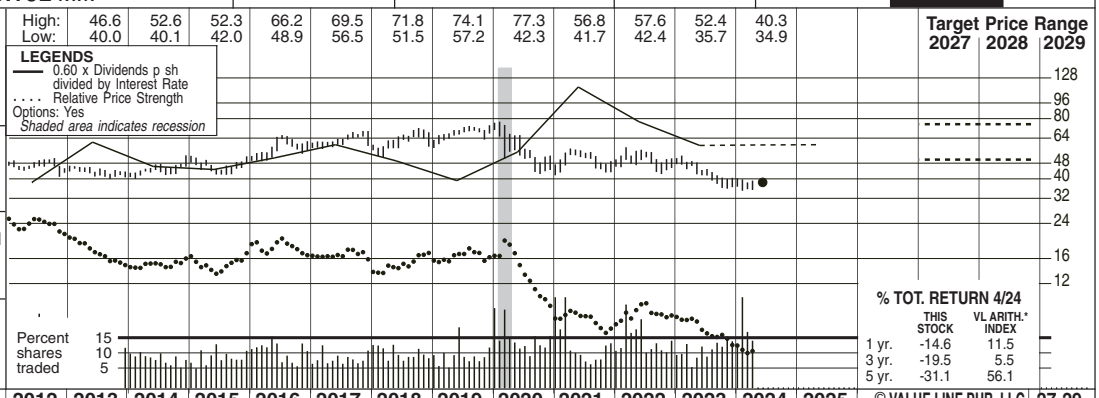
Low-High	Midpoint (% to Mid)
$33-$54	$44 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+95%)	*22%*
Low	50	(+30%)	*11%*

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	122	115	123
to Sell	123	110	90
Hld's(000)	26926	27474	28414



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	31.82	*29.50*	*29.25*	Revenues per sh	*31.25*
5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	5.83	*5.85*	*6.65*	"Cash Flow" per sh	*7.20*
2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.59	*2.50*	*3.00*	Earnings per sh A	*3.20*
1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	*1.95*	*1.96*	Div'ds Decl'd per sh B■	*1.98*
3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	8.70	*9.25*	*9.50*	Cap'l Spending per sh	*10.00*
23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.08	34.12	*36.55*	*36.60*	Book Value per sh D	*36.10*
26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	37.63	*39.00*	*41.00*	Common Shs Outst'g C	*45.00*
18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	16.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*20.0*
1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.06	1.13	.96			Relative P/E Ratio	*1.10*
3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%			Avg Ann'l Div'd Yield	*3.3%*
754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1197.5	*1150*	*1200*	Revenues ($mill)	*1400*
58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	93.9	*97.5*	*125*	Net Profit ($mill)	*145*
41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	25.7%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	7.8%	*8.5%*	*10.3%*	Net Profit Margin	*10.2%*
44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	52.6%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	47.4%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2709.2	*2850*	*3000*	Total Capital ($mill)	*3250*
2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3358.0	*3500*	*3675*	Net Plant ($mill)	*3900*
5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	3.6%	3.5%	*3.5%*	*4.0%*	Return on Total Cap'l	*4.5%*
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*7.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*7.0%*	*8.0%*	Return on Com Equity	*9.0%*
1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.1%	1.7%	*1.5%*	*3.0%*	Retained to Com Eq	*3.5%*
85%	92%	87%	NMF	76%	82%	79%	71%	79%	75%	*78%*	*65%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $1670.3 mill. **Due in 5 Yrs** $1415 mill.
LT Debt $1574.7 mill. **LT Interest** $80 mill.

(Total interest coverage: 5.0x)

Pension Assets-12/23 $283.0 mill.
Oblig. $425.5 mill.

Pfd Stock None

Common Stock 38,028,137 shares
as of 4/26/24

MARKET CAP $1.5 billion (Small Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	29.3	32.9	72.4
Other	714.9	568.5	465.3
Current Assets	744.2	601.4	537.7
Accts Payable	180.7	145.4	107.9
Debt Due	348.9	240.7	95.6
Other	369.1	310.8	264.8
Current Liab.	898.7	696.9	468.3
Fix. Chg. Cov.	320%	240%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-2.5%	- -	*4.5%*
"Cash Flow"	1.0%	2.5%	*5.0%*
Earnings	-1.0%	2.5%	*6.5%*
Dividends	1.5%	.5%	*.5%*
Book Value	1.0%	.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	355.7	1197.5
2024	433.5	*220*	*130*	*366.5*	*1150*
2025	*450*	*230*	*135*	*385*	*1200*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	1.21	2.59
2024	1.69	*.05*	*d.65*	*1.41*	*2.50*
2025	*2.10*	*.05*	*d.60*	*1.45*	*3.00*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488	.488			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 38%; commercial, 23%; industrial, gas transportation, 39%. Employs 1,380. BlackRock Inc. owns 17.6% of shares; Vanguard, 12.4%; Off./Dir., .84% (4/24 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Holdings continues to face challenging earnings comparisons. The northwestern natural gas utility saw its earnings decrease year-over-year for the fourth consecutive quarter in the March period to start 2024. Earnings per share in the company's cyclical-peak season amounted to $1.69, well below our target for a flat performance versus the year-prior's $2.01 result. The downturn in performance was primarily due to regulatory lag effects on its capital investments and rising cost pressures resulting in higher pension, depreciation, and interest expenses. Despite this, strengths such as a 1.7% growth in its customer base, low regional unemployment, and a peak-day delivery record of 8 million thermal units, paint an backdrop of strong demand. However, we expect that cost-of-living concerns across its operating footprint have led regulators to scrutinize the company's filings and tighten up on the rate-base regulatory approval process, hampering results of late.

We've cut our near-term earnings target to reflect the likelihood of continued regulatory challenges. While underlying operations should continue to grow steadily based on demographic trends, profitability leading into the cyclical-low season is likely to underwhelm. Instead, the company is refocusing its efforts on infrastructure hardening, including a planned $82 million investment that is slated for the current year as part of its rate case filings. We expect a relief in the final stanza of the year with rate adjustments likely to be resolved by November.

The long-term outlook here is more nuanced. Northwest is positioned in a strong geographic market that is undergoing a heavy investment cycle into clean-energy and energy-efficiency initiatives that ought to provide ample tailwinds to late decade. However, we also note some potential risks as both wildfires and seismic events have the potential to cause impairment to the company's infrastructure.

These good quality shares offer solid return potential and an above average dividend. The stock is a strong pick for conservative accounts, due to its Price Stability (85) and Financial Strength (A).

Earl B. Humes *May 24, 2024*

(A) Diluted earnings per share. Excludes nonrecurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early August.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2023: $163 million, $4.33/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	15

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ONE GAS, INC. NYSE-OGS

RECENT PRICE 63.81 | P/E RATIO 16.0 (Trailing: 15.8 Median: 21.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 12/8/23
SAFETY 2 New 6/2/17
TECHNICAL 3 Raised 5/24/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

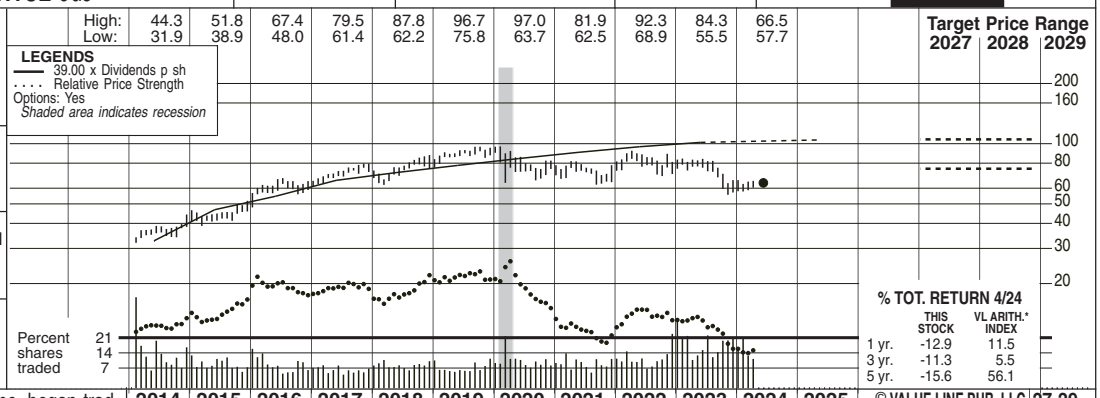
Low-High	Midpoint (% to Mid)
$42-$77	$60 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+65%)	*16%*
Low	75	(+20%)	*8%*

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	158	148	159
to Sell	133	153	160
Hld's(000)	53044	51074	52932



The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

CAPITAL STRUCTURE as of 3/31/24
Total Debt $3128.0 mill. **Due in 5 Yrs** $890.0 mill.
LT Debt $2146.4 mill. **LT Interest** $120.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x)
Leases, Uncapitalized Annual rentals $6.7 mill.
Pfd Stock None
Pension Assets-12/23 $977.0 mill.
Oblig. $962.1 mill.
Common Stock 56,569,396 shs.
as of 4/29/24
MARKET CAP: $3.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	9.7	18.8	11.5
Other	1207.9	746.4	652.2
Current Assets	1217.6	765.2	663.7
Accts Payable	360.5	278.1	196.6
Debt Due	572.7	888.9	981.6
Other	256.2	310.2	225.3
Current Liab.	1189.4	1477.2	1403.5
Fix. Chg. Cov.	540%	390%	420%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	- -	7.0%	*9.5%*
"Cash Flow"	- -	7.0%	*9.0%*
Earnings	- -	6.0%	*3.5%*
Dividends	- -	8.5%	*2.5%*
Book Value	- -	4.5%	*4.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	606.0	2372.0
2024	758.3	*410*	*350*	*701.7*	*2220*
2025	*800*	*430*	*410*	*760*	*2400*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.79	.56	.38	1.12	3.85
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	1.27	4.14
2024	1.75	*.56*	*.43*	*1.26*	*4.00*
2025	*1.85*	*.60*	*.48*	*1.27*	*4.20*

Calendar	QUARTERLY DIVIDENDS PAID [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66	.66			

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
	34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	41.95	*39.30*	*42.50*	Revenues per sh	*70.15*
	4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	9.04	*9.65*	*10.70*	"Cash Flow" per sh	*13.95*
	2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	4.14	*4.00*	*4.20*	Earnings per sh [A]	*5.00*
	.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	*2.64*	*2.68*	Div'ds Decl'd per sh [B■]	*2.85*
	5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	11.79	*11.95*	*12.15*	Cap'l Spending per sh	*12.60*
	34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	48.91	*50.15*	*53.55*	Book Value per sh	*60.20*
	52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	56.55	*56.50*	*56.50*	Common Shs Outst'g [C]	*57.00*
	17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	18.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
	.94	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.16	1.01			Relative P/E Ratio	*1.00*
	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%			Avg Ann'l Div'd Yield	*3.2%*
	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	2372.0	*2220*	*2400*	Revenues ($mill)	*4000*
	109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	231.2	*225*	*235*	Net Profit ($mill)	*285*
	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	14.9%	*15.5%*	*16.0%*	Income Tax Rate	*20.0%*
	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	9.7%	*10.1%*	*9.8%*	Net Profit Margin	*7.1%*
	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	43.8%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*51.0%*
	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	56.2%	*55.0%*	*55.0%*	Common Equity Ratio	*49.0%*
	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	4926.3	*5150*	*5500*	Total Capital ($mill)	*7000*
	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	6135.2	*6425*	*6800*	Net Plant ($mill)	*8000*
	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	5.9%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	*8.0%*	*8.0%*	Return on Com Equity	*8.5%*
	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	3.2%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
	40%	53%	52%	55%	56%	56%	58%	60%	60%	62%	*66%*	*64%*	All Div'ds to Net Prof	*57%*

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 160 Bcf of natural gas supply in 2023, compared to 165 Bcf in 2022. Total volumes delivered by customer (fiscal 2023): transportation, 59.3%; residential, 29.7%; commercial & industrial, 10.6%; other, .4%. ONE Gas has around 3,900 employees. BlackRock owns 14.5% of common stock; The Vanguard Group, 11.6%; American Century Investment, 7.5%; officers and directors, 1.5% (4/24 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. began 2024 in low gear. First-quarter earnings per share slipped about 5%, to $1.75, relative to last year's $1.84 figure. That was traced partly to higher employee-related costs, given planned investments in the company's workforce and ongoing in-sourcing efforts. Also, sales volumes decreased and interest expense rose. But new rates did provide somewhat of an offset. Still, right now, it appears that the bottom line will recede around 3% for the whole year, to $4.00 per share, versus the $4.14 tally generated in 2023. But turning to 2025, a 5% recovery, to $4.20 a share, seems plausible. That's based, to a certain degree, on our assumption that the business environment is generally favorable.

Prospects out to the end of the decade appear promising. ONE Gas remains the top natural gas distributor, as measured by number of customers, in both Oklahoma and Kansas, and holds the number-three position in Texas. (Services are provided to more than two million residential, commercial, and transportation clients at present.) Furthermore, we believe those markets have decent growth potential and are located in one of the most active drilling areas in the United States. Also, supported by the solid balance sheet, the company ought to continue to meet its working capital requirements, capital expenditures, and other obligations with little difficulty.

There are risk factors to bear in mind, however. ONE Gas' lack of geographic diversification leaves it somewhat more susceptible to regional economic downturns and regulations. Moreover, there's competition from other energy suppliers, including propane dealers and electric companies. Finally, pipeline ruptures, leaks, and other unfortunate occurrences can take a major toll on corporate profits if not adequately covered by insurance.

The stock has some investment appeal. Its dividend yield is respectable in comparison with other equities within *Value Line's* Natural Gas Utility Industry. Also, capital appreciation possibilities over the 2027-2029 horizon look worthwhile. Consider, too, the 2 (Above Average) rank for Safety and high Price Stability score of 90 out of 100.

Frederick L. Harris, III *May 24, 2024*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Aug. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	100

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SPIRE INC. NYSE-SR

RECENT PRICE **62.20** | P/E RATIO **14.5** (Trailing: 15.7 Median: 19.0) | RELATIVE P/E RATIO **0.80** | DIV'D YLD **5.0%** | **VALUE LINE**

TIMELINESS 3 Raised 2/16/24
SAFETY 2 Raised 6/20/03
TECHNICAL 4 Raised 5/17/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

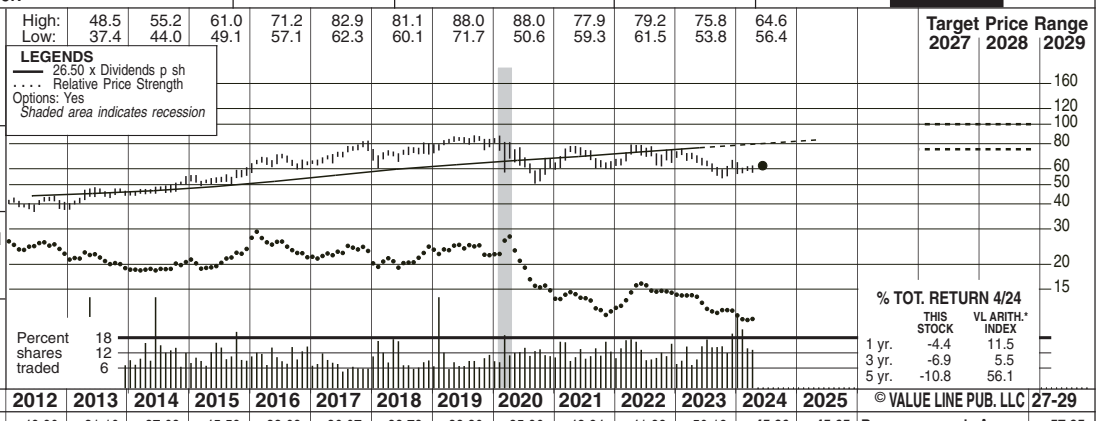
Low-High	Midpoint (% to Mid)
$44-$72	$58 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+60%)	*16%*
Low	75	(+20%)	*10%*

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	142	131	140
to Sell	138	144	123
Hld's(000)	46098	48374	48459



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	50.12	*45.20*	*45.65*	Revenues per sh A	*57.25*
4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	8.60	*8.80*	*9.25*	"Cash Flow" per sh	*11.00*
2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	3.85	*4.30*	*4.55*	Earnings per sh A B	*5.50*
1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	*3.02*	*3.16*	Div'ds Decl'd per sh C■	*3.60*
2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	12.45	*13.70*	*13.90*	Cap'l Spending per sh	*14.50*
22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	50.29	*52.65*	*55.75*	Book Value per sh D	*66.05*
21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	53.20	*58.50*	*60.00*	Common Shs Outst'g E	*62.00*
14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	17.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	1.00			Relative P/E Ratio	*.90*
3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%			Avg Ann'l Div'd Yield	*4.1%*
1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	2666.3	*2645*	*2740*	Revenues ($mill) A	*3550*
84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	217.5	*240*	*260*	Net Profit ($mill)	*340*
27.6%	31.2%	32.5%	32.4%	- -	15.7%	12.3%	20.1%	21.1%	15.1%	*19.5%*	*19.5%*	Income Tax Rate	*24.0%*
5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	8.2%	*9.1%*	*9.5%*	Net Profit Margin	*9.6%*
55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	54.9%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*51.0%*
44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	41.3%	*44.0%*	*44.0%*	Common Equity Ratio	*45.0%*
3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	6471.3	*7000*	*7600*	Total Capital ($mill)	*9100*
2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	5778.9	*6150*	*6530*	Net Plant ($mill)	*7675*
3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	4.8%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	7.5%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	7.6%	*8.0%*	*8.0%*	Return on Com Equity	*8.5%*
1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	1.9%	*2.0%*	*1.5%*	Retained to Com Eq	*2.5%*
73%	58%	59%	60%	51%	66%	NMF	54%	71%	76%	*77%*	*79%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $4514.4 mill. **Due in 5 Yrs**$2310.0 mill.
LT Debt $3421.4 mill. **LT Interest** $140.0 mill.
(Total interest coverage: 2.4x)

Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-9/23 $630.3 mill.
Oblig. $832.5 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 57,747,978 shs.
as of 4/28/24

MARKET CAP: $3.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	6.5	5.6	25.6
Other	1585.5	1071.3	980.1
Current Assets	1592.0	1076.9	1005.7
Accts Payable	617.4	253.1	193.4
Debt Due	1318.7	1112.1	1093.0
Other	417.5	390.2	363.9
Current Liab.	2353.6	1755.4	1650.3
Fix. Chg. Cov.	393%	294%	315%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	4.5%	*4.0%*
"Cash Flow"	8.0%	5.0%	*4.0%*
Earnings	5.0%	3.0%	*4.5%*
Dividends	5.0%	5.5%	*4.5%*
Book Value	5.5%	3.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	310.4	2666.3
2024	756.6	1128.5	*434.9*	*325*	*2645*
2025	*790*	*1135*	*465*	*350*	*2740*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	d.66	3.85
2024	1.52	3.58	*d.34*	*d.46*	*4.30*
2025	*1.50*	*3.45*	*d.16*	*d.24*	*4.55*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	2.88
2024	.755	.755			

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2023: 3.2 bill. Revenue mix for regulated operations: residential, 67%; commercial and industrial, 25%; transportation, 5%; other, 3%. Officers and directors own 2.9% of common shares; American Century Companies, 15.4% (12/23 proxy). Chairman: Edward Glotzbach; CEO: Steve Lindsey. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire managed to post decent bottom-line results in the second quarter of fiscal 2024 (which concluded on March 31st). Indeed, earnings per share of $3.58 were 7.5% above the previous year's $3.33 tally. That was brought about, to a certain extent, by the Gas Utility division, which benefited partly from improved results at Spire Alabama. The Gas Marketing segment had a better showing for that period, too.

Higher profits appear to be in store for the year as a whole, as well. The company did get off to a slow start, with first-quarter share net receding 8.4%, to $1.52, relative to last year's $1.66 figure. That was attributed partly to the fact that, for both the Gas Marketing and Midstream divisions, fiscal 2023's very favorable market conditions did not reoccur. But, as mentioned, Spire's second-quarter performance was decent. Furthermore, bottom-line comparisons during the second half ought to be easier. (Losses are typical over that time frame because of the seasonality of the business.) All told, we expect full-year share net to rebound about 12%, to $4.30, versus fiscal 2023's $3.85 result. Concerning next year, profits might increase another 6% or so, to $4.55 a share, assuming additional widening of operating margins.

The Financial Strength rating sits at B++. When the second quarter ended, cash and equivalents were $25.6 million. Furthermore, there was $1.3 billion available through a revolving credit facility expiring in July, 2027. Also, long-term debt resided at a manageable 50% of total capital, and short-term obligations of almost $1.1 billion did not seem to be a major obstacle. So, the company should continue to satisfy its commitments, which include working capital requirements and capital expenditures, with minimal difficulty.

The equity ought to draw the attention of some investors. Its dividend yield stacks up well compared to those of other stocks in *Value Line's* Natural Gas Utility Industry. What's more, capital appreciation potential over the 2027-2029 horizon looks worthwhile. Meanwhile, SR shares are pegged to mimic the market over the next six to 12 months (Timeliness rank 3: Average).

Frederick L. Harris, III *May 24, 2024*

(A) Fiscal year ends Sept. 30th. **(B)** Based on diluted shares outstanding. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. **(C)** Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. **(D)** Incl. deferred charges. In '23: $1,171.6 mill., $22.02/sh. **(E)** In millions. **(F)** Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	45

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Atmos Energy Corporation
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Six Natural Gas Distribution Companies	Proxy Group of Six Natural Gas Distribution Companies (excl. PRPM)
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.09 %	5.09 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds	0.50 (2)	0.50 (2)
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.59 %	5.59 %
4.	Equity Risk Premium (3)	5.21	5.16
5.	Risk Premium Derived Common Equity Cost Rate	10.80 %	10.75 %

Notes:
(1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 7 and 8 of this Schedule).
(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.50% from page 2 of this Schedule.
(3) From page 5 of this Schedule.

Atmos Energy Corporation
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields - Moody's

	[1] Aaa Rated Corporate Bond	[2] Aa Rated Public Utility Bond	[3] A2 Rated Public Utility Bond	[4] Baa2 Rated Public Utility Bond
Jul-2024	5.04 %	5.46 %	5.57 %	5.77 %
Jun-2024	5.13	5.50	5.61	5.84
May-2024	5.25	5.62	5.74	5.97
Average	5.14 %	5.53 %	5.64 %	5.86 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds: 0.50 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds: 0.22 % (2)

A2 Rated Public Utility Bonds Over Aa2 Rated Public Utility Bonds: 0.11 % (3)

Notes:
(1) Column [3] - Column [1].
(2) Column [4] - Column [3].
(3) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Service

Atmos Energy Corporation
Comparison of Long-Term Issuer Ratings for
Proxy Group of Six Natural Gas Distribution Companies

	Moody's		Standard & Poor's	
	Long-Term Issuer Rating		Long-Term Issuer Rating	
	July 2024		July 2024	
Proxy Group of Six Natural Gas Distribution Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Spire Inc.	A1/A2	5.5	BBB+	8.0
Average	A2	6.4	A-	7.0

Notes:

(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 4 of this Schedule.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Atmos Energy Corporation
Judgment of Equity Risk Premium for
Proxy Group of Six Natural Gas Distribution Companies

Line No.		Proxy Group of Six Natural Gas Distribution Companies	Proxy Group of Six Natural Gas Distribution Companies (excl. PRPM)
1.	Calculated equity risk premium based on the total market using the beta approach (1)	6.08 %	6.00 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	4.73	4.65
3.	Predicted Equity Risk Premium Based on Regression Analysis of 836 Fully-Litigated Natural Gas Utility Rate Cases (3)	4.82	4.82
4.	Average equity risk premium	5.21 %	5.16 %

Notes: (1) From page 6 of this Schedule.
(2) From page 9 of this Schedule.
(3) From page 10 of this Schedule.

Atmos Energy Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Six Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Six Natural Gas Distribution Companies	Proxy Group of Six Natural Gas Distribution Companies (excl. PRPM)
1.	Ibbotson Equity Risk Premium (1)	5.96 %	5.96 %
2.	Regression on Ibbotson Risk Premium Data (2)	6.98	6.98
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.11	NA
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	7.15	7.15
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Capital IQ S&P 500 Companies (5)	10.33	10.33
6.	Conclusion of Equity Risk Premium	7.70 %	7.60 %
7.	Adjusted Beta (6)	0.79	0.79
8.	Forecasted Equity Risk Premium	6.08 %	6.00 %

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll 2023 SBBI® Yearbook and Bloomberg Professional Services minus the arithmetic mean monthly yield of Moody's average Aaa and Aa2 corporate bonds from 1928-2023.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2023 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 5.09% (from page 1 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through July 2024.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.09% (from page 1 of this Schedule) from the projected 3-5 year total annual market return of 12.24% (described fully in note 1 on page 2 of Schedule DWD-4).

(5) Using data from the Bloomberg Professional Services, Value Line, and S&P Capital IQ for the S&P 500 for the S&P 500, an expected total return of 15.42% was derived based upon expected dividend yields as a proxy for income returns and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.09% results in an expected equity risk premium of 10.33%.

(6) Average of mean and median beta from Schedule DWD-4.

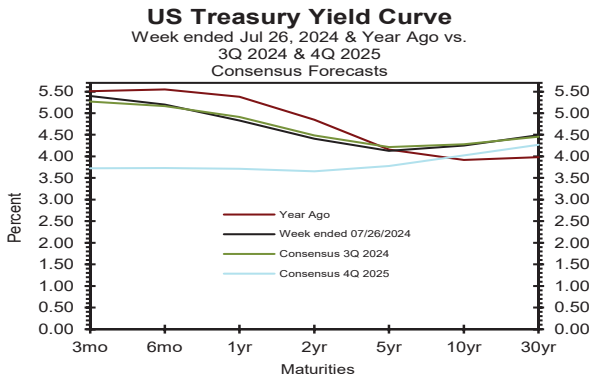
Sources of Information:

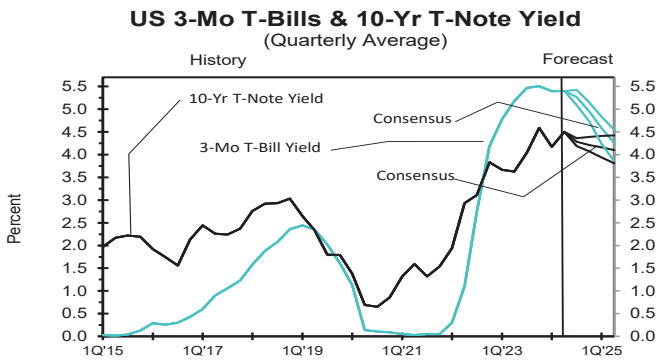
Kroll 2023 SBBI® Yearbook
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, August 1, 2024 and May 31, 2024
Bloomberg Professional Service
S&P Capital IQ

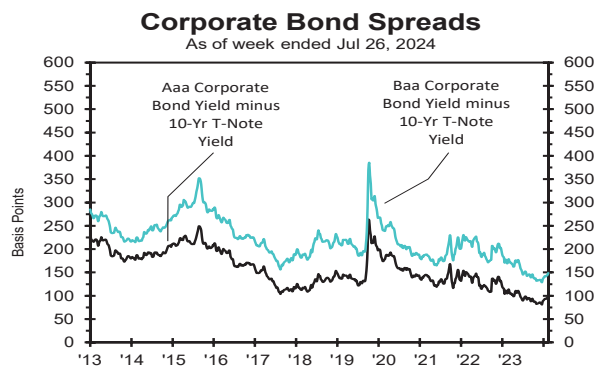
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

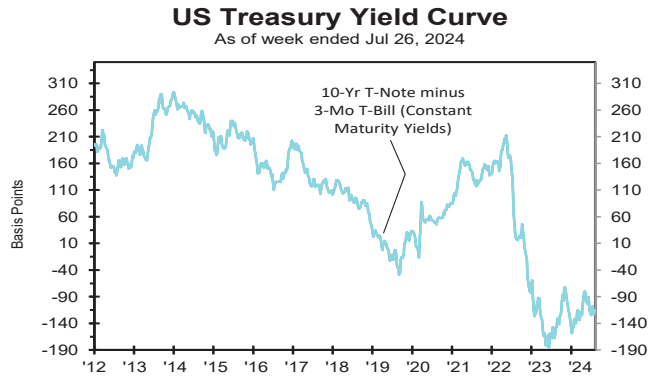
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	3Q	4Q	1Q	2Q	3Q	4Q
Interest Rates	Jul 26	Jul 19	Jul 12	Jul 5	Jun	May	Apr	2Q 2024	2024	2024	2025	2025	2025	2025
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	**5.3**	**5.0**	**4.7**	**4.4**	**4.1**	**3.9**
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	**8.4**	**8.1**	**7.8**	**7.5**	**7.2**	**7.0**
SOFR	5.34	5.34	5.34	5.35	5.33	5.31	5.32	5.32	**5.3**	**5.0**	**4.7**	**4.4**	**4.1**	**3.8**
Commercial Paper, 1-mo.	5.29	5.30	5.30	5.31	5.31	5.32	5.31	5.31	**5.2**	**5.0**	**4.6**	**4.3**	**4.0**	**3.7**
Treasury bill, 3-mo.	5.40	5.43	5.45	5.47	5.51	5.46	5.44	5.47	**5.3**	**5.0**	**4.6**	**4.3**	**3.9**	**3.7**
Treasury bill, 6-mo.	5.20	5.23	5.30	5.36	5.37	5.42	5.38	5.39	**5.2**	**4.9**	**4.5**	**4.2**	**3.9**	**3.7**
Treasury bill, 1 yr.	4.83	4.86	4.96	5.05	5.11	5.16	5.14	5.14	**4.9**	**4.6**	**4.4**	**4.1**	**3.9**	**3.7**
Treasury note, 2 yr.	4.41	4.45	4.56	4.71	4.74	4.86	4.87	4.82	**4.5**	**4.3**	**4.1**	**3.9**	**3.7**	**3.7**
Treasury note, 5 yr.	4.13	4.11	4.19	4.35	4.32	4.50	4.56	4.46	**4.2**	**4.1**	**4.0**	**3.9**	**3.8**	**3.8**
Treasury note, 10 yr.	4.25	4.20	4.25	4.39	4.31	4.48	4.54	4.44	**4.3**	**4.2**	**4.2**	**4.1**	**4.1**	**4.0**
Treasury note, 30 yr.	4.49	4.41	4.44	4.56	4.44	4.62	4.66	4.57	**4.5**	**4.4**	**4.4**	**4.3**	**4.3**	**4.3**
Corporate Aaa bond	5.25	5.16	5.20	5.32	5.21	5.33	5.38	5.31	**5.1**	**5.1**	**5.1**	**5.0**	**5.0**	**5.0**
Corporate Baa bond	5.74	5.65	5.69	5.81	5.70	5.81	5.88	5.80	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**
State & Local bonds	4.16	4.15	4.20	4.26	4.24	4.28	4.28	4.27	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**
Home mortgage rate	6.78	6.77	6.89	6.95	6.92	7.06	6.99	6.99	**6.8**	**6.6**	**6.5**	**6.3**	**6.2**	**6.1**
	History								Consensus Forecasts-Quarterly					
	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q
Key Assumptions	2022	2022	2023	2023	2023	2023	2024	2024	2024	2024	2025	2025	2025	2025
Fed's AFE $ Index	118.8	119.8	115.5	114.6	115.0	116.6	115.5	117.3	**116.7**	**116.8**	**116.3**	**116.1**	**115.9**	**115.8**
Real GDP	2.7	2.6	2.2	2.1	4.9	3.4	1.4	2.8	**1.8**	**1.6**	**1.8**	**1.9**	**2.0**	**2.1**
GDP Price Index	4.4	3.9	3.9	1.7	3.3	1.6	3.1	2.3	**2.3**	**2.3**	**2.3**	**2.2**	**2.2**	**2.1**
Consumer Price Index	5.3	4.0	3.8	3.0	3.4	2.7	3.8	2.8	**2.3**	**2.5**	**2.4**	**2.3**	**2.3**	**2.3**
PCE Price Index	4.7	4.1	4.2	2.5	2.6	1.8	3.4	2.6	**2.2**	**2.2**	**2.3**	**2.1**	**2.1**	**2.2**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).









Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2025 through 2030 and averages for the five-year periods 2026-2030 and 2031-2035. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year						Five-Year Averages	
		2025	2026	2027	2028	2029	2030	2026-2030	2031-2035
1. Federal Funds Rate	**CONSENSUS**	**4.1**	**3.4**	**3.2**	**3.2**	**3.3**	**3.3**	**3.3**	**3.2**
	Top 10 Average	4.5	3.8	3.8	3.8	3.8	3.8	3.8	3.8
	Bottom 10 Average	3.6	3.0	2.7	2.7	2.7	2.7	2.8	2.7
2. Prime Rate	**CONSENSUS**	**7.1**	**6.5**	**6.4**	**6.4**	**6.4**	**6.3**	**6.4**	**6.3**
	Top 10 Average	7.5	6.9	6.9	6.9	6.9	6.9	6.9	6.8
	Bottom 10 Average	6.8	6.1	5.9	5.8	5.8	5.7	5.9	5.7
3. SOFR	**CONSENSUS**	**4.0**	**3.4**	**3.3**	**3.3**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	4.3	3.7	3.7	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.8	3.1	2.9	2.8	2.8	2.7	2.8	2.7
4. Commercial Paper, 1-Mo	**CONSENSUS**	**4.0**	**3.4**	**3.4**	**3.3**	**3.3**	**3.3**	**3.4**	**3.3**
	Top 10 Average	4.2	3.6	3.6	3.6	3.5	3.5	3.6	3.6
	Bottom 10 Average	3.8	3.2	3.0	3.0	3.0	2.9	3.0	2.9
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**4.0**	**3.4**	**3.3**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**
	Top 10 Average	4.4	3.7	3.7	3.7	3.7	3.7	3.7	3.7
	Bottom 10 Average	3.6	3.0	2.8	2.7	2.7	2.7	2.8	2.6
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**4.0**	**3.5**	**3.4**	**3.4**	**3.4**	**3.3**	**3.4**	**3.3**
	Top 10 Average	4.3	3.8	3.8	3.7	3.7	3.7	3.8	3.7
	Bottom 10 Average	3.7	3.2	3.0	2.9	2.9	2.8	3.0	2.8
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**4.0**	**3.6**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	**3.4**
	Top 10 Average	4.3	3.9	3.9	3.9	3.9	3.9	3.9	3.8
	Bottom 10 Average	3.8	3.4	3.2	3.1	3.0	3.0	3.1	3.0
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.8**	**3.7**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**
	Top 10 Average	4.1	4.0	4.1	4.1	4.1	4.1	4.1	4.1
	Bottom 10 Average	3.5	3.3	3.2	3.1	3.1	3.1	3.2	3.0
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.9**	**3.8**	**3.8**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
	Top 10 Average	4.2	4.2	4.3	4.3	4.5	4.4	4.3	4.5
	Bottom 10 Average	3.6	3.5	3.4	3.3	3.4	3.4	3.4	3.3
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**4.0**	**4.0**	**4.0**	**4.0**	**4.2**	**4.2**	**4.1**	**4.2**
	Top 10 Average	4.4	4.5	4.5	4.6	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.7	3.6	3.5	3.5	3.6	3.6	3.5	3.6
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.2**	**4.2**	**4.2**	**4.3**	**4.4**	**4.4**	**4.3**	**4.4**
	Top 10 Average	4.5	4.6	4.7	4.8	4.9	4.9	4.7	4.9
	Bottom 10 Average	3.9	3.9	3.8	3.8	3.8	3.9	3.8	3.8
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.1**	**5.1**	**5.1**	**5.2**	**5.3**	**5.3**	**5.2**	**5.2**
	Top 10 Average	5.4	5.4	5.6	5.7	5.8	5.8	5.7	5.8
	Bottom 10 Average	4.8	4.7	4.7	4.7	4.7	4.7	4.7	4.7
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.0**	**6.1**	**6.1**	**6.2**	**6.2**	**6.1**	**6.2**
	Top 10 Average	6.3	6.3	6.5	6.6	6.7	6.7	6.5	6.7
	Bottom 10 Average	5.7	5.7	5.6	5.6	5.6	5.7	5.6	5.7
14. State & Local Bonds Yield	**CONSENSUS**	**4.1**	**4.1**	**4.2**	**4.2**	**4.3**	**4.4**	**4.2**	**4.3**
	Top 10 Average	4.4	4.5	4.5	4.6	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.7
15. Home Mortgage Rate	**CONSENSUS**	**6.3**	**6.1**	**6.1**	**6.1**	**6.1**	**6.2**	**6.1**	**6.1**
	Top 10 Average	6.7	6.5	6.5	6.5	6.6	6.6	6.6	6.6
	Bottom 10 Average	6.0	5.7	5.7	5.6	5.6	5.6	5.6	5.5
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**115.6**	**114.6**	**114.3**	**113.9**	**113.4**	**112.8**	**113.8**	**112.3**
	Top 10 Average	116.9	116.3	115.8	115.7	115.3	115.1	115.6	114.8
	Bottom 10 Average	114.2	113.0	112.7	112.1	111.5	110.9	112.0	110.1
		Year-Over-Year, % Change						Five-Year Averages	
		2025	2026	2027	2028	2029	2030	2026-2030	2031-2035
B. Real GDP	**CONSENSUS**	**1.9**	**2.0**	**2.1**	**2.1**	**2.0**	**2.0**	**2.1**	**2.0**
	Top 10 Average	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.2
	Bottom 10 Average	1.6	1.8	1.9	1.8	1.8	1.8	1.8	1.8
C. GDP Chained Price Index	**CONSENSUS**	**2.3**	**2.2**	**2.2**	**2.1**	**2.2**	**2.1**	**2.2**	**2.1**
	Top 10 Average	2.6	2.4	2.4	2.3	2.3	2.3	2.4	2.3
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.7	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	Bottom 10 Average	2.1	2.1	2.0	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.2
	Bottom 10 Average	2.0	1.9	1.9	1.9	2.0	2.0	1.9	2.0

Atmos Energy Corporation
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.	Equity Risk Premium Measure	Implied Equity Risk Premium	Implied Equity Risk Premium excl. PRPM
1.	Historical Equity Risk Premium (1)	4.02 %	4.02 %
2.	Regression of Historical Equity Risk Premium (2)	4.86	4.86
3.	Forecasted Equity Risk Premium Based on PRPM (3)	4.98	NA
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg, Value Line, and S&P Capital IQ Data) (4)	5.08	5.08
5.	Average Equity Risk Premium (5)	4.73 %	4.65 %

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2023. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

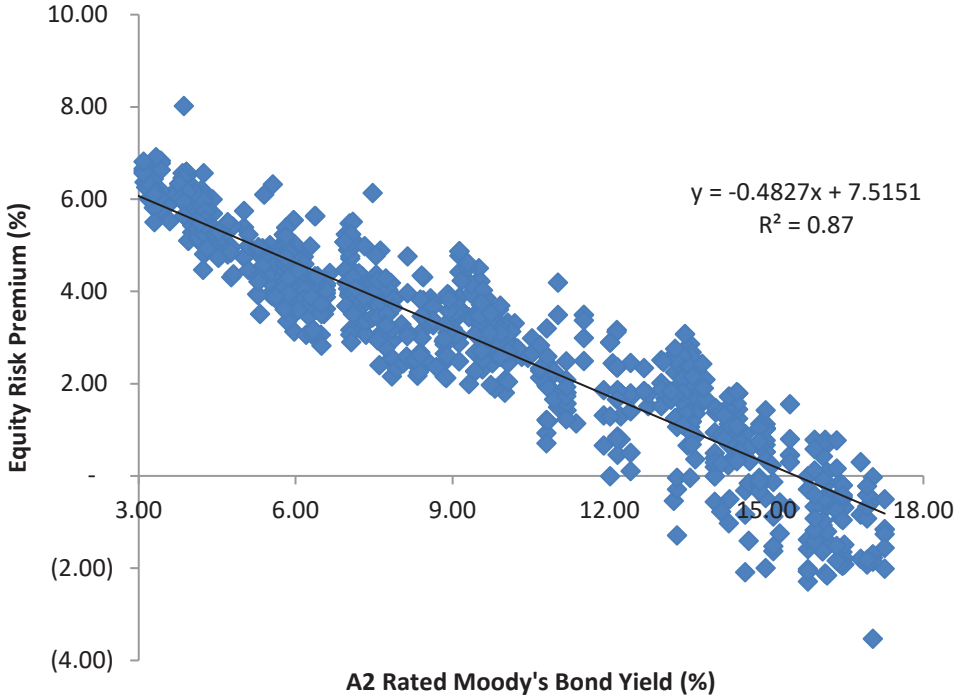
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2023 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the prospective A2 rated public utility bond yield of 5.59% (from line 3, page 1 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - July 2024.

(4) Using data from Bloomberg, Value Line, and S&P Capital IQ for the S&P Utilities Index, an expected total return of 10.67% was derived based on expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.59%, calculated on line 3 of page 1 of this Schedule results in an equity risk premium of 5.08% (10.67% - 5.59% = 5.08%).

(5) Average of lines 1 through 4.

Atmos Energy Corporation
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5151 %	-0.4827 %	5.59 %	4.82 %

Notes:

(1) From line 3 of page 1 of this Schedule.

Source of Information: Regulatory Research Associates

Atmos Energy Corporation
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Six Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost
Atmos Energy Corporation	0.85	0.69	0.77	8.63 %	4.36 %	11.00 %	11.50 %	11.25 %
New Jersey Resources Corporation	1.00	0.67	0.84	8.63	4.36	11.61	11.95	11.78
NiSource Inc.	0.95	0.66	0.81	8.63	4.36	11.35	11.76	11.55
Northwest Natural Holding Company	0.85	0.64	0.75	8.63	4.36	10.83	11.37	11.10
ONE Gas, Inc.	0.85	0.60	0.73	8.63	4.36	10.66	11.24	10.95
Spire Inc.	0.85	0.75	0.80	8.63	4.36	11.26	11.69	11.48
Mean			0.78			11.12 %	11.59 %	11.35 %
Median			0.79			11.13 %	11.60 %	11.37 %
Average of Mean and Median			0.79			11.13 %	11.60 %	11.36 %

Results Excluding the PRPM MRP

Proxy Group of Six Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost
Atmos Energy Corporation	0.85	0.69	0.77	8.52	4.36	10.92 %	11.41 %	11.17 %
New Jersey Resources Corporation	1.00	0.67	0.84	8.52	4.36	11.52	11.86	11.69
NiSource Inc.	0.95	0.66	0.81	8.52	4.36	11.26	11.67	11.47
Northwest Natural Holding Company	0.85	0.64	0.75	8.52	4.36	10.75	11.29	11.02
ONE Gas, Inc.	0.85	0.60	0.73	8.52	4.36	10.58	11.16	10.87
Spire Inc.	0.85	0.75	0.80	8.52	4.36	11.18	11.60	11.39
			0.78			11.04 %	11.50 %	11.27 %
			0.79			11.05 %	11.51 %	11.28 %
			0.79			11.05 %	11.51 %	11.28 %

Notes on page 2 of this Schedule.

Atmos Energy Corporation
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Ibbotson, Value Line, and Bloomberg as illustrated below:

Measure 1: Ibbotson Arithmetic Mean MRP (1926-2023)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2023:	12.16 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99
MRP based on Ibbotson Historical Data:	7.17 %

Measure 2: Application of a Regression Analysis to Ibbotson Historical Data (1926-2023) 7.99 %

Measure 3: Application of the PRPM to Ibbotson Historical Data: (January 1926 - July 2024) 9.04 %

Measure 4: Value Line Projected MRP (Thirteen weeks ending August 02, 2024)

Total projected return on the market 3-5 years hence*:	12.24 %
Projected Risk-Free Rate (see note 2):	4.36
MRP based on Value Line Summary & Index:	7.88 %

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Bloomberg, Value Line, and S&P Capital IQ Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	15.42 %
Projected Risk-Free Rate (see note 2):	4.36
MRP based on Value Line data	11.06 %

Average MRP:	8.63 %
Average MRP Excluding the PRPM MRP:	8.52 %

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 7 and 8 of Schedule DWD-3.) The projection of the risk-free rate is illustrated below:

Third Quarter 2024	4.50 %
Fourth Quarter 2024	4.40
First Quarter 2025	4.40
Second Quarter 2025	4.30
Third Quarter 2025	4.30
Fourth Quarter 2025	4.30
2026-2030	4.30
2031-2035	4.40
	4.36 %

(3) Average of Column 6 and Column 7.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, August 1, 2024 and May 31, 2024
Kroll 2023 SBBI® Yearbook
Bloomberg Professional Services
S&P Capital IQ

Atmos Energy Corporation
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Six Natural Gas Distribution Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of six natural gas distribution companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.65 - 0.93 and residual standard error of the regression range of 2.8139 - 3.3559 of the proxy group of six natural gas distribution companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1355. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1355 = \frac{3.08487}{\sqrt{518}} = \frac{3.08487}{22.7596}$$

Source of Information: Valueline Proprietary Database, June 2024
Value Line Investment Survey (Standard Edition).

Atmos Energy Corporation
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Six Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.85	0.76	2.9065	0.0650
New Jersey Resources Corporation	1.00	0.93	3.0807	0.0689
NiSource Inc.	0.95	0.85	2.6368	0.0590
Northwest Natural Holding Company	0.85	0.73	3.4283	0.0767
ONE Gas, Inc.	0.85	0.73	3.3343	0.0746
Spire Inc.	0.85	0.76	3.1226	0.0698
Average	0.89	0.79	3.0849	0.0690
Beta Range (+/- 2 std. Devs. of Beta)	0.65	0.93		
2 std. Devs. of Beta	0.14			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.8139	3.3559		
Std. dev. of the Res. Std. Err.	0.1355			
2 std. devs. of the Res. Std. Err.	0.2710			

Source of Information: Valueline Proprietary Database, June 2024

Atmos Energy Corporation
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

Proxy Group of Fifty-Three Non-Price Regulated Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Abbott Laboratories	0.90	0.78	0.5882	3.6744
Agilent Technologies, Inc.	0.95	0.87	0.6366	3.7888
Air Products and Chemicals, Inc.	0.90	0.84	0.5858	3.9912
Allstate Corporation (The)	1.00	0.93	0.6726	3.8517
Alphabet Inc.	0.90	0.80	0.5747	3.8945
Altria Group, Inc.	0.85	0.76	0.5978	3.5291
Analog Devices, Inc.	1.00	0.93	0.6654	3.8922
Apple Inc.	0.95	0.87	0.6071	3.9937
Archer Daniels-Midlan Company	0.95	0.90	0.6011	4.1641
Assurant Inc.	0.90	0.80	0.5958	3.7407
AutoZone Inc.	0.95	0.88	0.5941	4.1112
Booz Allen Hamilton Corporation	0.85	0.75	0.5344	3.9167
Brady Corporation	0.95	0.89	0.6317	3.9155
Brown-Forman Corporation 'B'	0.90	0.79	0.6153	3.5693
CACI International	0.90	0.80	0.5937	3.7448
Casella Waste Systems, Inc.	0.85	0.74	0.5261	3.8968
Casey's General Stores, Inc.	0.90	0.78	0.5637	3.8404
Corteva, Inc.	0.95	0.89	0.6016	4.1335
CSW Industrials	0.85	0.77	0.5478	3.9117
Danaher Corporation	0.90	0.81	0.6019	3.7531
Dolby Laboratories	0.95	0.88	0.6356	3.8441
Fastenal Company	0.90	0.78	0.5955	3.6551
GATX Corporation	0.95	0.90	0.6418	3.9176
Innospec Inc.	1.00	0.93	0.6612	3.9309
J. B. Hunt Transport Services	0.95	0.90	0.6066	4.1220
Jack Henry & Associates, Inc.	0.85	0.73	0.5397	3.7838
Juniper Networks, Inc.	0.95	0.91	0.6361	3.9835
L3Harris Technologies, Inc.	0.90	0.83	0.6055	3.8016
Lockheed Martin Corporation	0.85	0.74	0.5837	3.5162
McKesson Corporation	0.85	0.70	0.5402	3.5897
Microsoft Corporation	0.90	0.77	0.6030	3.5663
MSA Safety Incorporated	1.00	0.92	0.6398	4.0233
MSC Industrial Direct Co., Inc.	0.90	0.83	0.6116	3.7607
Oracle Corporation	0.80	0.69	0.5145	3.7587
O'Reilly Automotive, Inc.	0.90	0.83	0.6035	3.8306
OSI Systems, Inc.	0.90	0.83	0.6157	3.7364
Packaging Corporation of America	0.95	0.85	0.6382	3.7242
Pfizer, Inc.	0.80	0.68	0.4975	3.7901
Philip Morris International Inc.	0.95	0.86	0.6415	3.7276
Prestige Consumer Healthcare Inc.	0.85	0.76	0.5396	3.9247
Selective Insurance Group, Inc.	0.85	0.74	0.5652	3.6386
Sensient Technologies Corporation	0.95	0.85	0.6415	3.6843
Service Corporation International	0.95	0.85	0.5927	3.9885
Sherwin-Williams Company	0.95	0.89	0.6502	3.8205
Smith (A.O.) Corporation	0.90	0.78	0.5843	3.7307
Texas Instruments Incorporated	0.85	0.76	0.5984	3.5502
Thermo Fisher Scientific Inc.	0.85	0.76	0.5997	3.5461
UniFirst Corporation	0.90	0.80	0.6063	3.6647
UnitedHealth Group Incorporated	0.95	0.90	0.6347	3.9659
VeriSign Inc.	0.90	0.78	0.5963	3.6360
Verisk Analytics, Inc.	0.90	0.78	0.6088	3.5474
Waters Corporation	0.95	0.88	0.6070	4.0149
Watsco, Inc.	0.90	0.78	0.5601	3.8861
Average	0.91	0.82	0.5987	3.8108
Proxy Group of Six Natural Gas Distribution Companies	0.89	0.79	3.0849	0.0690

Source of Information: Valueline Proprietary Database, June 2024

Atmos Energy Corporation
Summary of Cost of Equity Models Applied to
Proxy Group of Fifty-Three Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

Principal Methods	Proxy Group of Fifty-Three Non-Price Regulated Companies	Proxy Group of Fifty-Three Non-Price Regulated Companies (excl. PRPM)
Discounted Cash Flow Model (DCF) (1)	11.29 %	11.29 %
Risk Premium Model (RPM) (2)	12.53	12.44
Capital Asset Pricing Model (CAPM)	12.11 (3)	12.02 (4)
Mean	11.98 %	11.92 %
Median	12.11 %	12.02 %
Average of Mean and Median	12.05 %	11.97 %

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.
(3) From page 6 of this Schedule.
(4) From page 7 of this Schedule.

Atmos Energy Corporation
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	
Proxy Group of Fifty-Three Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS (1)	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (2)	
Abbott Laboratories	2.11 %	4.00 %	8.60 %	8.20 %	8.45 %	7.31 %	2.19 %	9.50 %	
Agilent Technologies, Inc.	0.69	8.00	5.60	4.95	5.01	5.89	0.71	6.60	
Air Products and Chemicals, Inc.	2.69	10.50	7.40	6.58	10.43	8.73	2.81	11.54	
Allstate Corporation (The)	2.23	30.00	7.00	107.60	163.00	18.50	2.44	20.94	(3)
Alphabet Inc.	0.45	13.00	17.70	20.50	17.42	17.16	0.49	17.65	
Altria Group, Inc.	8.41	6.00	3.20	3.73	3.95	4.22	8.59	12.81	
Analog Devices, Inc.	1.61	7.50	9.50	(1.41)	4.20	7.07	1.67	8.74	
Apple Inc.	0.48	8.00	12.70	11.10	11.15	10.74	0.51	11.25	
Archer Daniels-Midlan Company	3.23	3.00	NA	(4.20)	(3.62)	3.00	3.28	6.28	
Assurant Inc.	1.69	9.50	6.30	6.30	6.29	7.10	1.75	8.85	
AutoZone Inc.	-	12.50	13.20	11.65	14.83	13.05	-	NA	
Booz Allen Hamilton Corporation	1.33	8.50	11.60	11.60	11.31	10.75	1.40	12.15	
Brady Corporation	1.42	13.00	7.70	7.70	9.36	9.44	1.49	10.93	
Brown-Forman Corporation 'B'	1.95	15.00	NA	(1.20)	(1.26)	15.00	2.10	17.10	
CACI International	-	7.00	10.40	6.70	10.35	8.61	-	NA	
Casella Waste Systems, Inc.	-	4.50	20.10	14.90	20.14	14.91	-	NA	
Casey's General Stores, Inc.	0.56	11.00	9.80	10.95	14.72	11.62	0.59	12.21	
Corteva, Inc.	1.25	9.00	13.30	13.50	12.15	11.99	1.32	13.31	
CSW Industrials	0.31	10.00	15.00	12.00	15.00	13.00	0.33	13.33	
Danaher Corporation	0.42	6.50	8.00	6.98	7.33	7.20	0.44	7.64	
Dolby Laboratories	1.50	9.50	NA	16.00	NA	12.75	1.60	14.35	
Fastenal Company	2.37	9.00	9.00	6.33	NA	8.11	2.47	10.58	
GATX Corporation	1.71	11.50	NA	12.00	NA	11.75	1.81	13.56	
Innospec Inc.	1.20	13.00	NA	7.50	7.50	9.33	1.26	10.59	
J. B. Hunt Transport Services	1.06	7.50	10.40	7.60	11.15	9.16	1.11	10.27	
Jack Henry & Associates, Inc.	1.33	6.50	7.50	7.50	8.23	7.43	1.38	8.81	
Juniper Networks, Inc.	2.45	7.50	3.60	11.00	13.19	8.82	2.56	11.38	
L3Harris Technologies, Inc.	2.06	9.50	9.30	9.24	9.17	9.30	2.16	11.46	
Lockheed Martin Corporation	2.67	9.50	4.40	4.80	3.01	5.43	2.74	8.17	
McKesson Corporation	0.43	8.00	13.60	11.76	12.40	11.44	0.45	11.89	
Microsoft Corporation	0.69	14.00	16.00	16.19	13.48	14.92	0.74	15.66	
MSA Safety Incorporated	1.10	8.50	NA	18.00	NA	13.25	1.17	14.42	
MSC Industrial Direct Co., Inc.	3.92	5.00	NA	9.12	NA	7.06	4.06	11.12	
Oracle Corporation	1.21	10.00	11.00	10.61	11.82	10.86	1.28	12.14	
O'Reilly Automotive, Inc.	-	10.50	12.80	11.10	12.80	11.80	-	NA	
OSI Systems, Inc.	-	10.50	11.00	8.00	12.25	10.44	-	NA	
Packaging Corporation of America	2.71	9.00	4.40	(14.29)	8.41	7.27	2.81	10.08	
Pfizer, Inc.	5.86	2.50	10.70	15.02	8.99	9.30	6.13	15.43	
Philip Morris International Inc.	5.03	5.00	7.80	9.36	9.39	7.89	5.23	13.12	
Prestige Consumer Healthcare Inc.	-	7.00	8.00	8.00	8.50	7.88	-	NA	
Selective Insurance Group, Inc.	1.49	16.50	16.00	16.55	16.56	16.40	1.61	18.01	(3)
Sensient Technologies Corporation	2.15	2.50	NA	3.80	15.00	7.10	2.23	9.33	
Service Corporation International	1.67	5.50	10.10	12.00	10.12	9.43	1.75	11.18	
Sherwin-Williams Company	0.92	11.00	11.10	11.32	10.32	10.94	0.97	11.91	
Smith (A.O.) Corporation	1.52	9.00	9.00	10.00	10.00	9.50	1.59	11.09	
Texas Instruments Incorporated	2.64	3.00	9.00	(2.80)	3.63	5.21	2.71	7.92	
Thermo Fisher Scientific Inc.	0.27	6.00	9.90	6.77	9.32	8.00	0.28	8.28	
UniFirst Corporation	0.79	9.50	NA	7.80	NA	8.65	0.82	9.47	
UnitedHealth Group Incorporated	1.64	12.00	13.00	12.38	10.84	12.06	1.74	13.80	
VeriSign Inc.	-	12.00	NA	8.00	NA	10.00	-	NA	
Verisk Analytics, Inc.	0.59	8.50	12.30	12.58	12.02	11.35	0.62	11.97	
Waters Corporation	-	6.50	5.30	5.54	5.76	5.77	-	NA	
Watsco, Inc.	2.25	9.00	NA	4.42	NA	6.71	2.33	9.04	
							Mean	11.32 %	
							Median	11.25 %	
						Average of Mean and Median		11.29 %	

NA= Not Available
NMF= Not Meaningful Figure

(1) Average of columns 2 through 5 excluding negative growth rates.
(2) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Group. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of July 31, 2024. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, www.yahoo.com and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.
(3) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:
Value Line Investment Survey
www.zacks.com Downloaded on 07/31/2024
www.yahoo.com Downloaded on 07/31/2024
S&P Capital IQ

Atmos Energy Corporation
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Fifty-Three Non-Price Regulated Companies	Proxy Group of Fifty-Three Non-Price Regulated Companies (excl. PRPM)
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	5.96 %	5.96 %
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.21)	(0.21)
3.	Adjusted Prospective Bond Yield	5.75 %	5.75 %
4.	Equity Risk Premium (3)	6.78	6.69
5.	Risk Premium Derived Common Equity Cost Rate	12.53 %	12.44 %

Notes: (1) Average forecast of Baa2 corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated August 1, 2024 and May 31, 2024 (see pages 7 and 8 of Schedule DWD-3). The estimates are detailed below.

Third Quarter 2024	5.90 %
Fourth Quarter 2024	5.90
First Quarter 2025	5.90
Second Quarter 2025	5.90
Third Quarter 2025	5.90
Fourth Quarter 2025	5.90
2026-2030	6.10
2031-2035	6.20
Average	5.96 %

(2) The average yield spread of Baa rated corporate bonds over A corporate bonds for the three months ending July 2024 . To reflect the A3 average rating of the non-utility proxy group, the prosepctive yield on Baa corporate bonds must be adjusted by 2/3 of the spread between A and Baa corporate bond yields as shown below:

	A Corp. Bond Yield	Baa Corp. Bond Yield	Spread
Jul-24	5.46 %	5.77 %	0.31 %
Jun-24	5.50	5.82	0.32
May-24	5.62	5.95	0.33
		Average yield spread	0.32 %
		2/3 of spread	0.21 %

(3) From page 5 of this Schedule.

Atmos Energy Corporation
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Fifty-Three Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Six Natural Gas Distribution Companies

	Moody's Long-Term Issuer Rating July 2024		Standard & Poor's Long-Term Issuer Rating July 2024	
Proxy Group of Fifty-Three Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Abbott Laboratories	Aa3	4.0	AA-	4.0
Agilent Technologies, Inc.	Baa1	8.0	BBB+	8.0
Air Products and Chemicals, Inc.	A2	6.0	A	6.0
Allstate Corporation (The)	A3	7.0	BBB+	8.0
Alphabet Inc.	Aa2	3.0	AA+	2.0
Altria Group, Inc.	A3	7.0	BBB	9.0
Analog Devices, Inc.	A2	6.0	A-	7.0
Apple Inc.	Aaa	1.0	AA+	2.0
Archer Daniels-Midlan Company	A2	6.0	A	6.0
Assurant Inc.	Baa2	9.0	BBB	9.0
AutoZone Inc.	Baa1	8.0	BBB	9.0
Booz Allen Hamilton Corporation	NA	--	NA	--
Brady Corporation	NA	--	NA	--
Brown-Forman Corporation 'B'	A1	5.0	A-	7.0
CACI International	NA	--	BB+	11.0
Casella Waste Systems, Inc.	NA	--	BB	12.0
Casey's General Stores, Inc.	NA	--	NA	--
Corteva, Inc.	NA	--	A-	7.0
CSW Industrials	NA	--	NA	--
Danaher Corporation	A3	7.0	A-	7.0
Dolby Laboratories	NA	--	NA	--
Fastenal Company	NA	--	NA	--
GATX Corporation	Baa2	9.0	BBB	9.0
Innospec Inc.	NA	--	NR	--
J. B. Hunt Transport Services	Baa1	8.0	BBB+	8.0
Jack Henry & Associates, Inc.	NA	--	NA	--
Juniper Networks, Inc.	Baa2	9.0	BBB	9.0
L3Harris Technologies, Inc.	Baa2	9.0	BBB	9.0
Lockheed Martin Corporation	A2	6.0	A-	7.0
McKesson Corporation	A3	7.0	BBB+	8.0
Microsoft Corporation	Aaa	1.0	AAA	1.0
MSA Safety Incorporated	NA	--	NA	--
MSC Industrial Direct Co., Inc.	NA	--	NA	--
Oracle Corporation	Baa2	9.0	BBB	9.0
O'Reilly Automotive, Inc.	Baa1	8.0	BBB	9.0
OSI Systems, Inc.	NA	--	NA	--
Packaging Corporation of America	Baa2	9.0	BBB	9.0
Pfizer, Inc.	A2	6.0	A	6.0
Philip Morris International Inc.	A2	6.0	A-	7.0
Prestige Consumer Healthcare Inc.	NA	--	BB	12.0
Selective Insurance Group, Inc.	Baa2	9.0	BBB	9.0
Sensient Technologies Corporation	WR	--	NR	--
Service Corporation International	Ba3	13.0	BB+	11.0
Sherwin-Williams Company	Baa2	9.0	BBB	9.0
Smith (A.O.) Corporation	NA	--	NA	--
Texas Instruments Incorporated	Aa3	4.0	A+	5.0
Thermo Fisher Scientific Inc.	A3	7.0	A-	7.0
UniFirst Corporation	NA	--	NA	--
UnitedHealth Group Incorporated	A2	6.0	A+	5.0
VeriSign Inc.	Baa3	10.0	BBB	9.0
Verisk Analytics, Inc.	Baa2	9.0	BBB	9.0
Waters Corporation	NA	--	NA	--
Watsco, Inc.	NA	--	NA	--
Average	A3	7.0	BBB+	7.6

Notes:
(1) From page 4 of Schedule DWD-3.

Source of Information:
Bloomberg Professional Services

Atmos Energy Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Proxy Group of Fifty-Three Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Six Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Fifty-Three Non-Price Regulated Companies	Proxy Group of Fifty-Three Non-Price Regulated Companies (excl. PRPM)
1.	Ibbotson Equity Risk Premium (1)	5.96 %	5.96 %
2.	Regression on Ibbotson Risk Premium Data (2)	6.98	6.98
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.11	NA
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	7.15	7.15
5	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Capital IQ S&P 500 Companies (5)	10.33	10.33
6.	Conclusion of Equity Risk Premium	7.70 %	7.60 %
7.	Adjusted Beta (6)	0.88	0.88
8.	Forecasted Equity Risk Premium	6.78 %	6.69 %

Notes:
(1) From note 1 of page 6 of Schedule DWD-3.
(2) From note 2 of page 6 of Schedule DWD-3.
(3) From note 3 of page 6 of Schedule DWD-3.
(4) From note 4 of page 6 of Schedule DWD-3.
(5) From note 5 of page 6 of Schedule DWD-3.
(6) Average of mean and median beta from page 6 of this Schedule.

Sources of Information:
Kroll 2023 SBBI® Yearbook
Value Line Summary and Index
Blue Chip Financial Forecasts, August 1, 2024 and May 31, 2024
Bloomberg Professional Services

Atmos Energy Corporation
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	
Proxy Group of Fifty-Three Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)	
Abbott Laboratories	0.90	0.79	0.85	8.63 %	4.36 %	11.69 %	12.02 %	11.86 %	
Agilent Technologies, Inc.	0.95	1.11	1.03	8.63	4.36	13.25	13.18	13.21	
Air Products and Chemicals, Inc.	0.90	0.80	0.85	8.63	4.36	11.69	12.02	11.86	
Allstate Corporation (The)	1.00	0.52	0.76	8.63	4.36	10.92	11.43	11.18	
Alphabet Inc.	0.90	1.17	1.04	8.63	4.36	13.33	13.25	13.29	
Altria Group, Inc.	0.85	0.56	0.70	8.63	4.36	10.40	11.05	10.72	
Analog Devices, Inc.	1.00	1.16	1.08	8.63	4.36	13.68	13.51	13.59	
Apple Inc.	0.95	1.14	1.04	8.63	4.36	13.33	13.25	13.29	
Archer Daniels-Midlan Company	0.95	0.68	0.81	8.63	4.36	11.35	11.76	11.55	
Assurant Inc.	0.90	0.78	0.84	8.63	4.36	11.61	11.95	11.78	
AutoZone Inc.	0.95	0.69	0.82	8.63	4.36	11.43	11.82	11.63	
Booz Allen Hamilton Corporation	0.85	0.83	0.84	8.63	4.36	11.61	11.95	11.78	
Brady Corporation	0.95	0.70	0.83	8.63	4.36	11.52	11.89	11.70	
Brown-Forman Corporation 'B'	0.90	0.87	0.88	8.63	4.36	11.95	12.21	12.08	
CACI International	0.90	0.79	0.84	8.63	4.36	11.61	11.95	11.78	
Casella Waste Systems, Inc.	0.85	0.71	0.78	8.63	4.36	11.09	11.56	11.33	
Casey's General Stores, Inc.	0.85	0.66	0.75	8.63	4.36	10.83	11.37	11.10	
Corteva, Inc.	0.95	0.79	0.87	8.63	4.36	11.87	12.15	12.01	
CSW Industrials	0.85	0.84	0.85	8.63	4.36	11.69	12.02	11.86	
Danaher Corporation	0.90	0.99	0.95	8.63	4.36	12.56	12.66	12.61	
Dolby Laboratories	0.95	0.88	0.91	8.63	4.36	12.21	12.41	12.31	
Fastenal Company	0.90	0.92	0.91	8.63	4.36	12.21	12.41	12.31	
GATX Corporation	0.95	0.93	0.94	8.63	4.36	12.47	12.60	12.53	
Innospec Inc.	1.00	0.89	0.94	8.63	4.36	12.47	12.60	12.53	
J. B. Hunt Transport Services	0.95	1.00	0.97	8.63	4.36	12.73	12.79	12.76	
Jack Henry & Associates, Inc.	0.85	0.85	0.85	8.63	4.36	11.69	12.02	11.86	
Juniper Networks, Inc.	0.95	0.79	0.87	8.63	4.36	11.87	12.15	12.01	
L3Harris Technologies, Inc.	0.90	0.90	0.90	8.63	4.36	12.12	12.34	12.23	
Lockheed Martin Corporation	0.85	0.55	0.70	8.63	4.36	10.40	11.05	10.72	
McKesson Corporation	0.80	0.47	0.63	8.63	4.36	9.80	10.59	10.19	(4)
Microsoft Corporation	0.85	1.09	0.97	8.63	4.36	12.73	12.79	12.76	
MSA Safety Incorporated	0.95	0.94	0.94	8.63	4.36	12.47	12.60	12.53	
MSC Industrial Direct Co., Inc.	0.90	0.82	0.86	8.63	4.36	11.78	12.08	11.93	
Oracle Corporation	0.80	1.14	0.97	8.63	4.36	12.73	12.79	12.76	
O'Reilly Automotive, Inc.	0.90	0.63	0.76	8.63	4.36	10.92	11.43	11.18	
OSI Systems, Inc.	0.90	1.00	0.95	8.63	4.36	12.56	12.66	12.61	
Packaging Corporation of America	0.95	0.86	0.91	8.63	4.36	12.21	12.41	12.31	
Pfizer, Inc.	0.80	0.60	0.70	8.63	4.36	10.40	11.05	10.72	
Philip Morris International Inc.	0.95	0.73	0.84	8.63	4.36	11.61	11.95	11.78	
Prestige Consumer Healthcare Inc.	0.85	0.65	0.75	8.63	4.36	10.83	11.37	11.10	
Selective Insurance Group, Inc.	0.85	0.60	0.72	8.63	4.36	10.57	11.18	10.87	
Sensient Technologies Corporation	0.95	0.93	0.94	8.63	4.36	12.47	12.60	12.53	
Service Corporation International	0.95	0.77	0.86	8.63	4.36	11.78	12.08	11.93	
Sherwin-Williams Company	0.95	1.15	1.05	8.63	4.36	13.42	13.31	13.36	
Smith (A.O.) Corporation	0.90	1.03	0.97	8.63	4.36	12.73	12.79	12.76	
Texas Instruments Incorporated	0.85	1.10	0.98	8.63	4.36	12.81	12.86	12.84	
Thermo Fisher Scientific Inc.	0.85	0.97	0.91	8.63	4.36	12.21	12.41	12.31	
UniFirst Corporation	0.90	0.79	0.84	8.63	4.36	11.61	11.95	11.78	
UnitedHealth Group Incorporated	0.95	0.34	0.64	8.63	4.36	9.88	10.66	10.27	(4)
VeriSign Inc.	0.90	0.97	0.93	8.63	4.36	12.38	12.53	12.46	
Verisk Analytics, Inc.	0.90	0.94	0.92	8.63	4.36	12.30	12.47	12.38	
Waters Corporation	0.95	1.13	1.04	8.63	4.36	13.33	13.25	13.29	
Watsco, Inc.	0.90	1.25	1.08	8.63	4.36	13.68	13.51	13.59	
		Mean	0.88			11.94 %	12.20 %	12.14 %	
		Median	0.87			11.87 %	12.15 %	12.08 %	
		Average of Mean and Median	0.88			11.91 %	12.18 %	12.11 %	

Notes:
(1) From note 1 of page 2 of Schedule DWD-4.
(2) From note 2 of page 2 of Schedule DWD-4.
(3) Average of CAPM and ECAPM cost rates.
(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Atmos Energy Corporation
Traditional CAPM and ECAPM Results (excluding the PRPM MRP) for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	
Proxy Group of Fifty-Three Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)	
Abbott Laboratories	0.90	0.79	0.85	8.52 %	4.36 %	11.60 %	11.92 %	11.76 %	
Agilent Technologies, Inc.	0.95	1.11	1.03	8.52	4.36	13.14	13.08	13.11	
Air Products and Chemicals, Inc.	0.90	0.80	0.85	8.52	4.36	11.60	11.92	11.76	
Allstate Corporation (The)	1.00	0.52	0.76	8.52	4.36	10.84	11.35	11.09	
Alphabet Inc.	0.90	1.17	1.04	8.52	4.36	13.22	13.14	13.18	
Altria Group, Inc.	0.85	0.56	0.70	8.52	4.36	10.33	10.97	10.65	
Analog Devices, Inc.	1.00	1.16	1.08	8.52	4.36	13.57	13.39	13.48	
Apple Inc.	0.95	1.14	1.04	8.52	4.36	13.22	13.14	13.18	
Archer Daniels-Midlan Company	0.95	0.68	0.81	8.52	4.36	11.26	11.67	11.47	
Assurant Inc.	0.90	0.78	0.84	8.52	4.36	11.52	11.86	11.69	
AutoZone Inc.	0.95	0.69	0.82	8.52	4.36	11.35	11.73	11.54	
Booz Allen Hamilton Corporation	0.85	0.83	0.84	8.52	4.36	11.52	11.86	11.69	
Brady Corporation	0.95	0.70	0.83	8.52	4.36	11.43	11.80	11.62	
Brown-Forman Corporation 'B'	0.90	0.87	0.88	8.52	4.36	11.86	12.12	11.99	
CACI International	0.90	0.79	0.84	8.52	4.36	11.52	11.86	11.69	
Casella Waste Systems, Inc.	0.85	0.71	0.78	8.52	4.36	11.01	11.48	11.24	
Casey's General Stores, Inc.	0.85	0.66	0.75	8.52	4.36	10.75	11.29	11.02	
Corteva, Inc.	0.95	0.79	0.87	8.52	4.36	11.78	12.05	11.91	
CSW Industrials	0.85	0.84	0.85	8.52	4.36	11.60	11.92	11.76	
Danaher Corporation	0.90	0.99	0.95	8.52	4.36	12.46	12.56	12.51	
Dolby Laboratories	0.95	0.88	0.91	8.52	4.36	12.12	12.31	12.21	
Fastenal Company	0.90	0.92	0.91	8.52	4.36	12.12	12.31	12.21	
GATX Corporation	0.95	0.93	0.94	8.52	4.36	12.37	12.50	12.44	
Innospec Inc.	1.00	0.89	0.94	8.52	4.36	12.37	12.50	12.44	
J. B. Hunt Transport Services	0.95	1.00	0.97	8.52	4.36	12.63	12.69	12.66	
Jack Henry & Associates, Inc.	0.85	0.85	0.85	8.52	4.36	11.60	11.92	11.76	
Juniper Networks, Inc.	0.95	0.79	0.87	8.52	4.36	11.78	12.05	11.91	
L3Harris Technologies, Inc.	0.90	0.90	0.90	8.52	4.36	12.03	12.24	12.14	
Lockheed Martin Corporation	0.85	0.55	0.70	8.52	4.36	10.33	10.97	10.65	
McKesson Corporation	0.80	0.47	0.63	8.52	4.36	9.73	10.52	10.12	(4)
Microsoft Corporation	0.85	1.09	0.97	8.52	4.36	12.63	12.69	12.66	
MSA Safety Incorporated	0.95	0.94	0.94	8.52	4.36	12.37	12.50	12.44	
MSC Industrial Direct Co., Inc.	0.90	0.82	0.86	8.52	4.36	11.69	11.99	11.84	
Oracle Corporation	0.80	1.14	0.97	8.52	4.36	12.63	12.69	12.66	
O'Reilly Automotive, Inc.	0.90	0.63	0.76	8.52	4.36	10.84	11.35	11.09	
OSI Systems, Inc.	0.90	1.00	0.95	8.52	4.36	12.46	12.56	12.51	
Packaging Corporation of America	0.95	0.86	0.91	8.52	4.36	12.12	12.31	12.21	
Pfizer, Inc.	0.80	0.60	0.70	8.52	4.36	10.33	10.97	10.65	
Philip Morris International Inc.	0.95	0.73	0.84	8.52	4.36	11.52	11.86	11.69	
Prestige Consumer Healthcare Inc.	0.85	0.65	0.75	8.52	4.36	10.75	11.29	11.02	
Selective Insurance Group, Inc.	0.85	0.60	0.72	8.52	4.36	10.50	11.09	10.80	
Sensient Technologies Corporation	0.95	0.93	0.94	8.52	4.36	12.37	12.50	12.44	
Service Corporation International	0.95	0.77	0.86	8.52	4.36	11.69	11.99	11.84	
Sherwin-Williams Company	0.95	1.15	1.05	8.52	4.36	13.31	13.20	13.26	
Smith (A.O.) Corporation	0.90	1.03	0.97	8.52	4.36	12.63	12.69	12.66	
Texas Instruments Incorporated	0.85	1.10	0.98	8.52	4.36	12.71	12.76	12.73	
Thermo Fisher Scientific Inc.	0.85	0.97	0.91	8.52	4.36	12.12	12.31	12.21	
UniFirst Corporation	0.90	0.79	0.84	8.52	4.36	11.52	11.86	11.69	
UnitedHealth Group Incorporated	0.95	0.34	0.64	8.52	4.36	9.81	10.58	10.20	(4)
VeriSign Inc.	0.90	0.97	0.93	8.52	4.36	12.29	12.44	12.36	
Verisk Analytics, Inc.	0.90	0.94	0.92	8.52	4.36	12.20	12.37	12.29	
Waters Corporation	0.95	1.13	1.04	8.52	4.36	13.22	13.14	13.18	
Watsco, Inc.	0.90	1.25	1.08	8.52	4.36	13.57	13.39	13.48	
		Mean	0.88			11.85 %	12.11 %	12.05 %	
		Median	0.87			11.78 %	12.05 %	11.99 %	
		Average of Mean and Median	0.88			11.82 %	12.08 %	12.02 %	

Notes:
(1) From note 1 of page 2 of Schedule DWD-4.
(2) From note 2 of page 2 of Schedule DWD-4.
(3) Average of CAPM and ECAPM cost rates.
(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Atmos Energy Corporation
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on July 31, 2024 (1) (millions)		[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	Atmos Energy Corporation	$ 606.404		8	1.14%	
2.	Proxy Group of Six Natural Gas Distribution Companies	$ 4,249.683	7.0 x	5	0.95%	0.19%
			[A]	[B]	[C]	[D]

	Decile	Market Capitalization of Smallest Company (millions)	Market Capitalization of Largest Company (millions)	Size Premium (Return in Excess of CAPM)*
Largest	1	$ 36,942.976	$ 2,662,326.048	-0.06%
	2	14,910.719	36,391.113	0.46%
	3	7,493.607	14,820.048	0.61%
	4	4,622.261	7,461.284	0.64%
	5	3,011.224	4,621.785	0.95%
	6	1,864.293	3,010.806	1.21%
	7	1,050.083	1,862.491	1.39%
	8	555.880	1,046.037	1.14%
	9	213.039	554.523	1.99%
Smallest	10	1.576	212.644	4.70%

*From 2024 Kroll Cost of Capital Navigator

Notes:
(1) From page 2 of this Schedule.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.19% in Column [4], Line No. 2 is derived as follows 0.19% = 1.14% - 0.95%.

Atmos Energy Corporation
Market Capitalization of Atmos Energy Corporation and the
Proxy Group of Six Natural Gas Distribution Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2023 (millions)	[2] Book Value per Share at Fiscal Year End 2021 (1)	[3] Total Common Equity at Fiscal Year End 2023 (millions)	[4] Closing Stock Market Price on July 31, 2024	[5] Market-to-Book Ratio on July 31, 2024 (2)	[6] Market Capitalization on July 31, 2024 (3) (millions)
Atmos Energy Corporation		NA	NA	$ 382.469 (4)	NA		
Based upon Proxy Group of Six Natural Gas Distribution Companies						158.6 (5)	$ 606.404 (6)
Proxy Group of Six Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	148.493	$ 73.203	$ 10,870.064	$ 127.880	174.7 %	$ 18,989.257
New Jersey Resources Corporation	NYSE	97.584	20.400	1,990.735	46.750	229.2	4,562.073
NiSource Inc.	NYSE	447.382	17.398	7,783.500	31.250	179.6	13,980.677
Northwest Natural Holding Company	NYSE	37.631	34.116	1,283.838	39.980	117.2	1,504.487
ONE Gas, Inc.	NYSE	56.546	48.914	2,765.877	69.630	142.4	3,937.293
Spire Inc.	NYSE	53.170	54.867	2,917.300	66.590	121.4	3,540.605
Median		77.065	$ 41.515	$ 2,841.589	$ 56.670	158.6 %	$ 4,249.683

NA= Not Available

Notes:
(1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Atmos Energy Corporation on July 31, 2024 is assumed to be equal to the market-to-book ratio of theProxy Group of Six Natural Gas Distribution Companies on July 31, 2024 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information:
2023 Annual Forms 10K
yahoo.finance.com
Bloomberg Professional

Atmos Energy Corporation
Hypothetical Example: Flotation Cost Recovery

Return on Equity	10.75%
Flotation Costs	2.75%
Market Value	$ 25.00
Dividend Yield	3.50%
Growth Rate	7.25%
Adjusted ROE	10.85%
Flotation Cost Recovery:	**No**
DCF Estimate	**10.65%**

	Common Stock	Retained Earnings	Book Value	Market Price	Market/ Book Value	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 24.31		$ 24.31	$ 25.00	1.0283	$ 2.61	$ 0.88	33.48%
2	$ 24.31	$ 1.74	$ 26.05	$ 26.79	1.0283	$ 2.80	$ 0.94	33.48%
3	$ 24.31	$ 3.60	$ 27.91	$ 28.70	1.0283	$ 3.00	$ 1.00	33.48%
4	$ 24.31	$ 5.60	$ 29.91	$ 30.76	1.0283	$ 3.22	$ 1.08	33.48%
5	$ 24.31	$ 7.74	$ 32.05	$ 32.96	1.0283	$ 3.45	$ 1.15	33.48%
6	$ 24.31	$ 10.03	$ 34.34	$ 35.31	1.0283	$ 3.69	$ 1.24	33.48%
7	$ 24.31	$ 12.48	$ 36.80	$ 37.84	1.0283	$ 3.96	$ 1.32	33.48%
8	$ 24.31	$ 15.12	$ 39.43	$ 40.54	1.0283	$ 4.24	$ 1.42	33.48%
9	$ 24.31	$ 17.94	$ 42.25	$ 43.44	1.0283	$ 4.54	$ 1.52	33.48%
10	$ 24.31	$ 20.96	$ 45.27	$ 46.55	1.0283	$ 4.87	$ 1.63	33.48%
	Growth Rate		7.15%	7.15%		7.15%	7.15%	

Return on Equity	10.75%
Flotation Costs	2.75%
Market Value	$ 25.00
Dividend Yield	3.50%
Growth Rate	7.25%
Adjusted ROE	10.85%
Flotation Cost Recovery:	**Yes**
DCF Estimate	**10.75%**

	Common Stock	Retained Earnings	Book Value	Market Price	Market/ Book Value	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 24.31		$ 24.31	$ 25.00	1.0283	$ 2.64	$ 0.88	33.17%
2	$ 24.31	$ 1.76	$ 26.08	$ 26.81	1.0283	$ 2.83	$ 0.94	33.17%
3	$ 24.31	$ 3.65	$ 27.97	$ 28.76	1.0283	$ 3.03	$ 1.01	33.17%
4	$ 24.31	$ 5.68	$ 29.99	$ 30.84	1.0283	$ 3.25	$ 1.08	33.17%
5	$ 24.31	$ 7.86	$ 32.17	$ 33.08	1.0283	$ 3.49	$ 1.16	33.17%
6	$ 24.31	$ 10.19	$ 34.50	$ 35.48	1.0283	$ 3.74	$ 1.24	33.17%
7	$ 24.31	$ 12.69	$ 37.00	$ 38.05	1.0283	$ 4.01	$ 1.33	33.17%
8	$ 24.31	$ 15.37	$ 39.68	$ 40.81	1.0283	$ 4.31	$ 1.43	33.17%
9	$ 24.31	$ 18.25	$ 42.56	$ 43.76	1.0283	$ 4.62	$ 1.53	33.17%
10	$ 24.31	$ 21.33	$ 45.65	$ 46.94	1.0283	$ 4.95	$ 1.64	33.17%
	Growth Rate		7.25%	7.25%		7.25%	7.25%	

Atmos Energy Corporation
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances and Flotation Costs for FY 2016 - 2024

Fiscal Year	Transaction (1)	[Column 1] Shares Issued	[Column 2] Average Offering Price per Share	[Column 3] Net Proceeds per Share (2)	[Column 4] Gross Equity Issue before Costs	[Column 5] Total Net Proceeds	[Column 6] Total Flotation Costs (3)	[Column 7] Flotation Cost Percentage (4)
2024	At the Market Equity Offering	6,401,469	$ 117.2233	$ 116.6373	$ 750,401,394	$ 746,649,868	$ 3,751,526	0.50%
2023	At the Market Equity Offering	7,272,261	$ 112.7133	$ 111.0946	$ 819,680,535	$ 807,908,920	$ 11,771,616	1.44%
2022	At the Market Equity Offering	7,907,883	$ 100.0634	$ 98.3843	$ 791,290,027	$ 778,011,289	$ 13,278,738	1.68%
2021	At the Market Equity Offering	6,130,875	$ 101.5775	$ 99.0072	$ 622,758,775	$ 607,000,833	$ 15,757,941	2.53%
2020	At the Market Equity Offering	6,101,916	NA	NA	$ 632,630,269	$ 625,894,599	$ 6,735,669	1.06%
2019	At the Market Equity Offering	5,390,836	$ 92.7500	$ 91.6555	$ 500,000,000	$ 494,100,000	$ 5,900,000	1.18%
2018	At the Market Equity Offering	4,558,404	$ 87.7500	$ 86.6751	$ 400,000,000	$ 395,100,000	$ 4,900,000	1.23%
2017	At the Market Equity Offering	1,303,494	$ 76.7169	$ 75.7963	$ 100,000,000	$ 98,800,000	$ 1,200,000	1.20%
2016	At the Market Equity Offering	1,360,756	$ 73.4886	$ 72.4597	$ 100,000,000	$ 98,600,000	$ 1,400,000	1.40%
					$ 4,716,760,999	$ 4,652,065,510	$ 64,695,490	1.37%

Flotation Cost Adjustment

	Average Dividend Yield	Average Projected EPS Growth Rate	Adjusted Dividend Yield	Average DCF Cost Rate Unadjusted for Flotation (5)	DCF Cost Rate Adjusted for Flotation (6)	Flotation Cost Adjustment (7)
Proxy Group of Six Natural Gas Distribution Companies	4.08 %	5.76 %	4.20 %	9.96 %	10.02 %	0.06 %

Source of Information: Atmos Energy Corporation SEC Form 10-Ks, Company-Provided Data

Notes provided on page 2 of this Schedule

Atmos Energy Corporation
Notes to Accompany the
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

(1) Atmos Energy Corporation SEC Filings, Company-provided.

(2) Column 5 ÷ Column 1.

(3) Column 4 - Column 5.

(4) Column 6 ÷ Column 4.

(5) Using the average growth rate from Schedule DWD-2.

(6) Adjustment for flotation costs based on adjusting the average DCF constant growth cost rate in accordance with the following:

$$K = \frac{D(1+0.5g)}{P(1-F)} + g\,,$$

where g is the growth factor and F is the percentage of flotation costs.

(7) Flotation cost adjustment of 0.06% equals the difference between the flotation adjusted average DCF cost rate of 10.02% and the unadjusted average DCF cost rate of 9.96% of the Utility Proxy Group.

Sources of Information:

Company SEC Filings; Company-Provided

Atmos Energy Corporation
Summary of Investment Riders for Alternative Regulation/Incentive Plans
Proxy Group of Six Natural Gas Distribution Companies

Company	Parent	State	Capital Investment (1)
Atmos Energy	ATO	Colorado	✓
Atmos Energy	ATO	Kansas	✓
Atmos Energy	ATO	Kentucky	✓
Atmos Energy	ATO	Louisiana	✓
Atmos Energy	ATO	Mississippi	✓
Atmos Energy	ATO	Tennessee	✓
Atmos Energy	ATO	Texas	✓
Atmos Energy	ATO	Virginia	✓
New Jersey Natural Gas	NJR	New Jersey	✓
Northern Indiana Public Service Company, LLC	NI	Indiana	✓
Columbia Gas of Kentucky, Inc.	NI	Ohio	✓
Columbia Gas of Ohio, Inc.	NI	Ohio	✓
Columbia Gas of Pennsylvania, Inc.	NI	Pennsylvania	✓
Columbia Gas of Maryland, Inc.	NI	Pennsylvania	✓
Columbia Gas of Virginia, Inc.	NI	Virginia	✓
Northwest Natural Gas	NWN	Oregon	
Northwest Natural Gas	NWN	Washington	
Kansas Gas Service	OGS	Kansas	✓
Oklahoma Natural Gas	OGS	Oklahoma	
Texas Gas Service	OGS	Texas	✓
Spire Alabama Inc.	SR	Alabama	
Spire Mississippi Inc.	SR	Mississippi	
Spire Missouri Inc.	SR	Missouri	✓

Notes:
(1) Includes recovery of costs related to infrastructure replacement, system integrity/hardening, and other capital expenditures.
Source: Company SEC Form 10-Ks; Operating company tariffs; Regulatory Research Associates.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

DIRECT TESTIMONY OF PAUL H. RAAB

INDEX TO THE DIRECT TESTIMONY
OF PAUL H. RAAB, WITNESS FOR
ATMOS ENERGY CORPORATION

I. INTRODUCTION 1

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Paul H. Raab, and my business address is 5313 Portsmouth Road, Bethesda, MD 20816. I am an independent economic consultant.

Q. ON WHOSE BEHALF ARE YOU APPEARING TODAY?

A. I am appearing on behalf of Atmos Energy Corporation, Kentucky/Mid-States Division ("Atmos Energy" or "Company").

II. QUALIFICATIONS

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a B.A. in Economics from Rutgers University and an M.A. from the State University of New York at Binghamton with a concentration in Econometrics. While attending Rutgers, I studied as a Henry Rutgers Scholar.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I have been providing consulting services to the utility industry for over forty years, having assisted electric, gas, telephone, and water utilities; Commissions; and intervenor clients in a variety of areas. I am trained as a quantitative economist so that most of this assistance has been in the form of mathematical and economic analysis and information systems development. My areas of focus are planning issues, costing and rate design analysis, and depreciation and life analysis. I began my career with the professional services firm that is now known as Ernst & Young, where I was employed for ten years.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE COMMISSIONS IN REGULATORY PROCEEDINGS?

A. Yes. I have previously provided expert testimony before this Commission in several dockets, as well as a number of other state regulatory authorities as enumerated in Exhibit PHR-1. In addition, I have presented expert testimony before the Federal Energy Regulatory Commission, the Pennsylvania House Consumer Affairs Committee, the Michigan House Economic Development and Energy Committee, the Province of Saskatchewan, and the United States Tax Court. Details on the subject matter of the testimony presented are provided in Exhibit PHR-1.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Company's class cost of service studies (COSS). These studies are used to guide the Company in assigning the required revenue increase to the various customer classes and in designing rates.

Q. WHY HAVE YOU PREPARED MULTIPLE CLASS COST OF SERVICE STUDIES IN THIS CASE?

A. In its order in Case No. 2013-00148 the Commission stated that, "the Commission strongly encourages Atmos-Ky. to file multiple-methodology COSSes in future rate cases in order to give the Commission a range of reasonable results for use in determining revenue allocation and rate design." Order at 34. This directive has guided the Company's COSS presentation in its base rate filings from that point forward and I continue it in this case.

Consistent with the Company's practice since Case No. 2013-00148, I have

developed three COSS for this case that differ based on the treatment of distribution mains, which is generally recognized as having a significant impact on the class results. As the Commission noted in its order in Case No. 2013-00148: "Although certain minor differences exist between the two COSSes, Atmos-Ky. and the AG agree that the primary difference lies in the treatment of distribution mains." Order at 32.

Q. PLEASE DESCRIBE THESE STUDIES.

A. The first study, termed the "customer/demand" study, classifies investments in distribution mains as both customer- and demand-related using the "minimum system" approach. Such a classification reflects the fact that the Company's level of investment in distribution mains is driven by the maximum demand that customers place on the system, but that there is also a minimum level of investments in distribution mains that would be necessary regardless of the level of such demands. As indicated in the National Association of Regulatory Utility Commissioners (NARUC) publication entitled Gas Rate Design, "[t]he argument for inclusion of [customer] cost[s] relating to a service line and/or a 'minimum size or zero inch' distribution main is that these facilities are necessary to connect the customer to the system and thus afford him the opportunity to take service if he so desires." Gas Rate Design at 29, 30. I find this rationale compelling, and generally favor a customer/demand classification of distribution mains in my work in other jurisdictions.

However, Gas Rate Design also notes that "[t]he contra argument is that mains and services are installed to serve demands of the customers and should be

allocated [exclusively] to that function." Accordingly, I have prepared a second COSS, termed the "demand-only" study, which classifies investments in distribution mains as only demand-related, consistent with this discussion from Gas Rate Design.

Finally, I have prepared a third study, entitled the "energy/demand" study, which reflects the Commission's 1987 guidance that, "cost-of-service methodologies should give some consideration to volume of use." Administrative Case No. 297, *An Investigation of the Impact of Federal Policy on Natural Gas to Kentucky Consumers and Suppliers* ("Admin. 297") (Ky. PSC May 29, 1987), Order at 47. While I do not believe that such an approach reflects distribution mains investment cost incurrence, and therefore is a results-driven choice of classification methodologies, I have nevertheless provided such a study for the Commission's consideration.

IV. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor five exhibits. Exhibit PHR-1 is a summary of my qualifications and experience. Exhibits PHR-2, PHR-3 and PHR-4 are the results of the Company's class cost of service studies based on a customer/demand allocation of distribution mains, a demand-only allocation of distribution mains and an energy/demand allocation of distribution mains, respectively. Finally, Exhibit PHR-5 is a summary exhibit that highlights the two most important differences among the three studies: (1) the suggested allocation of the proposed revenue increase and (2) the level of

fixed costs indicated by each study.

The above-designated exhibits were prepared by me or under my direction and supervision and satisfy Filing Requirement ("FR") 16(7)(v), which I also sponsor.[a]

V. ORGANIZATION OF TESTIMONY

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into one additional section, Section VI, which describes the class cost of service studies.

VI. CLASS COST OF SERVICE

a. Background

Q. WHAT IS A CLASS COST OF SERVICE ANALYSIS?

A. A class cost of service analysis is the process by which the costs that a utility incurs to serve individual classes of customers are linked to the classes of customers that caused those costs to be incurred.

Q. WHY IS IT NECESSARY TO ALLOCATE COSTS TO THE DIFFERENT CUSTOMER CLASSES?

A. It is a generally accepted utility ratemaking principle that rates should be based on costs. This statement applies not only to the overall level of costs incurred by the utility, but also to the costs that the utility incurs to serve individual services, classes

[a] "Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application: (v) If the utility provides gas, electric, sewage, or water utility service and has annual gross revenues greater than $5,000,000 in the division for which a rate adjustment is sought, a cost of service study based on a methodology generally accepted within the industry and based on current and reliable data from a single time period. . . ."

of customers, and segments of the utility's business. Adherence to this principle is complicated by the fact that many of the costs incurred to provide different types of service are "joint" costs and many are "common" costs, neither of which has a theoretically precise method by which they can be assigned to the different products produced because of the incurrence of these costs.

Joint costs occur when the provision of one service is an automatic by-product of another (e.g., the delivery of natural gas at different times of the year). Common costs are incurred when several outputs are produced using the same facilities or inputs (e.g., administrative and general expenses).

Thus, cost of service studies are the primary method used to allocate the common and joint costs incurred by the utility in serving different customer classes. They are used for five purposes:

1. To attribute costs to different categories of customers based on how those customers cause costs to be incurred;
2. To determine how costs will be recovered from customers within each customer class;
3. To calculate the costs of individual types of service based on the costs each service requires the utility to expend;
4. To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets; and
5. To separate costs between different regulatory jurisdictions.

Q. HOW ARE THE COSTS INCURRED BY THE UTILITY ALLOCATED TO THE DIFFERENT CUSTOMER CLASSES?

A. These costs are allocated to the different customer classes in three steps: functionalization, classification, and allocation.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS.

A. Functionalization is the process whereby the capital and operating costs incurred by the utility to provide service are categorized by function. The typical functions of a natural gas utility are transmission, distribution, customer service and facilities, and administrative and general. The transmission function includes those assets and expenses associated with the delivery of natural gas from the field to the distribution system. The assets and expenses involved in the delivery of natural gas to ultimate customers, except those that can be directly assigned to a particular customer, are included in the distribution function. Those distribution costs that can be directly assigned to a particular customer (e.g., service drops and meters) plus the meter reading and other customer service functions such as billing and collections are included in the customer service and facilities function. The administrative and general function includes management costs that cannot be directly assigned to the other major cost functions.

Q. WHY DOES ONE FUNCTIONALIZE COSTS?

A. Costs are functionalized so that they can be more easily classified, which is the next step in the cost-of-service analysis.

Q. HOW WAS THE FUNCTIONALIZATION PROCESS PERFORMED FOR ATMOS ENERGY?

A. The Company's accounting processes follow the FERC Uniform System of Accounts. In large measure, this system of accounts records costs by the function for which they were incurred. Thus, the costs that I work with in the cost-of-service analysis are already grouped by function.

Q. PLEASE DESCRIBE THE CLASSIFICATION PROCESS.

A. The classification process recognizes that the utility's costs are incurred for several purposes: to meet customers' peak demands (demand-related costs), to provide energy (energy- or commodity-related costs), and because there are customers on the system (customer-related costs). The classification process groups the utility's costs by the purpose for which they were incurred. The cost of odorant is the best example of a cost that is incurred in direct proportion to the amount of natural gas that flows through the system and is therefore classified as an energy-related cost. On the other hand, metering costs are primarily driven by the number of customers on the system and would be classified as customer-related costs.

Q. HOW WERE THE COMPANY'S COSTS CLASSIFIED IN THIS STUDY?

A. All the studies discussed above rely on the same classification scheme for all costs and investments other than investments in distribution mains. The classification of distribution mains investment costs differs among the three studies as follows. For the customer/demand study, distribution mains investment costs are classified as both customer-related and demand-related based on the results of a minimum system study, consistent with Company studies in prior cases. The demand-only

study classifies distribution mains investment costs as only demand-related. The energy/demand study classifies distribution mains investment costs as both demand-related and commodity-related, based on the average and excess demand approach, consistent with the methodology proposed by the Attorney General in Docket No. 2013-00148. The first two approaches are consistent with the suggested classification of the NARUC. The third approach is consistent with prior Commission guidance related to cost-of-service methodologies. My testimony below explains the specific classification factors employed.

Q. PLEASE DESCRIBE THE ALLOCATION PROCESS.

A. The allocation process is one in which the functionalized and classified costs from above are assigned to specific customer classes. It is assumed that the load characteristics of the customers within each of the major customer classes are relatively homogeneous with respect to their usage characteristics. Thus, costs can be allocated to customer classes based on these characteristics. Those costs that have been classified as demand-related costs in the classification process above are allocated among the customer classes based on demands imposed on the system during the peak day. Commodity- or energy-related costs are allocated based on the energy that the system must supply to meet the needs of these customers. Customer-related costs are allocated to the different customer classes based on the number of customers.

Q. HOW ARE THESE COSTS ALLOCATED TO THE COMPANY'S DIFFERENT CUSTOMER CLASSES?

A. First, customers are divided into groups or classes. These classes are populated with

customers having similar natural gas demand characteristics. The customers within each class can therefore be billed pursuant to a single rate schedule containing a customer charge and an energy charge since their load profiles are sufficiently similar. Next, costs are examined to determine why the utility incurred them and how customers' usage characteristics impact the utility's cost incurrence decisions. Finally, a demand characteristic is associated with each cost incurred; each customer class's contribution to that cost provides the basis for the allocation of the associated cost.

Q. WHAT ARE THESE "USAGE CHARACTERISTICS" THAT CUSTOMERS PLACE ON THE SYSTEM?

A. The customer's request for service is a cost causative demand characteristic that necessarily results in an immediate investment in a regulator, a service line and metering facilities and establishes a commitment on the part of the company to provide, among other things, answers to questions and a monthly billing. Hence, the very existence of this customer-utility relationship causes the incurrence of cost. The amount of natural gas taken from the utility system, usually expressed volumetrically (Mcf) or in terms of the energy content of the natural gas itself (therms or Dth) and referred to as the customer's energy use or usage, is an important cost causative characteristic as well. Additionally, as my testimony will describe in more detail, the magnitude of costs incurred to serve a customer is also driven by the customer's potential rate of energy use, usually expressed in design day usage, and referred to as the customer's demand.

Q. HOW DO SUCH DEMANDS AFFECT COST INCURRENCE?

A. Cost incurrence is strongly driven by two primary factors, the physical connection to the system and the rate at which energy is used. As described above, the physical connection to the system involves investments (a regulator, a service line and metering facilities) and establishes a commitment on the part of the company to provide monthly billing, even if no customer usage occurs. Likewise, the rate at which energy is used serves as the link to the incurrence and magnitude of demand related utility costs.

Q. WHY HAVE YOU EMPHASIZED THE PHYSICAL CONNECTION TO THE SYSTEM AND THE RATE AT WHICH ENERGY IS USED WHEN DESCRIBING COST CAUSATIVE CUSTOMER UTILIZATION FACTORS?

A. There are two particularly important factors that drive a natural gas utility's cost incurrence. First, it is a capital-intensive enterprise. Second, the system must be sized so that it has the capability to deliver natural gas to customers during extremely cold conditions (the “design day”), even though this intensity of usage only occurs a few days out of the year, if at all. This combination of capital intensity and sizing to meet peak day demands dictates the prominence of the physical connection and the "rate of use" customer demand characteristic when discussing the cause of cost incurrence.

Q. WHAT IS THE SIGNIFICANCE OF THE DESIGN DAY DEMAND?

A. It is necessary first and foremost to safely and reliably meet the simultaneous loads of all customers. Furthermore, transmission plant is built to meet the highest

simultaneous peak established by customers. Therefore, the class contribution to the coincident design day demand is the appropriate cost causative factor to be used in the allocation of capital cost carrying charges of facilities to customer classes.

Q. WHAT ARE THE GENERAL PRINCIPLES THAT SHOULD GUIDE AN ANALYST IN PREPARING A CLASS COST OF SERVICE STUDY?

A. Allocation of costs among customer classes establishes the basis to measure existing revenue levels from such classes against the costs incurred by the Company to serve them. It also provides a basis for establishing actual tariff prices that will equitably recover the costs associated with providing service while minimizing inter-class subsidies that may otherwise occur. In brief, using the class cost of service analysis, the analyst allocates costs to cost causers. The costs that a utility incurs to serve customers are the transmission facilities to transmit the natural gas to town border stations, distribution facilities to distribute the natural gas to homes and businesses, general facilities that provide support to the first two functional groups and the related costs of operation.

Some analysts utilize energy use in a class cost of service to distribute capital costs to classes. These analysts rationalize this allocation methodology by pointing out that these facilities serve year-round load. This methodology gives no weight to the critical point that these facilities were sized and built to meet the highest demand that occurs during the winter period for Atmos Energy.

During the five winter months of November through March (the winter heating season), Atmos Energy can be expected to distribute about 74 percent of its total firm sales volumes. This vividly illustrates that the use of a design day

allocation methodology links cost incurrence and the cost causer for demand-related fixed costs.

Energy-related costs such as odorant vary with the actual throughput and should be spread to the various classes based on test year throughput. Costs such as services, regulators, meters, operation and maintenance of these facilities, customer accounting and other similar costs can be linked to given customer classes and should be allocated to and collected from those classes.

b. The Classification Study

Q. PLEASE DESCRIBE THE CLASSIFICATION STUDIES.

A. The classification studies I prepared for the Company follow the general guidelines established above. It is easiest to present the details associated with this process by introducing the specific studies I have conducted. Exhibit PHR-2 contains the complete customer/demand cost of service study (including the classifications developed) for Atmos Energy. The first five pages of the study contain summaries of the completed cost of service for total and customer-, demand-, and commodity-related costs. Pages 6 through 19 of the study contain summaries of the cost classifications employed. Pages 6 through 18 contain classification schedules for Gross Plant in Service, Reserve for Depreciation and Amortization, Other Rate Base, O&M Expense, Depreciation Expense, and Taxes Other Than Income and Net Deductions for Income Tax, respectively. Page 19 summarizes the classifications developed. Exhibit PHR-3 (the demand-only study) and Exhibit PHR-4 (the energy/demand study) are organized in the same way.

Q. PLEASE DESCRIBE YOUR CLASSIFICATION OF GROSS PLANT IN SERVICE.

A. As shown on pages 6-8 of Exhibit PHR-2, most of the gross plant in service accounts (general plant) are classified using an internally generated composite factor, developed from the classification of all production, storage, transmission, and distribution plant. Investments in transmission plant are classified as 100% demand-related and investments in storage facilities are classified as 50% demand and 50% commodity. Both classifications are consistent with those used in the Company's last base rate proceeding. In this study, investments in distribution mains and related facilities are classified as approximately 59% customer and 41% demand, in accordance with the results of a minimum system study.

The demand-only study (Exhibit PHR-3) changes the distribution mains and related facilities classification to 100% demand and the energy/demand study (Exhibit PHR-4) changes the classification of investments in distribution mains as approximately 56% demand and 44% commodity, based on the calculated load factor of the system. Of course, as these alternative classification schemes are applied, the internally generated composite factors also change to reflect more heavily the classification chosen for distribution mains and related facilities.

Q. PLEASE DESCRIBE YOUR CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION.

A. As shown on pages 9-11 of the class cost of service study, the classifications of the Reserves for Depreciation and Amortization follow the same classifications as employed for Gross Plant in Service, by study, since the same factors that influence

Gross Plant in Service also affect the Reserves for Depreciation of those plant categories.

Q. PLEASE DESCRIBE YOUR CLASSIFICATION OF OTHER RATE BASE ITEMS.

A. Other Rate Base items include materials and supplies, gas storage inventory, prepayments, cash working capital, customer advances and accumulated deferred income taxes and these amounts are classified in the same way across all studies. Materials and supplies, prepayments and cash working capital are classified in the same way as operations and maintenance expenditures. Gas storage inventories are classified as 100% commodity related. Customer advances are classified as a customer-related cost and accumulated deferred income taxes are classified according to net plant, since they would appear to be largely driven by these investments.

Q. PLEASE DESCRIBE YOUR CLASSIFICATION OF OPERATIONS AND MAINTENANCE (O&M) EXPENSES.

A. As can be seen on pages 13-14 of the studies, I have generally classified O&M expenses in accordance with the NARUC classification models and the same across all three studies. For example, other gas supply expenses have been classified as 100% commodity related. Underground storage O&M expenses are classified in the same way as investments in storage plant, i.e., 50% demand-related and 50% commodity-related.

Transmission O&M expense is classified as entirely demand-related. Distribution O&M expense classifications rely on customers for those expenses

related to services, regulators and meters and composite classification factors for many of the other accounts that make up distribution O&M expenses. These composite factors are generated within the class cost of service model. A&G expenses are also classified based on composite classification factors. Customer accounts expenses, customer service and information expenses and sales expenses are all classified as customer related.

Q. PLEASE DESCRIBE YOUR CLASSIFICATION OF DEPRECIATION AND AMORTIZATION EXPENSE.

A. Functionalized depreciation and amortization expense is shown on pages 15-17 of the class cost of service study. Functionalized depreciation expense is classified the same as gross plant. Of course, this changes with the classification of distribution mains and related facilities depreciation expense across the studies to be consistent with the way that each study classifies investments in these facilities.

Q. PLEASE DESCRIBE YOUR CLASSIFICATION OF TAXES, OTHER THAN INCOME TAXES.

A. Taxes other than income taxes fall into two categories, ad valorem and payroll related. Ad valorem taxes are classified based on plant while the various payroll-related taxes, most notably FICA taxes, are classified based on total O&M expenses. Total O&M expenses are also used to classify the DOT transmission user tax and other taxes. The Public Service Commission Assessment is classified as commodity related. Finally, while not a tax, the taxes other than income taxes schedule includes a classification of interest expense, a deduction to income taxes. Income taxes are computed elsewhere in the program. These classifications are

shown on Page 18 of the class cost of service studies and utilize the same classification factors across all studies.

c. The Allocation Study

Q. PLEASE DESCRIBE THE ALLOCATION STUDY.

A. The allocation schedules of the cost-of-service study begin on page 20 of the class cost of service studies. Each allocation section consists of four subsections. The first subsection shows the allocation of the functionalized cost item's customer component, the second subsection shows the allocation of the item's demand component, the third the commodity component, and the fourth the total allocated costs. Thus, for example, pages 20-22 contain the allocation of gross plant customer-related costs, pages 23-25 gross plant demand-related costs, pages 26-28 gross plant commodity-related costs and pages 29-31 total allocated gross plant.

Each line lists the functionalized cost item, the allocation factor used, the total company classified costs for that item, and the amount allocated of that cost item to each of the rate classes. These pages continue through page 71 of the exhibit. The allocation of revenue follows on page 72. Page 73 shows the classification factors used in the study, while pages 74 and 75 show the allocation factors used.

Q. PLEASE DESCRIBE THE PRIMARY ALLOCATION FACTORS THAT YOU HAVE USED IN YOUR STUDY.

A. There are three types of allocation factors used in this study. As is the case with the classification studies discussed above, these allocation factors are related to customers on the system, demands placed on the system, and energy demanded

from the system.

Q. PLEASE DESCRIBE THE ALLOCATORS OF CUSTOMER-RELATED COSTS THAT YOU USE.

A. Three primary allocators are used to assign customer-related costs to customer classes: the number of bills, customer-weighted meter investments, and direct assignment to the five individual customer classes. I used these different allocators because different customer-related costs are more appropriately allocated with each.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Certainly. The number of customers by class is used to allocate such expense items as sales and customer service and information costs. Meter investments are the best allocator for investment in meters. Industrial measuring and regulating station expenses are most appropriately assigned directly to non-residential sales and transport customers.

Q. PLEASE DESCRIBE THE ALLOCATORS OF DEMAND-RELATED COSTS THAT YOU USE.

A. The two demand allocators used are a class's design day peak, since design day forms the basis for planning decisions made by the Company and winter volumes, used to allocate storage expenses.

Q. PLEASE DESCRIBE THE ALLOCATORS OF COMMODITY-RELATED COSTS THAT YOU USE.

A. The primary allocator for commodity-related costs is total throughput.

Q. PLEASE SUMMARIZE YOUR ALLOCATION STUDIES.

A. The results are provided on lines 34 and 35 of the first page of each class cost of service study and summarized on Exhibit PHR-5. Page 1 of Exhibit PHR-5 shows actual and relative returns at present rates, the increases needed for an equalized proposed return by class and the estimated customer-related costs for the Company and for each of the cost-of-service classes for each of the studies developed. This information is provided for the customer/demand study on lines 1-6, for the demand-only study on lines 7-12, and the energy/demand study on lines 13-18. Page 2 of the exhibit summarizes these results to show the minimum, maximum and average revenue increases required by class to produce an equalized rate of return from the three studies on lines 1-6. Similar information related to the customer component of costs identified in each of the studies is provided on lines 7-12.

Q. WHY ARE THESE AMOUNTS OF INTEREST TO THE COMMISSION?

A. One of the primary purposes of a class cost of service analysis is to identify interclass subsidies that may exist between the different classes of a natural gas distribution system so that steps can be taken to eliminate them. This exhibit identifies for the Commission the extent to which rates need to be adjusted so that all identified subsidies can be eliminated under a range of reasonable allocation assumptions.

Q. DOES THE REVENUE INCREASE ALLOCATION ADVOCATED BY COMPANY WITNESS BRANNON TAYLOR MOVE THE CLASSES CLOSER TO AN EQUALIZED RATE OF RETURN?

A. Yes. This can be seen by comparing the class relative rates of return at proposed rates (line 56 of page 1 of Exhibits PHR-2, PHR-3, and PHR-4) to the class relative rates of return at existing rates (line 35 of page 1 of those same exhibits). If the class relative rates of return at proposed rates move closer to 1.0, the proposed revenue increase is a movement toward parity of class returns and a reduction of interclass subsidies. As this condition generally prevails across all classes and studies, I would conclude that the Company's proposed revenue distribution is a reasonable movement toward reducing interclass subsidies.

In addition, the Company's proposed revenue increases by class are generally within the range of increases suggested by all the studies, as shown on lines 1-6 in the last column of page 2 of Exhibit PHR-5. While alternative revenue distributions could also be supported, the Company's proposals appear to be reasonable and reflect gradualism in the assignment of the revenue increase.

Q. DOES THE EXHIBIT PROVIDE ANY OTHER SUPPORT FOR MR. TAYLOR'S RATE DESIGNS?

A. Yes. Mr. Taylor proposes customer charges for Residential Sales Customers of $24.40/month and $66.50/month for Non-Residential Sales Customers. In both cases, the levels of these charges are lower than the lowest fixed costs indicated by all the studies, as shown on lines 8 and 9 of Page 2 of Exhibit PHR-5.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Paul H. Raab, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Paul H. Raab

STATE OF MARYLAND

COUNTY OF ~~ANNE ARUNDEL~~ Howard MJ

SUBSCRIBED AND SWORN to before me by Paul H. Raab on this the 21st day of September, 2024.

MARK JOHNSON
Notary Public-Maryland
Howard County
My Commission Expires
July 08, 2028

Notary Public

My Commission Expires: July 08, 2028

PAUL H. RAAB

Mr. Raab's consulting focus is on the regulated public utility industry. His experience includes mathematical and economic analyses and system development and his areas of expertise include regulatory change management, load forecasting, supply-side and demand-side planning, management audits, mergers and acquisitions, costing and rate design, and depreciation and life analysis.

PROFESSIONAL EXPERIENCE

Mr. Raab has directed or has had a key role in numerous engagements in the areas listed above. Representative clients are provided for each of these areas in the subsections below.

Regulatory Change Management. Mr. Raab has recently been assisting both electric and natural gas utilities as they prepare to operate in an environment that is significantly different from the one they operate in today. This work has involved the development of unbundled cost of service studies; the development of strategies that will allow companies to prosper in a restructured industry; retail access program development, implementation, and evaluation; and the development of innovative ratemaking approaches to accompany changes in the regulatory structure. Representative clients for whom he has performed such work include:

- Texas Gas Service
- Virginia Natural Gas
- UGI Utilities, Inc. – Gas Division, UGI Penn Natural Gas, Inc., and UGI Central Penn Gas, Inc.
- The Peoples Natural Gas Company d/b/a Dominion Peoples
- National Fuel Gas Distribution Corporation
- Columbia Gas of Pennsylvania, Inc.
- Aquila
- Kansas Corporation Commission
- Atmos Energy Corporation
- Electric Cooperatives' Association
- Cleco
- Washington Gas
- Western Resources
- Kansas Gas Service
- Mid Continent Market Center.

Load Forecasting. Mr. Raab has broad experience in the review and development of forecasts of sales forecasts for electric and natural gas utilities. This work has also included the development of elasticity of demand measures that have been used for attrition adjustments and revenue requirement reconciliations. Representative clients for whom he has performed such work include:

- Washington Gas Energy Services
- Central Louisiana Electric Company
- Washington Gas
- Saskatchewan Public Utilities Review Commission
- Union Gas Limited
- Nova Scotia Power Corporation
- Cajun Electric Power Cooperative
- Cincinnati Gas & Electric
- Commonwealth Edison Company
- Cleveland Electric Illuminating
- Public Service of Indiana
- Atlantic City Electric Company
- Detroit Edison Company
- Sierra Pacific Power
- Connecticut Natural Gas Corporation
- Appalachian Power Company
- Missouri Public Service Company
- Empire District Electric Company
- Public Service Company of Oklahoma
- Wisconsin Electric Power Company
- Northern States Power Company
- Iowa State Commerce Commission
- Missouri Public Service Commission.

Supply Side Planning. Mr. Raab has assisted clients to determine the most appropriate supply-side resources to meet future demands. This assistance has included the determination of optimal sizes and types of capacity to install, determination of production costs including and excluding the resource, and an assessment of system reliability changes because of different resource additions. Much of this work for the following clients has been done in conjunction with litigation:

- Enstar Natural Gas
- AGL Resources
- Washington Gas
- Soyland Electric Cooperative
- Houston Lighting and Power
- City of Farmington, New Mexico
- Big Rivers Electric Cooperative
- City of Redding, California
- Brown & Root
- Kentucky Joint Committee on Electric Power Planning Coordination
- Sierra Pacific Power.

Demand Side Planning. Demand Side Planning involves the forecasting of future demands; the design, development, implementation, and evaluation of demand side management programs; the determination of future supply side costs; and the integration

of cost-effective demand side management programs into an Integrated Least Cost Resource Plan. Mr. Raab has performed such work for the following clients:

- UGI Utilities
- Dominion Peoples Gas
- National Fuel Gas Distribution Corporation
- Columbia Gas of Pennsylvania
- Kansas Gas Service
- Atmos Energy Corporation
- Black Hills Gas Company
- Oklahoma Natural Gas Company
- Washington Gas Light Company
- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- Montana-Dakota Utilities.

Management Audits. Mr. Raab has been involved in several management audits. Consistent with his other experience, the focus of his efforts has been in the areas of load forecasting, demand- and supply-side planning, integrated resource planning, sales and marketing, and rates. Representative commission/utility clients are as follows:

- Arizona Corporation Commission/Arizona Public Service Company
- Public Utilities Commission of Ohio/East Ohio Gas
- Kentucky Public Service Commission/Louisville Gas & Electric
- New Hampshire Public Service Commission/Public Service Company of New Hampshire
- New Mexico Public Service Commission/Public Service of New Mexico
- New York Public Service Commission/New York State Electric & Gas
- Missouri Public Service Commission/Laclede Gas Company
- New Jersey Board of Public Utilities/Jersey Central Power & Light
- New Jersey Board of Public Utilities/New Jersey Natural Gas
- Pennsylvania Public Utilities Commission/ Pennsylvania Power & Light
- California Public Utilities Commission/San Diego Gas & Electric Company.

Mergers and Acquisitions. Mr. Raab has been involved in several merger and acquisition studies throughout his career. Many of these were conducted as confidential studies and cannot be listed. Those in which his involvement was publicly known are:

- ONEOK, Inc./Southwest Gas Corporation
- Western Resources
- Constellation.

Costing and Rate Design Analysis. Mr. Raab has prepared generic rate design studies for the National Governor's Conference, the Electricity Consumer's Resource Council, the Tennessee Valley Industrial Committee, the State Electricity Commission of

Western Australia, and the State Electricity Commission of Victoria. These generic studies addressed advantages and disadvantages of alternative costing approaches in the electric utility industry; the strengths and weaknesses of commonly encountered costing methodologies; future tariff policies to promote equity, efficiency, and fairness criteria; and the advisability of changing tariff policies. Mr. Raab has performed specific costing and rate design studies for the following companies:

- New Mexico Gas
- SEMCO Gas
- Enstar Natural Gas
- Atmos Energy Corporation
- Southern Maryland Electric Cooperative, Inc.
- Comcast Cable Communications, Inc.
- Cable Television Association of Georgia
- Devon Energy
- Aquila
- Oklahoma Natural Gas
- Semco Energy Gas Company
- Laclede Gas
- Western Resources
- Kansas Gas Service Company
- Central Louisiana Electric Company
- Washington Gas Light Company
- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- KPL Gas Service Company
- Allegheny Power Systems
- Northern States Power
- Interstate Power Company
- Iowa-Illinois Gas & Electric Company
- Arkansas Power and Light
- Iowa Power & Light
- Iowa Public Service Company
- Southern California Edison
- Pacific Gas & Electric
- New York State Electric & Gas
- Middle South Utilities
- Missouri Public Service Company
- Empire District Electric Company
- Sierra Pacific Power
- Commonwealth Edison Company
- South Carolina Electric & Gas
- State Electricity Commission of Western Australia
- State Electricity Commission of Victoria, Australia
- Public Service Company of New Mexico

- Tennessee Valley Authority.

Depreciation and Life Analysis. Mr. Raab has extensive experience in depreciation and life analysis studies for the electric, gas, rail, and telephone industries and has taught a course on depreciation at George Washington University, Washington, DC. Representative clients in this area include:

- Champaign Telephone Company
- Plains Generation & Transmission Cooperative
- CSX Corporation (Includes work for Seaboard Coast Line, Louisville & Nashville, Baltimore & Ohio, Chesapeake & Ohio, and Western Maryland Railroads)
- Lea County Electric Cooperative, Inc.
- North Carolina Electric Membership Cooperative
- Alberta Gas Trunk Lines (NOVA)
- Federal Communications Commission.

TESTIMONY

The following table summarizes Mr. Raab's testimony experience.

Jurisdiction	Docket Number	Subject
Alaska	U-09-069, U-09-070	Rate Design
	U-14-010	Rate Design
Colorado	14AL-0300G	Costing/Rate Design
	17AL-0363G	Costing/Rate Design
	19AL-0309G	Costing/Rate Design
	22AL-0046G	Costing/Rate Design
District of Columbia	834	Demand Side Planning
	905	Costing/Rate Design
	917	Costing/Rate Design
	921	Demand Side Planning
	922	Rate Design
	934	Rate Design
	989	Rate Design
	1016	Rate Design
	1053	Costing/Rate Design
	1054	Costing/Rate Design
	1079	Rate Design
	1093	Costing/Rate Design
	1137	Costing/Rate Design
	1162	Costing/Rate Design
	1169	Costing/Rate Design

Jurisdiction	Docket Number	Subject
Georgia	18300-U	Costing/Rate Design
Indiana	36818	Capacity Planning
Iowa	RPU-05-2	Costing/Rate Design
Kansas	174,155-U	Retail Competition
	176,716-U	Costing/Rate Design
	98-KGSG-822-TAR	Rate Design
	99-KGSG-705-GIG	Restructuring
	01-KGSG-229-TAR	Rate Design
	02-KGSG-018-TAR	Rate Design
	02-WSRE-301-RTS	Cost of Service
	03-KGSG-602-RTS	Cost of Service/Rate Design
	03-AQLG-1076-TAR	Rate Design
	05-AQLG-367-RTS	Cost of Service/Rate Design
	06-KGSG-1209-RTS	Cost of Service/Rate Design
	07-AQLG-431-RTS	Rate Design
	08-WSEE-1041-RTS	Cost of Service
	10-KCPE-415-RTS	Cost of Service/Rate Design
	10-KGSG-421-TAR	Demand Side Planning
	10-KCPE-795-TAR	Demand Side Planning
	12-WSEE-112-RTS	Cost of Service/Rate Design
	12-KGSG-835-RTS	Cost of Service/Rate Design
	12-GIMX-337-GIV	Demand Side Planning
	12-KG&E-718-CON	Cost of Service
	13-KG&E-451-CON	Cost of Service
	13-WSEE-629-RTS	Cost of Service/Rate Design
	14-ATMG-320-RTS	Cost of Service/Rate Design
	15-WSEE-181-TAR	Demand Side Planning
	15-KCPE-116-RTS	Cost of Service/Rate Design
	16-ATMG-079-RTS	Cost of Service/Rate Design
	16-KGSG-491-RTS	Cost of Service/Rate Design
	16-KCPE-446-TAR	Demand Side Planning
	18-KCPE-480-RTS	Cost of Service/Rate Design
	18-KGSG-560-RTS	Cost of Service/Rate Design
	19-ATMG-525-RTS	Cost of Service/Rate Design
	22-EKME-254-TAR	Demand Side Planning
	23-ATMG-359-RTS	Cost of Service/Rate Design
	23-EKCE-775-RTS	Cost of Service/Rate Design
	24-KGSG-610-RTS	Cost of Service/Rate Design

Jurisdiction	Docket Number	Subject
Kentucky	9613	Capacity Planning
	97-083	Management Audit
	2009-00354	Cost of Service
	2013-00148	Cost of Service
	2015-00343	Cost of Service
	2017-00349	Cost of Service
	2018-00281	Cost of Service
	2021-00214	Cost of Service
Louisiana	U-21453	Restructuring/Market Power
Maryland	8251	Costing/Rate Design
	8259	Demand Side Planning
	8315	Costing/Rate Design
	8720	Demand Side Planning
	8791	Costing/Rate Design
	8920	Costing/Rate Design
	8959	Costing/Rate Design
	9092	Costing/Rate Design
	9104	Costing/Rate Design
	9106	Costing/Rate Design
	9180	Capacity Planning
	9267	Costing/Rate Design
	9433	Capacity Planning
	9481	Costing
	9651	Costing/Rate Design
	9704	Costing/Rate Design
Michigan	U-6949	Load Forecasting
	U-13575	Costing/Rate Design
	U-16169	Costing/Rate Design
	U-20479	Costing/Rate Design
Missouri	GR-2002-356	Rate Design
Montana	D2005.4.48	Costing/Rate Design
Nebraska	NG-0001, NG-0002, NG-0003	Rate Design
	NG-0041	Rate Design
Nevada	81-660	Load Forecasting
New Jersey	OAL# PUC 1876-82	Load Forecasting

Jurisdiction	BPU# 822-0116 Docket Number	Subject
New Mexico	2087	Capacity Planning
	11-00042-UT	Rate Design
New York	27546	Costing/Rate Design
Ohio	81-1378-EL-AIR	Load Forecasting
Oklahoma	27068	Load Forecasting
	PUD 200400610	Costing/Rate Design
	PUD 200700449	Demand Side Planning
	PUD 200800348	Costing/Rate Design
	PUD 200900110	Costing/Rate Design
	PUD 201000143	Demand Side Planning
	PUD 201100170	Demand Side Planning
	PUD 201200029	Demand Side Planning
	PUD 201300007	Demand Side Planning
	PUD 201300032	Demand Side Planning
	PUD 201400069	Demand Side Planning
	PUD 201500138	Demand Side Planning
	PUD 201500213	Costing/Rate Design
	PUD 201600132	Demand Side Planning
	PUD 201700079	Demand Side Planning
	PUD 201800028	Demand Side Planning
	PUD 201900018	Demand Side Planning
	PUD 201900021	Demand Side Planning
	PUD 202000022	Demand Side Planning
	PUD 202100062	Demand Side Planning
	PUD 202100063	Costing/Rate Design
	PUD 202200023	Demand Side Planning
	PUD 202200036	Demand Side Planning
	PUD 202300012	Demand Side Planning
	PUD 202400010	Demand Side Planning

Jurisdiction	Docket Number	Subject
Pennsylvania	R-0061346	Costing/Rate Design
	M-2009-2092222, M-2009-2112952, M-2009-2112956	Demand Side Planning
	M-2009-2093216	Demand Side Planning
	M-2009-2093217	Demand Side Planning
	M-2009-2093218	Demand Side Planning
	M-2010-2210316	Demand Side Planning
	R-2010-2214415	Demand Side Planning
	M-2012-2334387, M-2012-2334392, M-2012-2334398	Demand Side Planning
	M-2012-2334388	Demand Side Planning
	M-2015-2177174	Demand Side Planning
Tennessee	PURPA Hearings	Costing/Rate Design
US Tax Court	4870	Life Analysis
	4875	Life Analysis
Texas	GUD No. 9762	Costing/Rate Design
	GUD No. 10170	Costing/Rate Design
	GUD No. 10174	Costing/Rate Design
	GUD No. 10506	Demand Side Planning
	GUD No. 10526	Demand Side Planning
	GUD No. 10779	Costing/Rate Design
	GUD No. 10928	Costing/Rate Design
	OS-22-00009896	Costing/Rate Design
	Case No.00014399	Costing/Rate Design

Jurisdiction	Docket Number	Subject
Virginia	PUE900013	Demand Side Planning
	PUE920041	Costing/Rate Design
	PUE940030	Costing/Rate Design
	PUE940031	Costing/Rate Design
	PUE950131	Capacity Planning
	PUE980813	Costing/Rate Design
	PUE-2002-00364	Costing/Rate Design
	PUE-2003-00603	Costing/Rate Design
	PUE-2006-00059	Costing/Rate Design
	PUE-2008-00060	Demand Side Planning
	PUE-2009-00064	Demand Side Planning
	PUE-2012-00118	Demand Side Planning
	PUE-2015-00132	Demand Side Planning
	PUE-2015-00138	Demand Side Planning
	PUE-2016-00001	Capacity Planning
	PUR-2018-00080	Capacity Planning
	PUR-2018-00193	Demand Side Planning
	PUR-2021-00288	Demand Side Planning
	PUR-2022-00054	Costing/Rate Design
West Virginia	79-140-E-42T	Capacity Planning
	90-046-E-PC	Demand Side Planning
Wisconsin	05-EP-2	Capacity Planning

In addition, Mr. Raab has presented expert testimony before the Federal Energy Regulatory Commission, the Pennsylvania House Consumer Affairs Committee, the Michigan House Economic Development and Energy Committee and the Province of Saskatchewan. He has also served on the Advisory Board of the Expert Evidence Report, published by The Bureau of National Affairs, Inc.

EDUCATION

Mr. Raab holds a B.A. (with high distinction) in Economics from Rutgers University and an M.A. from SUNY at Binghamton with a concentration in Econometrics. While attending Rutgers, he studied as a Henry Rutgers Scholar.

PUBLICATIONS AND PRESENTATIONS

Mr. Raab has published in several professional journals and spoken at several industry conferences. His publications/ presentations include:

- "Natural Gas as an Electric DSM Tool," American Gas Association Membership Services Committee Meeting, Williamsburg, VA, September 15, 2009.

- "Electric-to-Gas Fuel Switching," NARUC Summer Meeting, Seattle, WA, July 20, 2009.

- "The Future of Fuel in Virginia: Natural Gas," The Twenty-Seventh National Regulatory Conference, Williamsburg, VA, May 19, 2009.

- "Revenue Decoupling for Natural Gas Utilities," Energy Bar Association Midwest Energy Conference, Chicago, IL, March 6, 2008.

- "Responses to Arrearage Problems from High Natural Gas Bills," American Gas Association Rate and Regulatory Issues Seminar, Phoenix, AZ, April 8, 2004.

- "Factors Influencing Cooperative Power Supply," National Rural Utilities Cooperative Finance Corporation Independent Borrower's Conference, Boston, MA, July 3, 1997.

- "Current Status of LDC Unbundling," American Gas Association Unbundling Conference: Regulatory and Competitive Issues, Arlington, VA, June 19, 1997.

- "Balancing, Capacity Assignment, and Stranded Costs," American Gas Association Rate and Strategic Planning Committee Spring Meeting, Phoenix, AZ, March 26, 1997.

- "Gas Industry Restructuring and Changes: The Relationship of Economics and Marketing" (with Jed Smith), National Association of Business Economists, 38th Annual Meeting, Boston, MA September 10, 1996.

- "Improving Corporate Performance By Better Forecasting," 1996 Peak Day Demand and Supply Planning Seminar, San Francisco, CA, April 11, 1996.

- "Natural Gas Price Elasticity Estimation," AGA Forecasting Review, Vol. 6, No. 1, November 1995.

- "Assessing Price Competitiveness," Competitive Analysis & Benchmarking for Power Companies, Washington, DC, November 13, 1995.

- "Avoided Cost Concepts and Management Considerations," Workshop on Avoided Costs in a Post 636 Gas Industry: Is It Time to Unbundle Avoided Cost? Sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, Milwaukee, WI, June 29, 1994.

- "Estimating Implied Long- and Short-Run Price Elasticities of Natural Gas Consumption," Atlantic Economic Conference, Philadelphia, PA, October 10, 1993.

- "Program Evaluation and Marginal Cost," The Natural Gas Least Cost Planning Conference, Washington, DC, April 7, 1992.
- "The New Environmentalism & Least Cost Planning," Institute for Environmental Negotiation, University of Virginia, May 15, 1991.
- "Development of Conditional Demand Estimates of Gas Appliances," AGA Forecasting Review, Vol. 1, No. 1, October 1988.
- "The Feasibility Study: Forecasting and Sensitivities," Municipal Wastewater Treatment Facilities, The Energy Bureau, Inc., November 18, 1985.
- "The Development of a Gas Sales End-Use Forecasting Model," Third International Forecasting Symposium, The International Institute of Forecasting, July 1984.
- "New Forecasting Guidelines for REC's - A Seminar," (Chairman), Kansas City, Missouri, June 1984.
- "A Method and Application of Estimating Long Run Marginal Cost for an Electric Utility," Advances in Microeconomics, Volume II, 1983.
- "Forecasting Under Public Scrutiny," Forecasting Energy and Demand Requirements, University of Wisconsin - Extension, October 25, 1982.
- "Forecasting Public Utilities," The Journal of Business Forecasting, Vol. 1, No. 4, Summer, 1982.
- "Are Utilities Underforecasting," Electric Ratemaking, Vol. 1. No. 1, February 1982.
- "A Polynomial Spline Function Technique for Defining and Forecasting Electric Utility Load Duration Curves," First International Forecasting Symposium, Montreal, Canada, May 1981.
- "Time-of-Use Rates and Marginal Costs," ELCON Legal Seminar, March 20, l980.
- "The Ernst & Whinney Forecasting Model," Forecasting Energy & Demand Requirements, University of Wisconsin - Extension, October 8, l979.
- "Marginal Cost in Electric Utilities - A Multi-Technology Multi-Period Analysis" (with Frederick McCoy), ORSA/Tims Joint National Meeting, Los Angeles, California, November 13-15, 1978.

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF RESULTS

			Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
			$					
8	Operating Revenues		187,822,013	104,985,875	63,700,770	1,079,146	9,593,772	8,462,450
10	Operating Expenses:							
12	Operating & Maintenance		120,959,622	75,179,326	43,056,740	852,785	1,594,170	276,602
13	Depreciation & Amortization		22,028,375	16,508,658	4,623,580	7,240	775,680	113,218
14	Taxes Other Than Income		13,731,224	9,971,555	3,001,994	12,484	605,640	139,551
16	Total Operating Expenses		156,719,221	101,659,538	50,682,314	872,508	2,975,490	529,371
18	Income Before Taxes		31,102,792	3,326,337	13,018,456	206,638	6,618,282	7,933,079
20	Interest Expense		10,240,350	7,649,452	2,037,133	2,763	462,079	88,923
22	Income Taxes:							
24	State Income Taxes	5.00%	1,043,122	(216,156)	549,066	10,194	307,810	392,208
25	Federal Income Taxes	21.00%	4,162,057	(862,461)	2,190,774	40,673	1,228,162	1,564,909
25	Total Deferred Income Taxes		0	0	0	0	0	0
26	Amortization of ITC		0	0	0	0	0	0
28	Total Income Taxes		5,205,179	(1,078,617)	2,739,840	50,867	1,535,973	1,957,117
30	Net Income		25,897,613	4,404,954	10,278,616	155,771	5,082,309	5,975,962
32	Total Rate Base		628,233,491	469,284,905	124,975,725	169,497	28,348,014	5,455,350
34	Rate of Return		4.1223%	0.9387%	8.2245%	91.9021%	17.9283%	109.5431%
35	Relative Rate of Return		1.00	0.23	2.00	22.29	4.35	26.57
37	Equalized ROR:		52,143,380	38,950,647	10,372,985	14,068	2,352,885	452,794
39	Net Income Increase		26,245,767	34,545,693	94,369	(141,703)	(2,729,424)	(5,523,168)
40	Uncollectibles/PSC Fees Increase	1.1554%	408,778	538,050	1,470	(2,207)	(42,511)	(86,023)
41	Income Taxes		8,725,275	11,484,544	31,373	(47,108)	(907,383)	(1,836,150)
42	Gross Revenue After Increase		223,201,833	151,554,162	63,827,981	888,128	5,914,454	1,017,108
43	Revenue Deficiency		35,379,820	46,568,287	127,211	(191,019)	(3,679,318)	(7,445,341)
44	Rate of Return		8.3000%	8.3000%	8.3000%	8.3000%	8.3000%	8.3000%
45	Relative Rate of Return		1.00	1.00	1.00	1.00	1.00	1.00
46	Percent Increase		18.8369%	44.3567%	0.1997%	-17.7009%	-38.3511%	-87.9809%
48	Proposed Rate Levels:							
50	Net Income Increase		26,245,662	14,909,209	5,905,961	65,857	3,229,532	2,135,103
51	Uncollectibles/PSC Fees Increase		408,777	232,211	91,985	1,026	50,300	33,254
52	Income Taxes		8,725,240	4,956,492	1,963,408	21,894	1,073,642	709,804
53	Gross Revenue After Increase		223,201,693	125,083,788	71,662,124	1,167,924	13,947,246	11,340,611
54	Revenue Deficiency		35,379,679	20,097,912	7,961,354	88,777	4,353,474	2,878,162
55	Rate of Return		8.3000%	4.1157%	12.9502%	130.7567%	29.3207%	148.6809%
56	Relative Rate of Return		1.00	0.50	1.56	15.75	3.53	17.91
57	Percent Increase		18.8368%	19.1434%	12.4981%	8.2266%	45.3781%	34.0110%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF CUSTOMER COSTS

		Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
		$					
1	Rate Base	429,929,614	366,757,040	61,437,887	76,784	1,034,857	623,046
2							
3	Return @ Realized ROR	17,722,950	4,894,421	6,041,126	104,985	2,721,003	3,961,415
4	O&M Expenses	21,877,272	18,736,808	3,065,663	3,302	44,705	26,794
5	Depreciation Expense	16,616,188	13,647,709	2,851,724	5,168	69,652	41,935
6	Taxes, Other	8,747,489	7,368,057	1,337,451	1,858	25,045	15,077
7							
8	Interest Expense	7,007,952	5,978,224	1,001,452	1,252	16,868	10,156
9							
10	Income Taxes:						
11							
12	State Income Taxes	713,857	(72,205)	335,754	6,911	180,156	263,242
13	Federal Income Taxes	2,848,291	(288,099)	1,339,660	27,575	718,821	1,050,335
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	3,562,148	(360,305)	1,675,415	34,486	898,976	1,313,577
18							
19	Total Customer-Related Costs @ Realized ROR	68,526,047	44,286,691	14,971,378	149,799	3,759,381	5,358,798
20	Total Customers	180,768	160,460	20,110	9	118	71
21	Customer Costs ($/customer/month)	$ 31.59	$ 23.00	$ 62.04	$ 1,426.66	$ 2,656.52	$ 6,289.67
22							
23							
24	Incremental Return @ Equalized ROR	17,961,208	25,546,413	(941,781)	(98,612)	(2,635,110)	(3,909,702)
25	Incremental Income Taxes	5,971,114	8,492,778	(313,090)	(32,783)	(876,029)	(1,299,761)
26	Incremental Uncollectibles/PSC Fees Increase	279,746	397,886	(14,668)	(1,536)	(41,042)	(60,894)
27							
28	Total Customer-Related Costs @ Equalized ROR	92,738,115	78,723,768	13,701,838	16,868	207,200	88,441
29	Customers	180,768	160,460	20,110	9	118	71
30	Dollars/Customer/Month	$ 42.75	$ 40.88	$ 56.78	$ 160.65	$ 146.42	$ 103.80
31							
32							
33	Incremental Return @ Proposed Rates	17,961,136	12,108,239	3,035,368	43,431	1,442,886	1,331,212
34	Incremental Income Taxes	5,971,091	4,025,324	1,009,093	14,438	479,680	442,555
35	Incremental Uncollectibles/PSC Fees Increase	279,745	188,586	47,276	676	22,473	20,734
36							
37	Total Customer-Related Costs @ Proposed Rates	92,738,019	60,608,840	19,063,115	208,345	5,704,421	7,153,298
38	Customers	180,768	160,460	20,110	9	118	71
39	Dollars/Customer/Month	$ 42.75	$ 31.48	$ 78.99	$ 1,984.24	$ 4,030.95	$ 8,395.89

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF DEMAND COSTS

		Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
		$					
1	Rate Base	179,596,976	96,973,977	59,846,839	0	22,776,160	0
2							
3	Return @ Realized ROR	7,403,510	(273,536)	3,932,677	42,534	2,057,739	1,644,096
4	O&M Expenses	10,395,048	5,612,840	3,463,927	0	1,318,281	0
5	Depreciation Expense	5,028,686	2,715,256	1,675,702	0	637,729	0
6	Taxes, Other	3,661,714	1,977,154	1,220,188	0	464,372	0
7							
8	Interest Expense	2,927,472	1,580,698	975,517	0	371,257	0
9							
10	Income Taxes:						
11							
12	State Income Taxes	298,204	(123,533)	197,013	2,834	112,357	109,533
13	Federal Income Taxes	1,189,833	(492,898)	786,081	11,306	448,306	437,038
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	1,488,037	(616,431)	983,093	14,140	560,663	546,571
18							
19	Total Demand-Related Costs @ Realized ROR	27,976,995	9,415,283	11,275,587	56,674	5,038,784	2,190,667
20							
21							
22	Incremental Return @ Equalized ROR	7,503,039	8,322,376	1,034,610	(42,534)	(167,318)	(1,644,096)
23	Incremental Income Taxes	2,494,348	2,766,733	343,951	(14,140)	(55,624)	(546,571)
24	Incremental Uncollectibles/PSC Fees Increase	116,860	129,621	16,114	(662)	(2,606)	(25,607)
25							
26	Total Demand-Related Costs @ Equalized ROR	38,091,242	20,634,013	12,670,262	(662)	4,813,236	(25,607)
27							
28							
29	Incremental Return @ Proposed Rates	7,503,009	2,708,780	2,696,002	16,803	1,536,203	545,222
30	Incremental Income Taxes	2,494,338	900,520	896,272	5,586	510,703	181,256
31	Incremental Uncollectibles/PSC Fees Increase	116,860	42,189	41,990	262	23,926	8,492
32							
33	Total Demand-Related Costs @ Proposed Rates	38,091,202	13,066,773	14,909,851	79,324	7,109,616	2,925,637

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF COMMODITY COSTS

		Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
		$					
1	Rate Base	18,706,901	5,553,889	3,690,998	92,713	4,536,997	4,832,304
2							
3	Return @ Realized ROR	771,153	228,947	152,154	3,822	187,028	199,202
4	O&M Expenses	88,687,302	50,829,677	36,527,151	849,483	231,184	249,808
5	Depreciation Expense	383,501	145,693	96,154	2,072	68,299	71,284
6	Taxes, Other	1,322,021	626,343	444,356	10,626	116,224	124,473
7							
8	Interest Expense	304,927	90,530	60,164	1,511	73,954	78,768
9							
10	Income Taxes:						
11							
12	State Income Taxes	31,061	9,222	6,129	154	7,533	8,024
13	Federal Income Taxes	123,934	36,795	24,453	614	30,058	32,014
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	154,995	46,016	30,581	768	37,591	40,038
18							
19	Total Commodity-Related Costs	91,318,971	51,876,677	37,250,395	866,770	640,326	684,804
20	Total Throughput	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
21	Commodity Costs ($/Mcf)		$ 5.21972	$ 5.21553	$ 4.07480	$ 0.08095	$ 0.08
22							
23							
24	Incremental Return @ Equalized ROR	781,520	232,025	154,199	3,873	189,543	201,880
25	Incremental Income Taxes	259,812	77,136	51,263	1,288	63,012	67,114
26	Incremental Uncollectibles/PSC Fees Increase	12,172	3,614	2,402	60	2,952	3,144
27							
28	Total Commodity-Related Costs @ Equalized ROR	92,372,476	52,189,452	37,458,259	871,991	895,833	956,942
29	Total Throughput	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
30	Commodity Costs ($/Mcf)	$ 2.73	$ 5.25	$ 5.24	$ 4.10	$ 0.11	$ 0.11
31							
32							
33	Incremental Return @ Proposed Rates	781,517	(352,689)	327,251	10,054	366,982	429,919
34	Incremental Income Taxes	259,811	(117,250)	108,793	3,342	122,001	142,924
35	Incremental Uncollectibles/PSC Fees Increase	12,172	(5,493)	5,097	157	5,716	6,696
36							
37	Total Commodity-Related Costs @ Proposed Rates	92,372,472	51,401,245	37,691,536	880,323	1,135,024	1,264,343
38	Total Throughput	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
39	Commodity Costs ($/Mcf)	$ 2.73	$ 5.17	$ 5.28	$ 4.14	$ 0.14	$ 0.15

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

TOTAL COST OF SERVICE

		Total Company $	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Rate Base	628,233,491	469,284,905	124,975,725	169,497	28,348,014	5,455,350
2							
3	Return @ Realized ROR	25,897,613	4,849,833	10,125,957	151,341	4,965,770	5,804,712
4	O&M Expenses	120,959,622	75,179,326	43,056,740	852,785	1,594,170	276,602
5	Depreciation Expense	22,028,375	16,508,658	4,623,580	7,240	775,680	113,218
6	Taxes, Other	13,731,224	9,971,555	3,001,994	12,484	605,640	139,551
7							
8	Interest Expense	10,240,350	7,649,452	2,037,133	2,763	462,079	88,923
9							
10	Income Taxes:						
11							
12	State Income Taxes	1,043,122	(186,517)	538,896	9,899	300,046	380,799
13	Federal Income Taxes	4,162,057	(744,203)	2,150,194	39,495	1,197,184	1,519,387
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	5,205,179	(930,720)	2,689,089	49,394	1,497,230	1,900,186
18							
19	Total Cost of Service @ Realized ROR	187,822,013	105,578,651	63,497,360	1,073,243	9,438,490	8,234,269
20							
21							
22	Incremental Return @ Equalized ROR	26,245,767	34,100,814	247,028	(137,273)	(2,612,885)	(5,351,918)
23	Incremental Income Taxes	8,725,275	11,336,647	82,123	(45,636)	(868,641)	(1,779,219)
24	Incremental Uncollectibles/PSC Fees Increase	408,778	531,121	3,847	(2,138)	(40,696)	(83,356)
25							
26	Total Cost of Service @ Equalized ROR	223,201,833	151,547,233	63,830,359	888,197	5,916,269	1,019,775
27							
28							
29	Incremental Return @ Proposed Rates	26,245,662	14,464,330	6,058,621	70,288	3,346,071	2,306,353
30	Incremental Income Taxes	8,725,240	4,808,595	2,014,158	23,367	1,112,385	766,736
31	Incremental Uncollectibles/PSC Fees Increase	408,777	225,282	94,363	1,095	52,115	35,921
32							
33	Total Cost of Service @ Proposed Rates	223,201,693	125,076,859	71,664,502	1,167,993	13,949,061	11,343,278

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF GROSS PLANT IN SERVICE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Intangible Plant:						
2								
3	30100	Organization	8,330	5.4	P, S, T & D Plant	5,755	2,402	173
4	30200	Franchises & Consents	119,853	5.4	P, S, T & D Plant	82,800	34,556	2,496
5	30300	Misc Intangible Plant	-	99.0	-	-	-	-
6								
7		Total Intangible Plant:	128,182			88,555	36,958	2,670
8								
9		Production Plant:						
10								
11	32520	Producing Leaseholds	-	99.0	-	-	-	-
12	32540	Rights of Ways	-	99.0	-	-	-	-
13	33100	Production Gas Wells Equipment	-	99.0	-	-	-	-
14	33201	Field Lines	-	99.0	-	-	-	-
15	33202	Tributary Lines	-	99.0	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	-	99.0	-	-	-	-
17	33600	Purification Equipment	-	99.0	-	-	-	-
18								
19		Total Production Plant	-			0	0	0
20								
21		Storage Plant:						
22								
23	35010	Land	261,127	3.5	Storage (50/50)	-	130,563	130,563
24	35020	Rights of Way	4,682	3.5	Storage (50/50)	-	2,341	2,341
25	35100	Structures and Improvements	17,916	3.5	Storage (50/50)	-	8,958	8,958
26	35102	Compression Station Equipment	223,508	3.5	Storage (50/50)	-	111,754	111,754
27	35103	Meas. & Reg. Sta. Structues	23,138	3.5	Storage (50/50)	-	11,569	11,569
28	35104	Other Structures	137,443	3.5	Storage (50/50)	-	68,721	68,721
29	35200	Wells \ Rights of Way	12,534,611	3.5	Storage (50/50)	-	6,267,306	6,267,306
30	35201	Well Construction	1,699,999	3.5	Storage (50/50)	-	849,999	849,999
31	35202	Well Equipment	667,359	3.5	Storage (50/50)	-	333,680	333,680
32	35203	Cushion Gas	1,694,833	3.5	Storage (50/50)	-	847,416	847,416
33	35210	Leaseholds	178,530	3.5	Storage (50/50)	-	89,265	89,265
34	35211	Storage Rights	54,614	3.5	Storage (50/50)	-	27,307	27,307
35	35301	Field Lines	175,350	3.5	Storage (50/50)	-	87,675	87,675
36	35302	Tributary Lines	209,319	3.5	Storage (50/50)	-	104,659	104,659
37	35400	Compressor Station Equipment	18,065,905	3.5	Storage (50/50)	-	9,032,953	9,032,953
38	35500	Meas & Reg. Equipment	273,084	3.5	Storage (50/50)	-	136,542	136,542
39	35600	Purification Equipment	1,327,498	3.5	Storage (50/50)	-	663,749	663,749
40								
41		Total Storage Plant	37,548,916			0	18,774,458	18,774,458
42								
43		Transmission:						
44								
45	36510	Land & Land Rights	26,970	2.0	Demand	-	26,970	-
46	36520	Rights of Way	867,772	2.0	Demand	-	867,772	-
47	36602	Structures & Improvements	397,833	2.0	Demand	-	397,833	-
48	36603	Other Structues	60,826	2.0	Demand	-	60,826	-
49	36700	Mains Cathodic Protection	47,233	2.0	Demand	-	47,233	-
50	36701	Mains - Steel	27,826,921	2.0	Demand	-	27,826,921	-
51	36703	Mains - Anodes	11,134	2.0	Demand	-	11,134	-
52	36900	Meas. & Reg. Equipment	1,999,587	2.0	Demand	-	1,999,587	-
53	36901	Meas. & Reg. Equipment	2,269,499	2.0	Demand	-	2,269,499	-
54								
55		Total Transmission Plant	33,507,777			0	33,507,777	0
56								
57		Distribution:						
58								
59	37400	Land & Land Rights	613,356	4.0	Mains (Minimum System)	363,026	250,330	-
60	37401	Land	428,640	4.0	Mains (Minimum System)	253,699	174,942	-
61	37402	Land Rights	4,157,536	4.0	Mains (Minimum System)	2,460,713	1,696,823	-
62	37403	Land Other	2,784	4.0	Mains (Minimum System)	1,648	1,136	-
63	37500	Structures & Improvements	336,168	4.0	Mains (Minimum System)	198,967	137,201	-
64	37501	Structures & Improvements T.B.	99,818	4.0	Mains (Minimum System)	59,079	40,739	-
65	37502	Land Rights	46,264	4.0	Mains (Minimum System)	27,382	18,882	-
66	37503	Improvements	4,005	4.0	Mains (Minimum System)	2,370	1,635	-
67	37600	Mains Cathodic Protection	3,418,283	4.0	Mains (Minimum System)	2,023,173	1,395,110	-
68	37601	Mains - Steel	230,553,919	4.0	Mains (Minimum System)	136,457,527	94,096,392	-
69	37602	Mains - Plastic	221,659,304	4.0	Mains (Minimum System)	131,193,087	90,466,216	-
70	37603	Mains - Anodes	3,599,610	4.0	Mains (Minimum System)	2,130,495	1,469,116	-
71	37604	Mains - Leak Clamps	6,789,879	4.0	Mains (Minimum System)	4,018,713	2,771,166	-
72	37800	Meas & Reg. Sta. Equip - General	25,594,946	4.0	Mains (Minimum System)	15,148,834	10,446,112	-
73	37900	Meas & Reg. Sta. Equip - City Gate	9,712,761	4.0	Mains (Minimum System)	5,748,674	3,964,087	-
74	37905	Meas & Reg. Sta. Equipment T.b.	1,718,293	4.0	Mains (Minimum System)	1,017,003	701,290	-
75	38000	Services	193,916,542	1.0	Customer	193,916,542	-	-
76	38100	Meters	55,920,540	1.0	Customer	55,920,540	-	-
77	38200	Meter Installations	61,761,518	1.0	Customer	61,761,518	-	-
78	38300	House Regulators	3,974,497	1.0	Customer	3,974,497	-	-
79	38400	House Reg. Installations	378,094	1.0	Customer	378,094	-	-
80	38500	Ind. Meas. & Reg. Sta. Equipment	5,725,878	1.0	Customer	5,725,878	-	-
81	38600	Other Prop. On Cust. Prem	-	99.0	-	-	-	-
82								
83		Total Distribution Plant	830,412,635			622,781,459	207,631,176	0
84								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF GROSS PLANT IN SERVICE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
85		General:						
86								
87	38900	Land & Land Rights	1,211,697	5.4	P, S, T & D Plant	837,103	349,359	25,235
88	39000	Structures & Improvements	9,256,964	5.4	P, S, T & D Plant	6,395,188	2,668,986	192,790
89	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
90	39002	Structures-Brick	173,115	5.4	P, S, T & D Plant	119,597	49,913	3,605
91	39003	Improvements	876,634	5.4	P, S, T & D Plant	605,624	252,753	18,257
92	39004	Air Conditioning Equipment	12,955	5.4	P, S, T & D Plant	8,950	3,735	270
93	39009	Improvement to leased Premises	1,267,195	5.4	P, S, T & D Plant	875,444	365,360	26,391
94	39100	Office Furniture & Equipment	1,816,939	5.4	P, S, T & D Plant	1,255,235	523,863	37,840
95	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
96	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
97	39200	Transportation Equipment	180,749	5.4	P, S, T & D Plant	124,871	52,114	3,764
98	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
99	39202	Trailers	36,588	5.4	P, S, T & D Plant	25,277	10,549	762
100	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
101	39400	Tools, Shop & Garage Equipment	7,143,379	5.4	P, S, T & D Plant	4,935,014	2,059,593	148,772
102	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
103	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
104	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
105	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
106	39700	Communication Equipment	433,938	5.4	P, S, T & D Plant	299,787	125,114	9,037
107	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
108	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
109	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
110	39800	Miscellaneous Equipment	2,982,913	5.4	P, S, T & D Plant	2,060,750	860,039	62,124
111	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
112	39901	Other Tangible Property - Servers - H/W	21,425	5.4	P, S, T & D Plant	14,802	6,177	446
113	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
114	39903	Other Tangible Property - Network - H/W	-	5.4	P, S, T & D Plant	-	-	-
115	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
116	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
117	39906	Other Tang. Property - PC Hardware	530,662	5.4	P, S, T & D Plant	366,608	153,001	11,052
118	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
119	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
120	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
121	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
122								
123		Total General Plant	25,945,153			17,924,249	7,480,558	540,347
124								
125		TOTAL DIRECT PLANT	927,542,664			640,794,263	267,430,926	19,317,475
126								
127		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
128								
129		Kentucky Mid-States General Office:						
130								
131		Intangible Plant:						
132								
133	30100	Organization	92,599	5.4	P, S, T & D Plant	63,972	26,698	1,929
134	30200	Franchises & Consents	-	5.4	P, S, T & D Plant	-	-	-
135	30300	Misc Intangible Plant	554,443	5.4	P, S, T & D Plant	383,038	159,858	11,547
136								
137		Total Intangible Plant:	647,042			447,010	186,556	13,476
138								
139		General:						
140								
141	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
142	39001	Structures Frame	89,615	5.4	P, S, T & D Plant	61,911	25,838	1,866
143	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
144	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
145	39004	Air Conditioning Equipment	7,687	5.4	P, S, T & D Plant	5,311	2,216	160
146	39009	Improvement to leased Premises	19,405	5.4	P, S, T & D Plant	13,406	5,595	404
147	39100	Office Furniture & Equipment	13,456	5.4	P, S, T & D Plant	9,296	3,880	280
148	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
149	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
150	39200	Transportation Equipment	2,054	5.4	P, S, T & D Plant	1,419	592	43
151	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
152	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
153	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
154	39400	Tools, Shop & Garage Equipment	55,081	5.4	P, S, T & D Plant	38,053	15,881	1,147
155	39600	Power Operated Equipment	4,736	5.4	P, S, T & D Plant	3,272	1,366	99
156	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
157	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
158	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
159	39700	Communication Equipment	-	5.4	P, S, T & D Plant	-	-	-
160	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
161	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
162	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
163	39800	Miscellaneous Equipment	-	5.4	P, S, T & D Plant	-	-	-
164	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
165	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
166	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
167	39903	Other Tangible Property - Network - H/W	14,125	5.4	P, S, T & D Plant	9,758	4,072	294
168	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
169	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
170	39906	Other Tang. Property - PC Hardware	-	5.4	P, S, T & D Plant	-	-	-
171	39907	Other Tang. Property - PC Software	21,748	5.4	P, S, T & D Plant	15,025	6,270	453
172	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
173	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
174	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
175								
176		Total General Plant	227,907			157,450	65,711	4,747
177								
178		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
179								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF GROSS PLANT IN SERVICE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
180		Shared Services General Office:						
181								
182		General:						
183								
184	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
185	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
186	36602	Structures & Improvements	483,221	5.4	P, S, T & D Plant	333,834	139,323	10,064
187	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
188	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
189	39009	Improvement to leased Premises	642,376	5.4	P, S, T & D Plant	443,787	185,211	13,378
190	39100	Office Furniture & Equipment	384,176	5.4	P, S, T & D Plant	265,409	110,767	8,001
191	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
192	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
193	39200	Transportation Equipment	14,389	5.4	P, S, T & D Plant	9,941	4,149	300
194	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
195	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
196	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
197	39400	Tools, Shop & Garage Equipment	1,375	5.4	P, S, T & D Plant	950	396	29
198	39500	Tools, Shop & Garage Equipment	-	5.4	P, S, T & D Plant	-	-	-
199	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
200	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
201	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
202	39700	Communication Equipment	35,202	5.4	P, S, T & D Plant	24,319	10,149	733
203	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
204	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
205	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
206	39800	Miscellaneous Equipment	5,516	5.4	P, S, T & D Plant	3,811	1,590	115
207	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
208	39901	Other Tangible Property - Servers - H/W	2,628,270	5.4	P, S, T & D Plant	1,815,744	757,788	54,738
209	39902	Other Tangible Property - Servers - S/W	2,115,244	5.4	P, S, T & D Plant	1,461,320	609,871	44,053
210	39903	Other Tangible Property - Network - H/W	292,050	5.4	P, S, T & D Plant	201,763	84,205	6,082
211	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
212	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
213	39906	Other Tang. Property - PC Hardware	214,855	5.4	P, S, T & D Plant	148,433	61,947	4,475
214	39907	Other Tang. Property - PC Software	3,774	5.4	P, S, T & D Plant	2,607	1,088	79
215	39908	Other Tang. Property - Mainframe S/W	4,940,307	5.4	P, S, T & D Plant	3,413,019	1,424,399	102,889
216	39909	Other Tang. Property - Application Software	1,654,844	5.4	P, S, T & D Plant	1,143,252	477,128	34,465
217	39931	Other Tang. Property - ALGN	799,338	5.4	P, S, T & D Plant	552,224	230,467	16,647
218								
219		Total General Plant	14,214,939			9,820,412	4,098,479	296,048
220								
221		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
222								
223		Shared Services Customer Support:						
224								
225		General:						
226								
227	37400	Land & Land Rights	211,229	5.4	P, S, T & D Plant	145,928	60,902	4,399
228	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
229	36602	Structures & Improvements	1,107,950	5.4	P, S, T & D Plant	765,429	319,446	23,075
230	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
231	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
232	39009	Improvement to leased Premises	170,931	5.4	P, S, T & D Plant	118,088	49,283	3,560
233	39100	Office Furniture & Equipment	176,418	5.4	P, S, T & D Plant	121,879	50,865	3,674
234	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
235	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
236	39200	Transportation Equipment	2,237	5.4	P, S, T & D Plant	1,546	645	47
237	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
238	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
239	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
240	39400	Tools, Shop & Garage Equipment	21,259	5.4	P, S, T & D Plant	14,687	6,129	443
241	39510	Laboratory Equip	-	5.4	P, S, T & D Plant	-	-	-
242	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
243	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
244	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
245	39700	Communication Equipment	105,908	5.4	P, S, T & D Plant	73,167	30,536	2,206
246	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
247	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
248	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
249	39800	Miscellaneous Equipment	29,842	5.4	P, S, T & D Plant	20,616	8,604	621
250	39900	Other Tangible Property	8,234	5.4	P, S, T & D Plant	5,689	2,374	171
251	39901	Other Tangible Property - Servers - H/W	304,635	5.4	P, S, T & D Plant	210,458	87,833	6,344
252	39902	Other Tangible Property - Servers - S/W	98,374	5.4	P, S, T & D Plant	67,962	28,363	2,049
253	39903	Other Tangible Property - Network - H/W	35,543	5.4	P, S, T & D Plant	24,555	10,248	740
254	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
255	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
256	39906	Other Tang. Property - PC Hardware	93,706	5.4	P, S, T & D Plant	64,737	27,018	1,952
257	39907	Other Tang. Property - PC Software	98	5.4	P, S, T & D Plant	68	28	2
258	39908	Other Tang. Property - Mainframe S/W	5,800,519	5.4	P, S, T & D Plant	4,007,298	1,672,417	120,805
259	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
260	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
261								
262		Total General Plant	8,166,885			5,642,105	2,354,692	170,088
263								
264		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
265								
266		TOTAL PLANT IN SERVICE	950,799,437			656,861,240	274,136,365	19,801,832
267								
268		TOTAL CWIP W/O AFUDC	-			0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Intangible Plant:						
2								
3	30100	Organization	8,330	5.4	P, S, T & D Plant	5,755	2,402	173
4	30200	Franchises & Consents	119,853	5.4	P, S, T & D Plant	82,800	34,556	2,496
5	30300	Misc Intangible Plant	-	99.0	-	-	-	-
6								
7		Total Intangible Plant:	128,182			88,555	36,958	2,670
8								
9		Production Plant:						
10								
11	32520	Producing Leaseholds	-	99.0	-	-	-	-
12	32540	Rights of Ways	-	99.0	-	-	-	-
13	33100	Production Gas Wells Equipment	-	99.0	-	-	-	-
14	33201	Field Lines	-	99.0	-	-	-	-
15	33202	Tributary Lines	-	99.0	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	-	99.0	-	-	-	-
17	33600	Purification Equipment	-	99.0	-	-	-	-
18								
19		Total Production Plant	-			0	0	0
20								
21		Storage Plant:						
22								
23	35010	Land	-	3.5	Storage (50/50)	-	-	-
24	35020	Rights of Way	4,200	3.5	Storage (50/50)	-	2,100	2,100
25	35100	Structures and Improvements	7,863	3.5	Storage (50/50)	-	3,931	3,931
26	35102	Compression Station Equipment	120,440	3.5	Storage (50/50)	-	60,220	60,220
27	35103	Meas. & Reg. Sta. Structues	20,864	3.5	Storage (50/50)	-	10,432	10,432
28	35104	Other Structures	106,003	3.5	Storage (50/50)	-	53,002	53,002
29	35200	Wells \ Rights of Way	2,463,749	3.5	Storage (50/50)	-	1,231,874	1,231,874
30	35201	Well Construction	1,502,528	3.5	Storage (50/50)	-	751,264	751,264
31	35202	Well Equipment	474,361	3.5	Storage (50/50)	-	237,180	237,180
32	35203	Cushion Gas	702,999	3.5	Storage (50/50)	-	351,499	351,499
33	35210	Leaseholds	167,328	3.5	Storage (50/50)	-	83,664	83,664
34	35211	Storage Rights	44,691	3.5	Storage (50/50)	-	22,346	22,346
35	35301	Field Lines	105,566	3.5	Storage (50/50)	-	52,783	52,783
36	35302	Tributary Lines	153,747	3.5	Storage (50/50)	-	76,873	76,873
37	35400	Compressor Station Equipment	682,172	3.5	Storage (50/50)	-	341,086	341,086
38	35500	Meas & Reg. Equipment	167,060	3.5	Storage (50/50)	-	83,530	83,530
39	35600	Purification Equipment	322,628	3.5	Storage (50/50)	-	161,314	161,314
40								
41		Total Storage Plant	7,046,197			0	3,523,099	3,523,099
42								
43		Transmission:						
44								
45	36510	Land & Land Rights	-	2.0	Demand	-	-	-
46	36520	Rights of Way	587,414	2.0	Demand	-	587,414	-
47	36602	Structures & Improvements	29,122	2.0	Demand	-	29,122	-
48	36603	Other Structues	62,894	2.0	Demand	-	62,894	-
49	36700	Mains Cathodic Protection	33,163	2.0	Demand	-	33,163	-
50	36701	Mains - Steel	18,044,112	2.0	Demand	-	18,044,112	-
51	36703	Mains - Anodes	11,180	2.0	Demand	-	11,180	-
52	36900	Meas. & Reg. Equipment	620,559	2.0	Demand	-	620,559	-
53	36901	Meas. & Reg. Equipment	2,023,747	2.0	Demand	-	2,023,747	-
54								
55		Total Transmission Plant	21,412,190			0	21,412,190	0
56								
57		Distribution:						
58								
59	37400	Land & Land Rights	-	4.0	Mains (Minimum System)	-	-	-
60	37401	Land	-	4.0	Mains (Minimum System)	-	-	-
61	37402	Land Rights	644,160	4.0	Mains (Minimum System)	381,258	262,902	-
62	37403	Land Other	-	4.0	Mains (Minimum System)	-	-	-
63	37500	Structures & Improvements	136,375	4.0	Mains (Minimum System)	80,716	55,659	-
64	37501	Structures & Improvements T.B.	81,770	4.0	Mains (Minimum System)	48,397	33,373	-
65	37502	Land Rights	40,711	4.0	Mains (Minimum System)	24,096	16,615	-
66	37503	Improvements	2,204	4.0	Mains (Minimum System)	1,305	900	-
67	37600	Mains Cathodic Protection	1,792,334	4.0	Mains (Minimum System)	1,060,826	731,509	-
68	37601	Mains - Steel	30,950,942	4.0	Mains (Minimum System)	18,318,878	12,632,065	-
69	37602	Mains - Plastic	28,052,270	4.0	Mains (Minimum System)	16,603,246	11,449,024	-
70	37603	Mains - Anodes	1,851,162	4.0	Mains (Minimum System)	1,095,644	755,518	-
71	37604	Mains - Leak Clamps	5,615,083	4.0	Mains (Minimum System)	3,323,389	2,291,694	-
72	37800	Meas & Reg. Sta. Equip - General	5,288,177	4.0	Mains (Minimum System)	3,129,903	2,158,273	-
73	37900	Meas & Reg. Sta. Equip - City Gate	1,456,651	4.0	Mains (Minimum System)	862,145	594,506	-
74	37905	Meas & Reg. Sta. Equipment T.b.	1,068,358	4.0	Mains (Minimum System)	632,327	436,031	-
75	38000	Services	38,828,841	1.0	Customer	38,828,841	-	-
76	38100	Meters	23,998,006	1.0	Customer	23,998,006	-	-
77	38200	Meter Installaitons	22,719,274	1.0	Customer	22,719,274	-	-
78	38300	House Regulators	469,350	1.0	Customer	469,350	-	-
79	38400	House Reg. Installations	130,024	1.0	Customer	130,024	-	-
80	38500	Ind. Meas. & Reg. Sta. Equipment	3,090,645	1.0	Customer	3,090,645	-	-
81	38600	Other Prop. On Cust. Prem	-	99.0	-	-	-	-
82								
83		Total Distribution Plant	166,216,337			134,798,268	31,418,069	0
84								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
85		General:						
86								
87	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
88	39000	Structures & Improvements	1,968,463	5.4	P, S, T & D Plant	1,359,916	567,551	40,996
89	39002	Structures - Brick	118,817	5.4	P, S, T & D Plant	82,085	34,257	2,475
90	39003	Improvements	335,075	5.4	P, S, T & D Plant	231,487	96,610	6,978
91	39003	Air Conditioning Equipment	8,916	5.4	P, S, T & D Plant	6,159	2,571	186
92	39004	Improvement to Leased Premises	1,267,195	5.4	P, S, T & D Plant	875,444	365,360	26,391
93	39009	Office Furniture & Equipment	1,473,706	5.4	P, S, T & D Plant	1,018,112	424,902	30,692
94	39100	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
95	39102	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
96	39103	Transportation Equipment	75,817	5.4	P, S, T & D Plant	52,378	21,860	1,579
97	39200	Trucks	-	5.4	P, S, T & D Plant	-	-	-
98	39201	Trailers	8,658	5.4	P, S, T & D Plant	5,981	2,496	180
99	39202	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
100	39400	Tools, Shop & Garage Equipment	3,345,740	5.4	P, S, T & D Plant	2,311,410	964,650	69,680
101	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
102	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
103	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
104	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
105	39700	Communication Equipment	366,653	5.4	P, S, T & D Plant	253,303	105,714	7,636
106	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
107	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
108	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
109	39800	Miscellaneous Equipment	1,548,948	5.4	P, S, T & D Plant	1,070,093	446,596	32,259
110	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
111	39901	Other Tangible Property - Servers - H/W	21,595	5.4	P, S, T & D Plant	14,919	6,226	450
112	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
113	39903	Other Tangible Property - Network - H/W	-	5.4	P, S, T & D Plant	-	-	-
114	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
115	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
116	39906	Other Tang. Property - PC Hardware	530,003	5.4	P, S, T & D Plant	366,154	152,812	11,038
117	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
118	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
119	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
120		Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
121		Retirement Work in Progress	(1,655,581)	5.4	P, S, T & D Plant	(1,143,760)	(477,340)	(34,480)
122		AR 15 general plant amortization	-	5.4	P, S, T & D Plant	-	-	-
123								
124		Total General Plant	9,414,005			6,503,680	2,714,264	196,061
125								
126		TOTAL DIRECT RESERVE FOR DEPRECIATION	204,216,911			141,390,503	59,104,580	3,721,829
127								
128		Kentucky Mid-States General Office:						
129								
130		Intangible Plant:						
131								
132	30100	Organization	-	5.4	P, S, T & D Plant	-	-	-
133	30200	Franchises & Consents	-	5.4	P, S, T & D Plant	-	-	-
134	30300	Misc Intangible Plant	-	5.4	P, S, T & D Plant	-	-	-
135								
136		Total Intangible Plant:	-			0	0	0
137								
138		General:						
139								
140	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
141	39001	Structures Frame	60,032	5.4	P, S, T & D Plant	41,473	17,309	1,250
142	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
143	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
144	39004	Air Conditioning Equipment	7,666	5.4	P, S, T & D Plant	5,296	2,210	160
145	39009	Improvement to leased Premises	19,405	5.4	P, S, T & D Plant	13,406	5,595	404
146	39100	Office Furniture & Equipment	4,261	5.4	P, S, T & D Plant	2,943	1,228	89
147	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
148	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
149	39200	Transportation Equipment	(990)	5.4	P, S, T & D Plant	(684)	(286)	(21)
150	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
151	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
152	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
153	39400	Tools, Shop & Garage Equipment	26,914	5.4	P, S, T & D Plant	18,594	7,760	561
154	39600	Power Operated Equipment	1,496	5.4	P, S, T & D Plant	1,034	431	31
155	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
156	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
157	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
158	39700	Communication Equipment	(11,027)	5.4	P, S, T & D Plant	(7,618)	(3,179)	(230)
159	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
160	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
161	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
162	39800	Miscellaneous Equipment	(63,459)	5.4	P, S, T & D Plant	(43,841)	(18,297)	(1,322)
163	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
164	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
165	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
166	39903	Other Tangible Property - Network - H/W	9,760	5.4	P, S, T & D Plant	6,743	2,814	203
167	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
168	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
169	39906	Other Tang. Property - PC Hardware	-	5.4	P, S, T & D Plant	-	-	-
170	39907	Other Tang. Property - PC Software	21,748	5.4	P, S, T & D Plant	15,025	6,270	453
171	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
172	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
173	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
174		Retirement Work in Progress	26,243	5.4	P, S, T & D Plant	18,130	7,566	547
175								
176		Total General Plant	102,049			70,501	29,423	2,125
177								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
178		Shared Services General Office:						
179								
180		General:						
181								
182	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
183	39000	Structures & Improvements	158,337	5.4	P, S, T & D Plant	109,388	45,652	3,298
184	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
185	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
186	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
187	39009	Improvement to leased Premises	496,454	5.4	P, S, T & D Plant	342,976	143,139	10,339
188	39100	Office Furniture & Equipment	193,036	5.4	P, S, T & D Plant	133,359	55,656	4,020
189	39102	Remittance Processing Equip	0	5.4	P, S, T & D Plant	0	0	0
190	39103	Office Machines	0	5.4	P, S, T & D Plant	0	0	0
191	39200	Transportation Equipment	10,393	5.4	P, S, T & D Plant	7,180	2,996	216
192	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
193	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
194	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
195	39400	Tools, Shop & Garage Equipment	1,267	5.4	P, S, T & D Plant	875	365	26
196	39500	39500-Laboratory Equipment	-	5.4	P, S, T & D Plant	-	-	-
197	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
198	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
199	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
200	39700	Communication Equipment	7,704	5.4	P, S, T & D Plant	5,322	2,221	160
201	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
202	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
203	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
204	39800	Miscellaneous Equipment	2,531	5.4	P, S, T & D Plant	1,748	730	53
205	39900	Other Tangible Property	(0)	5.4	P, S, T & D Plant	(0)	(0)	(0)
206	39901	Other Tangible Property - Servers - H/W	595,292	5.4	P, S, T & D Plant	411,258	171,636	12,398
207	39902	Other Tangible Property - Servers - S/W	703,290	5.4	P, S, T & D Plant	485,869	202,774	14,647
208	39903	Other Tangible Property - Network - H/W	95,736	5.4	P, S, T & D Plant	66,139	27,603	1,994
209	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
210	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
211	39906	Other Tang. Property - PC Hardware	86,835	5.4	P, S, T & D Plant	59,990	25,036	1,808
212	39907	Other Tang. Property - PC Software	3,178	5.4	P, S, T & D Plant	2,196	916	66
213	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
214	39909	Other Tang. Property - Application Software	4,933,686	5.4	P, S, T & D Plant	3,408,445	1,422,490	102,751
215	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
216	ADJ	WTW Adjustment	9,173	5.4	P, S, T & D Plant	6,337	2,645	191
217								
218		Total General Plant	7,296,912			5,041,083	2,103,860	151,969
219								
220		Shared Services Customer Support:						
221								
222		General:						
223								
224	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
225	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
226	36602	Structures & Improvements	420,763	5.4	P, S, T & D Plant	290,685	121,315	8,763
227	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
228	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
229	39009	Improvement to leased Premises	136,913	5.4	P, S, T & D Plant	94,586	39,475	2,851
230	39100	Office Furniture & Equipment	99,042	5.4	P, S, T & D Plant	68,423	28,556	2,063
231	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
232	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
233	39200	Transportation Equipment	2,251	5.4	P, S, T & D Plant	1,555	649	47
234	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
235	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
236	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
237	39400	Tools, Shop & Garage Equipment	10,609	5.4	P, S, T & D Plant	7,329	3,059	221
238	39500	Laboratory Equipment	4	5.4	P, S, T & D Plant	3	1	0
239	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
240	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
241	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
242	39700	Communication Equipment	98,184	5.4	P, S, T & D Plant	67,831	28,309	2,045
243	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
244	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
245	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
246	39800	Miscellaneous Equipment	10,096	5.4	P, S, T & D Plant	6,975	2,911	210
247	39900	Other Tangible Property	(8,317)	5.4	P, S, T & D Plant	(5,746)	(2,398)	(173)
248	39901	Other Tangible Property - Servers - H/W	208,015	5.4	P, S, T & D Plant	143,708	59,975	4,332
249	39902	Other Tangible Property - Servers - S/W	99,003	5.4	P, S, T & D Plant	68,397	28,545	2,062
250	39903	Other Tangible Property - Network - H/W	17,716	5.4	P, S, T & D Plant	12,239	5,108	369
251	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
252	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
253	39906	Other Tang. Property - PC Hardware	34,234	5.4	P, S, T & D Plant	23,650	9,870	713
254	39907	Other Tang. Property - PC Software	(3,876)	5.4	P, S, T & D Plant	(2,678)	(1,118)	(81)
255	39908	Other Tang. Property - Mainframe S/W	4,158,816	5.4	P, S, T & D Plant	2,873,124	1,199,078	86,614
256	39909	Other Tang. Property - Application Software	5,952	5.4	P, S, T & D Plant	4,112	1,716	124
257	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
258		Retirement Work in Progress	-	5.4	P, S, T & D Plant	-	-	-
259								
260		Total General Plant	5,289,404			3,654,193	1,525,051	110,160
261								
262		TOTAL RESERVE FOR DEPRECIATION	216,905,276			150,156,279	62,762,914	3,986,083

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF OTHER RATE BASE

		Test Year	Classif.	Classif.	Customer	Demand	Commodity
		$	Factor	Basis	$	$	$
1	Rate Base Additions:						
2							
3	Materials and Supplies - KY Direct	(29,510)	9.1	Allocated O&M Expenses	(5,337)	(2,536)	(21,636)
4	Materials and Supplies - KY Mid-States GO	549,932	9.1	Allocated O&M Expenses	99,463	47,260	403,209
5	Materials and Supplies - Shared Services GO	14,276	9.1	Allocated O&M Expenses	2,582	1,227	10,467
6	Materials and Supplies - Shared Services CS	0	9.1	Allocated O&M Expenses	-	-	-
7	Gas Storage Inventory	9,182,907	3.0	Commodity	-	-	9,182,907
8	Prepayments - KY Direct	0	9.1	Allocated O&M Expenses	-	-	-
9	Prepayments - KY Mid-States GO	0	9.1	Allocated O&M Expenses	-	-	-
10	Prepayments - Shared Services GO	0	9.1	Allocated O&M Expenses	-	-	-
11	Prepayments - Shared Services CS	0	9.1	Allocated O&M Expenses	-	-	-
12	Cash Working Capital	(2,199,566)	9.1	Allocated O&M Expenses	(397,823)	(189,027)	(1,612,716)
13	Regulatory Assets/Liabilities	(3,720,791)	9.1	Allocated O&M Expenses	(672,958)	(319,758)	(2,728,075)
14							
15	Total Rate Base Additions	3,797,249			(974,073)	(462,834)	5,234,156
16							
17							
18	Rate Base Deductions:						
19							
20	Customer Advances - KY Direct	(736,136)	1.0	Customer	(736,136)	-	-
21	Customer Advances - KY Mid-States GO	0	1.0	Customer	-	-	-
22	Customer Advances - Shared Services GO	0	1.0	Customer	-	-	-
23	Customer Advances - Shared Services CS	0	1.0	Customer	-	-	-
24	ADIT - KY Direct (Div 009)	(94,613,910)	5.7	Net Plant	(65,324,593)	(27,250,344)	(2,038,972)
25	ADIT - Shared Services GO (Div 002)	(7,615,553)	5.7	Net Plant	(5,258,031)	(2,193,403)	(164,119)
26	ADIT - Shared Services CS (Div 012)	(492,256)	5.7	Net Plant	(339,870)	(141,778)	(10,608)
27	ADIT - KY Mid-States GO (Div 091)	(184,730)	5.7	Net Plant	(127,544)	(53,205)	(3,981)
28	Change in Net Operating Loss Carryforward	(5,815,333)	5.7	Net Plant	(4,015,100)	(1,674,910)	(125,323)
29							
30	Total Rate Base Deductions	(109,457,919)			(75,801,274)	(31,313,641)	(2,343,003)
31							
32							
33	TOTAL OTHER RB	(105,660,670)			(76,775,348)	(31,776,475)	2,891,152
34							
35	Interest on Customer Deposits	0	1.0	Customer	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF O&M EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Production & Gathering:						
2		Operation						
3	7500	Op., Sup., & Eng.	0	99.0	-	-	-	-
4	7510	Production Maps & Records	0	99.0	-	-	-	-
5	7530	Field Lines Expenses	0	99.0	-	-	-	-
6	7540	Field Compressor Station Expense	0	99.0	-	-	-	-
7	7550	Field Compressor Sta. Fuel & Pwr.	0	99.0	-	-	-	-
8	7560	Field Meas. & Regul. Station Exp	0	99.0	-	-	-	-
9	7570	Purification Expense	0	99.0	-	-	-	-
10	7590	Other Expenses	0	99.0	-	-	-	-
11		Maintenance						
12	7610	Maint. Sup., & Eng.	0	99.0	-	-	-	-
13	7620	Structures and Improvements	0	99.0	-	-	-	-
14	7640	Field Line Maintenance	0	99.0	-	-	-	-
15	7650	Compressor Station Equip. Maint.	0	99.0	-	-	-	-
16	7660	Meas. & Regul. Station Equip Maint	0	99.0	-	-	-	-
17	7670	Purification Equipment Maintenance	0	99.0	-	-	-	-
18	7680	Other Equipment Maintenance	0	99.0	-	-	-	-
19	7690	Gas Processed By Others	0	99.0	-	-	-	-
20		Total Production & Gathering	0			0	0	0
21								
22		Other Gas Supply Expenses:						
23		Operation						
24	8001	Intercompany Gas Well-head Purchases	0	3.0	Commodity	-	-	-
25	8010	Natural gas field line purchases	115,617	3.0	Commodity	-	-	115,617
26	8040	Natural gas city gate purchases	50,226,537	3.0	Commodity	-	-	50,226,537
27	8050	Transmission-Operation supervision and engineering	(29,531)	3.0	Commodity	-	-	(29,531)
28	8051	Other Gas Purchases / Gas Cost Adjustments	53,391,020	3.0	Commodity	-	-	53,391,020
29	8052	PGA for Commercial	30,150,016	3.0	Commodity	-	-	30,150,016
30	8053	PGA for Industrial	4,872,096	3.0	Commodity	-	-	4,872,096
31	8054	PGA for Public Authority	4,999,866	3.0	Commodity	-	-	4,999,866
32	8058	Unbilled PGA Cost	(5,763,929)	3.0	Commodity	-	-	(5,763,929)
33	8059	PGA Offset to Unrecovered Gas Cost	(109,657,357)	3.0	Commodity	-	-	(109,657,357)
34	8060	Exchange gas	(122,035)	3.0	Commodity	-	-	(122,035)
35	8081	Gas withdrawn from storage-Debit	30,798,939	3.0	Commodity	-	-	30,798,939
36	8082	Gas delivered to storage-Credit	(14,414,625)	3.0	Commodity	-	-	(14,414,625)
37	8120	Gas used for other utility operations-Credit	(8,172)	3.0	Commodity	-	-	(8,172)
38	8580	Transmission and compression of gas by others	43,082,454	3.0	Commodity	-	-	43,082,454
39		Maintenance						
40	8350	Maint. Of Purch. Gas Meas. Sta.	0	3.0	Commodity	-	-	-
41		Total Other Gas Supply Expenses	87,640,898			0	0	87,640,898
42								
43		Underground Storage:						
44		Operation						
45	8140	Storage-Operation supervision and engineering	0	3.5	Storage (50/50)	-	-	-
46	8160	Wells expenses	35,164	3.5	Storage (50/50)	-	17,582	17,582
47	8170	Lines expenses	22,782	3.5	Storage (50/50)	-	11,391	11,391
48	8180	Compressor station expenses	44,776	3.5	Storage (50/50)	-	22,388	22,388
49	8190	Compressor station fuel and power	0	3.5	Storage (50/50)	-	-	-
50	8200	Storage-Measuring and regulating station expenses	9,536	3.5	Storage (50/50)	-	4,768	4,768
51	8210	Storage-Purification expenses	83,940	3.5	Storage (50/50)	-	41,970	41,970
52	8240	Storage-Other expenses	0	3.5	Storage (50/50)	-	-	-
53	8250	Storage well royalties	10,482	3.5	Storage (50/50)	-	5,241	5,241
54	8260	Rents	0	3.5	Storage (50/50)	-	-	-
55		Maintenance						
56	8300	Maint. Sup., & Eng.	0	3.5	Storage (50/50)	-	-	-
57	8310	Structures and Improvements	0	3.5	Storage (50/50)	-	-	-
58	8320	Reservoirs & Wells Maintenance	0	3.5	Storage (50/50)	-	-	-
59	8330	Line Maintenance	0	3.5	Storage (50/50)	-	-	-
60	8340	Compressor Station Equip Maint	46,416	3.5	Storage (50/50)	-	23,208	23,208
61	8350	Meas. & Regul. Station Equip Maint	0	3.5	Storage (50/50)	-	-	-
62	8360	Purification Equipment Maintenance	0	3.5	Storage (50/50)	-	-	-
63	8410	Other storage expenses-Operation labor and expenses	233,243	3.5	Storage (50/50)	-	116,621	116,621
64		Total Underground Storage Expense	486,338			0	243,169	243,169
65								
66		Transmission:						
67		Operation						
68	8500	Op., Sup., & Eng.	0	2.0	Demand	-	-	-
69	8510	System Control & Load Dispatching	0	2.0	Demand	-	-	-
70	8520	Communication Systems Expense	0	2.0	Demand	-	-	-
71	8530	Compressor Station Labor Expense	0	2.0	Demand	-	-	-
72	8540	Compressor Station Fuel Gas	0	2.0	Demand	-	-	-
73	8550	Compressor Station Fuel & Power	488	2.0	Demand	-	488	-
74	8560	Mains Expense	145,499	2.0	Demand	-	145,499	-
75	8570	Meas. & Regul. Station Expenses	11,936	2.0	Demand	-	11,936	-
76	8580	LDC Payment	0	2.0	Demand	-	-	-
77	8580	LDC Payment - A&G	0	2.0	Demand	-	-	-
78	8590	Other Expenses	0	2.0	Demand	-	-	-
79	8600	Rents	0	2.0	Demand	-	-	-
80		Maintenance						
81	8610	Maint. Sup., & Eng.	0	2.0	Demand	-	-	-
82	8620	Structures and Improvements	0	2.0	Demand	-	-	-
83	8630	Mains	22,915	2.0	Demand	-	22,915	-
84	8640	Compressor Station Equip Maint	0	2.0	Demand	-	-	-
85	8650	Meas. & Regul. Station Equip Maint	0	2.0	Demand	-	-	-
86	8660	Communication Equipment Maintenance	0	2.0	Demand	-	-	-
87	8670	Other Equipment Maintenance	0	2.0	Demand	-	-	-
88		Total Transmission Expense	180,838			0	180,838	0
89								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF O&M EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
90		Distribution:						
91		Operation						
92	8700	Supervision and Engineering	2,140,705	10.0	Composite of Accts. 871-879 & 886-893	1,316,806	762,477	61,423
93	8710	Distribution Load Dispatching	(41)	3.0	Commodity	-	-	(41)
94	8711	Odorization	132,819	3.0	Commodity	-	-	132,819
94	8720	Compressor Station Labor & Expenses	0	3.0	Commodity	-	-	-
95	8740	Mains & Services	6,802,984	12.0	Composite of Accts. 374-379	4,026,470	2,776,514	-
96	8750	Measuring and Regulating Station Exp. - Gen	1,361,535	12.0	Composite of Accts. 374-379	805,849	555,686	-
97	8760	Measuring and Regulating Station Exp. - Ind.	523	1.0	Customer	523	-	-
98	8770	Measuring and Regulating Sta. Exp. - City Gate	5,487	12.0	Composite of Accts. 374-379	3,248	2,240	-
99	8780	Meters and House Regulator Expense	938,471	1.0	Customer	938,471	-	-
100	8790	Customer Installations Expense	257	1.0	Customer	257	-	-
101	8800	Other Expense	3,085	10.0	Composite of Accts. 871-879 & 886-893	1,898	1,099	89
102	8810	Rents	75,023	10.0	Composite of Accts. 871-879 & 886-893	46,148	26,722	2,153
103		Maintenance						
104	8850	Maintenance Supervision and Engineering	0	10.0	Composite of Accts. 871-879 & 886-893	-	-	-
105	8860	Maintenance of Structures and Improvements	0	12.0	Composite of Accts. 374-379	-	-	-
106	8870	Maintenance of Mains	144,480	12.0	Composite of Accts. 374-379	85,513	58,967	-
107	8890	Maintenance of compressor station equipment	140,590	3.0	Commodity	-	-	140,590
108	8900	Maint. of Measuring and Regulating Station Equip. - General	0	12.0	Composite of Accts. 374-379	-	-	-
109	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	135	1.0	Customer	135	-	-
110	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	178	12.0	Composite of Accts. 374-379	105	73	-
111	8930	Maintenance of Services	0	1.0	Customer	-	-	-
112	8940	Maintenance of Meters and House Regulators	0	1.0	Customer	-	-	-
113	8950	Maintenance of Other Equipment	0	10.0	Composite of Accts. 871-879 & 886-893	-	-	-
114		Total Distribution	11,746,231			7,225,423	4,183,777	337,032
115								
116		Customer Accounts:						
117	9010	Supervision	0	1.0	Customer	-	-	-
118	9020	Meter Reading Expense	735,288	1.0	Customer	735,288	-	-
119	9030	Customer Records and Collection Expenses	1,067,803	1.0	Customer	1,067,803	-	-
120	9040	Uncollectible Accounts	731,532	1.0	Customer	731,532	-	-
121	9050	Miscellaneous Customer Accounts Expenses	0	1.0	Customer	-	-	-
122		Total Customer Accounts	2,534,624			2,534,624	0	0
123								
124		Customer Service and Information:						
125	9070	Supervision	0	1.0	Customer	-	-	-
126	9080	Customer Assistance Expenses	0	1.0	Customer	-	-	-
127	9090	Informational and Instructional Advertising Expenses	214,461	1.0	Customer	214,461	-	-
128	9100	Miscellaneous Customer Service and Informational Expenses	0	1.0	Customer	-	-	-
129		Total Customer Service and Information	214,461			214,461	0	0
130								
131		Sales:						
132	9110	Supervision	158,549	1.0	Customer	158,549	-	-
133	9120	Demonstrating and Selling Expenses	77,078	1.0	Customer	77,078	-	-
134	9130	Advertising Expenses	36,821	1.0	Customer	36,821	-	-
135	9160	Miscellaneous Sales Expenses	(188,721)	1.0	Customer	(188,721)	-	-
136		Total Sales	83,728			83,728	0	0
137								
138		Administrative & General:						
139		Operation						
140	9200	Administrative and General Salaries	-	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	-	-	-
141	9210	Office Supplies and Expenses	69,069	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	44,948	22,323	1,798
142	9220	Administrative Expenses Transferred - Customer Support	-	1.0	Customer	-	-	-
143	9220	Administrative Expenses Transferred - General	18,251,309	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	11,877,417	5,898,711	475,181
144	9230	Outside Services Employed	69,993	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	45,549	22,621	1,822
145	9240	Property Insurance	-	5.7	Net Plant	-	-	-
146	9250	Injuries and Damages	23,257	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	15,135	7,517	606
147	9260	Employee Pensions and Benefits	872,759	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	567,966	282,070	22,723
148	9270	Franchise Requirements	635	1.0	Customer	635	-	-
149	9280	Regulatory Commission Expenses	165,392	1.0	Customer	165,392	-	-
150	930.1	General Advertising Expenses	-	1.0	Customer	-	-	-
151	930.2	Miscellaneous General Expense	24,411	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	15,886	7,889	636
152	ADJ	Adjustments	(1,404,321)	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	(913,891)	(453,868)	(36,562)
153		Maintenance						
154	9320	Maintenance of General Plant	0	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	-	-	-
155		Total A&G	18,072,504			11,819,037	5,787,264	466,203
156								
157		TOTAL O&M EXPENSE	120,959,622			21,877,272	10,395,048	88,687,302

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Intangible Plant:						
2								
3	30100	Organization	-	99.0	-	-	-	-
4	30200	Franchises & Consents	-	99.0	-	-	-	-
5	30300	Misc Intangible Plant	-	99.0	-	-	-	-
6								
7		Total Intangible Plant:	0			0	0	0
8								
9		Production Plant:						
10								
11	32520	Producing Leaseholds	-	99.0	-	-	-	-
12	32540	Rights of Ways	-	99.0	-	-	-	-
13	33100	Production Gas Wells Equipment	-	99.0	-	-	-	-
14	33201	Field Lines	-	99.0	-	-	-	-
15	33202	Tributary Lines	-	99.0	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	-	99.0	-	-	-	-
17	33600	Purification Equipment	-	99.0	-	-	-	-
18								
19		Total Production Plant	0			0	0	0
20								
21		Storage Plant:						
22								
23	35010	Land	-	3.5	Storage (50/50)	-	-	-
24	35020	Rights of Way	32	3.5	Storage (50/50)	-	16	16
25	35100	Structures and Improvements	294	3.5	Storage (50/50)	-	147	147
26	35102	Compression Station Equipment	3,062	3.5	Storage (50/50)	-	1,531	1,531
27	35103	Meas. & Reg. Sta. Structues	255	3.5	Storage (50/50)	-	127	127
28	35104	Other Structures	1,897	3.5	Storage (50/50)	-	948	948
29	35200	Wells \ Rights of Way	241,977	3.5	Storage (50/50)	-	120,988	120,988
30	35201	Well Construction	27,200	3.5	Storage (50/50)	-	13,600	13,600
31	35202	Well Equipment	9,210	3.5	Storage (50/50)	-	4,605	4,605
32	35203	Cushion Gas	23,728	3.5	Storage (50/50)	-	11,864	11,864
33	35210	Leaseholds	1,000	3.5	Storage (50/50)	-	500	500
34	35211	Storage Rights	557	3.5	Storage (50/50)	-	279	279
35	35301	Field Lines	2,209	3.5	Storage (50/50)	-	1,105	1,105
36	35302	Tributary Lines	2,637	3.5	Storage (50/50)	-	1,319	1,319
37	35400	Compressor Station Equipment	308,927	3.5	Storage (50/50)	-	154,463	154,463
38	35500	Meas & Reg. Equipment	5,107	3.5	Storage (50/50)	-	2,553	2,553
39	35600	Purification Equipment	33,187	3.5	Storage (50/50)	-	16,594	16,594
40								
41		Total Storage Plant	661,278			0	330,639	330,639
42								
43		Transmission:						
44								
45	36510	Land & Land Rights	-	2.0	Demand	-	-	-
46	36520	Rights of Way	7,376	2.0	Demand	-	7,376	-
47	36602	Structures & Improvements	4,496	2.0	Demand	-	4,496	-
48	36603	Other Structues	-	2.0	Demand	-	-	-
49	36700	Mains Cathodic Protection	1,478	2.0	Demand	-	1,478	-
50	36701	Mains - Steel	384,012	2.0	Demand	-	384,012	-
51	36703	Mains - Anodes	-	2.0	Demand	-	-	-
52	36900	Meas. & Reg. Equipment	35,793	2.0	Demand	-	35,793	-
53	36901	Meas. & Reg. Equipment	40,624	2.0	Demand	-	40,624	-
54								
55		Total Transmission Plant	473,778			0	473,778	0
56								
57		Distribution:						
58								
59	37400	Land & Land Rights	-	4.0	Mains (Minimum System)	-	-	-
60	37401	Land	-	4.0	Mains (Minimum System)	-	-	-
61	37402	Land Rights	54,464	4.0	Mains (Minimum System)	32,235	22,228	-
62	37403	Land Other	-	4.0	Mains (Minimum System)	-	-	-
63	37500	Structures & Improvements	4,841	4.0	Mains (Minimum System)	2,865	1,976	-
64	37501	Structures & Improvements T.B.	1,437	4.0	Mains (Minimum System)	851	587	-
65	37502	Land Rights	666	4.0	Mains (Minimum System)	394	272	-
66	37503	Improvements	58	4.0	Mains (Minimum System)	34	24	-
67	37600	Mains Cathodic Protection	159,292	4.0	Mains (Minimum System)	94,280	65,012	-
68	37601	Mains - Steel	3,554,207	4.0	Mains (Minimum System)	2,103,622	1,450,585	-
69	37602	Mains - Plastic	3,416,357	4.0	Mains (Minimum System)	2,022,033	1,394,324	-
70	37603	Mains - Anodes	200,720	4.0	Mains (Minimum System)	118,800	81,920	-
71	37604	Mains - Leak Clamps	339,494	4.0	Mains (Minimum System)	200,936	138,558	-
72	37800	Meas & Reg. Sta. Equip - General	573,607	4.0	Mains (Minimum System)	339,500	234,107	-
73	37900	Meas & Reg. Sta. Equip - City Gate	214,735	4.0	Mains (Minimum System)	127,095	87,640	-
74	37905	Meas & Reg. Sta. Equipment T.b.	37,287	4.0	Mains (Minimum System)	22,069	15,218	-
75	38000	Services	4,814,131	1.0	Customer	4,814,131	-	-
76	38100	Meters	2,722,922	1.0	Customer	2,722,922	-	-
77	38200	Meter Installaitons	2,026,363	1.0	Customer	2,026,363	-	-
78	38300	House Regulators	124,799	1.0	Customer	124,799	-	-
79	38400	House Reg. Installations	12,401	1.0	Customer	12,401	-	-
80	38500	Ind. Meas. & Reg. Sta. Equipment	97,340	1.0	Customer	97,340	-	-
81	38600	Other Prop. On Cust. Prem	-	99.0	-	-	-	-
82								
83		Total Distribution Plant	18,355,122			14,862,670	3,492,451	0
84								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
85		General:						
86								
87	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
88	39000	Structures & Improvements	225,186	5.4	P, S, T & D Plant	155,570	64,926	4,690
89	39001	Structures - Brick	4,207	5.4	P, S, T & D Plant	2,906	1,213	88
90	39002	Improvements	21,302	5.4	P, S, T & D Plant	14,717	6,142	444
91	39003	Air Conditioning Equipment	553	5.4	P, S, T & D Plant	382	159	12
92	39004	Improvement to leased Premises	-	5.4	P, S, T & D Plant	-	-	-
93	39009	Office Furniture & Equipment	90,847	5.4	P, S, T & D Plant	62,762	26,193	1,892
94	39100	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
95	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
96	39200	Transportation Equipment	2,511	5.4	P, S, T & D Plant	1,735	724	52
97	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
98	39202	Trailers	508	5.4	P, S, T & D Plant	351	147	11
99	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
100	39400	Tools, Shop & Garage Equipment	169,362	5.4	P, S, T & D Plant	117,004	48,831	3,527
101	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
102	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
103	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
104	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
105	39700	Communication Equipment	28,944	5.4	P, S, T & D Plant	19,996	8,345	603
106	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
107	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
108	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
109	39800	Miscellaneous Equipment	199,380	5.4	P, S, T & D Plant	137,742	57,486	4,152
110	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
111	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
112	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
113	39903	Other Tangible Property - Network - H/W	-	5.4	P, S, T & D Plant	-	-	-
114	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
115	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
116	39906	Other Tang. Property - PC Hardware	11,055	5.4	P, S, T & D Plant	7,638	3,188	230
117	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
118	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
119	39908	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
120	40600	Amortization of gas plant acquisition adjustments	49,305	5.4	P, S, T & D Plant	34,062	14,216	1,027
121								
122								
123		Total General Plant	803,161			554,865	231,569	16,727
124								
125		TOTAL DIRECT DEPRECIATION EXPENSE	20,293,339			15,417,535	4,528,437	347,366
126								
127		Kentucky Mid-States General Office:						
128								
129		Intangible Plant:						
130								
131	30100	Organization	-	5.4	P, S, T & D Plant	-	-	-
132	30200	Franchises & Consents	-	5.4	P, S, T & D Plant	-	-	-
133	30300	Misc Intangible Plant	-	5.4	P, S, T & D Plant	-	-	-
134								
135		Total Intangible Plant:	0			0	0	0
136								
137		General:						
138								
139	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
140	39001	Structures Frame	3,943	5.4	P, S, T & D Plant	2,724	1,137	82
141	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
142	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
143	39004	Air Conditioning Equipment	156	5.4	P, S, T & D Plant	108	45	3
144	39009	Improvement to leased Premises	-	5.4	P, S, T & D Plant	-	-	-
145	39100	Office Furniture & Equipment	865	5.4	P, S, T & D Plant	598	249	18
146	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
147	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
148	39200	Transportation Equipment	62	5.4	P, S, T & D Plant	43	18	1
149	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
150	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
151	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
152	39400	Tools, Shop & Garage Equipment	1,400	5.4	P, S, T & D Plant	967	404	29
153	39600	Power Operated Equipment	10	5.4	P, S, T & D Plant	7	3	0
154	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
155	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
156	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
157	39700	Communication Equipment	-	5.4	P, S, T & D Plant	-	-	-
158	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
159	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
160	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
161	39800	Miscellaneous Equipment	-	5.4	P, S, T & D Plant	-	-	-
162	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
163	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
164	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
165	39903	Other Tangible Property - Network - H/W	1,552	5.4	P, S, T & D Plant	1,072	448	32
166	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
167	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
168	39906	Other Tang. Property - PC Hardware	-	5.4	P, S, T & D Plant	-	-	-
169	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
170	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
171	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
172	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
173								
174								
175		Total General Plant	7,989			5,519	2,303	166

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
176								
177		Shared Services General Office:						
178								
179		General:						
180								
181	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
182	39000	Structures & Improvements	11,489	5.4	P, S, T & D Plant	7,937	3,313	239
183	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
184	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
185	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
186	39009	Improvement to leased Premises	28,706	5.4	P, S, T & D Plant	19,832	8,277	598
187	39100	Office Furniture & Equipment	24,600	5.4	P, S, T & D Plant	16,995	7,093	512
188	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
189	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
190	39200	Transportation Equipment	948	5.4	P, S, T & D Plant	655	273	20
191	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
192	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
193	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
194	39400	Tools, Shop & Garage Equipment	171	5.4	P, S, T & D Plant	118	49	4
195	39500	Laboratory Equipment	-	5.4	P, S, T & D Plant	-	-	-
196	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
197	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
198	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
199	39700	Communication Equipment	2,242	5.4	P, S, T & D Plant	1,549	646	47
200	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
201	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
202	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
203	39800	Miscellaneous Equipment	386	5.4	P, S, T & D Plant	267	111	8
204	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
205	39901	Other Tangible Property - Servers - H/W	336,969	5.4	P, S, T & D Plant	232,796	97,156	7,018
206	39902	Other Tangible Property - Servers - S/W	221,166	5.4	P, S, T & D Plant	152,793	63,767	4,606
207	39903	Other Tangible Property - Network - H/W	33,165	5.4	P, S, T & D Plant	22,912	9,562	691
208	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
209	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
210	39906	Other Tang. Property - PC Hardware	42,815	5.4	P, S, T & D Plant	29,579	12,345	892
211	39907	Other Tang. Property - PC Software	440	5.4	P, S, T & D Plant	304	127	9
212	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
213	39909	Other Tang. Property - Application Software	510,816	5.4	P, S, T & D Plant	352,898	147,279	10,639
214	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
215	ADJ	WTW Adjustment	(8,467)	5.4	P, S, T & D Plant	(5,849)	(2,441)	(176)
216								
217		Total General Plant	1,205,447			832,785	347,557	25,105
218								
219		Shared Services Customer Support:						
220								
221		General:						
222								
223	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
224	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
225	36602	Structures & Improvements	26,371	5.4	P, S, T & D Plant	18,219	7,603	549
226	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
227	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
228	39009	Improvement to leased Premises	7,572	5.4	P, S, T & D Plant	5,231	2,183	158
229	39100	Office Furniture & Equipment	11,237	5.4	P, S, T & D Plant	7,763	3,240	234
230	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
231	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
232	39200	Transportation Equipment	-	5.4	P, S, T & D Plant	-	-	-
233	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
234	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
235	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
236	39500	Laboratory Equipment	2,649	5.4	P, S, T & D Plant	1,830	764	55
237	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
238	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
239	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
240	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
241	39700	Communication Equipment	6,715	5.4	P, S, T & D Plant	4,639	1,936	140
242	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
243	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
244	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
245	39800	Miscellaneous Equipment	2,101	5.4	P, S, T & D Plant	1,451	606	44
246	39900	Other Tangible Property	1,186	5.4	P, S, T & D Plant	819	342	25
247	39901	Other Tangible Property - Servers - H/W	38,567	5.4	P, S, T & D Plant	26,644	11,120	803
248	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
249	39903	Other Tangible Property - Network - H/W	4,009	5.4	P, S, T & D Plant	2,770	1,156	83
250	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
251	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
252	39906	Other Tang. Property - PC Hardware	18,676	5.4	P, S, T & D Plant	12,902	5,385	389
253	39907	Other Tang. Property - PC Software	11	5.4	P, S, T & D Plant	8	3	0
254	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
255	39909	Other Tang. Property - Application Software	402,314	5.4	P, S, T & D Plant	277,939	115,996	8,379
256	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
257								
258								
259		Total General Plant	521,409			360,216	150,334	10,859
260								
261	NTB	To Match Schedule C-1	192.03	5.4	P, S, T & D Plant	133	55	4
262								
263		TOTAL DEPRECIATION EXPENSE	22,028,375			16,616,188	5,028,686	383,501

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

		Test Year	Classif.	Classif.	Customer	Demand	Commodity
		$	Factor	Basis	$	$	$
1	Taxes Other Than Income						
2							
3	Non Revenue Related:						
4	Payroll Related	375,952	9.1	Allocated O&M Expenses	67,996	32,309	275,647
5	Property Related	12,386,174	5.4	P, S, T & D Plant	8,557,007	3,571,206	257,961
6	DOT Transmission User Tax	232,790	9.1	Allocated O&M Expenses	42,103	20,006	170,681
7	Other	444,432	9.1	Allocated O&M Expenses	80,382	38,194	325,857
8	Total Non Revenue Related:	13,439,348			8,747,489	3,661,714	1,030,146
9							
10	Revenue Related:						
11	State Gross Receipts - Tax	0	99.0	-	-	-	-
12	Local Gross Receipts - Tax	0	99.0	-	-	-	-
13	Public Service Commission Assessment	291,875	3.0	Commodity	-	-	291,875
14	Total Revenue Related:	291,875			0	0	291,875
15							
16	Total Taxes, Other Than Income	13,731,224			8,747,489	3,661,714	1,322,021
17							
18							
19	Interest Expense	10,240,350	13.0	Rate Base	7,007,952	2,927,472	304,927
20							
21	Amortization of COS and Depreciation Reserves	(2,188,517)	18.0	Total Cost of Service at Equalized ROR	(909,307)	(373,489)	(905,722)
22							
23	Amortization of Excess ADIT	(189,998)	18.0	Total Cost of Service at Equalized ROR	(78,942)	(32,425)	(78,631)

Atmos Energy Corporation, Kentucky/Mid-States Division							
Class Cost of Service - Customer/Demand Study							
Forecasted Test Period: Twelve Months Ended March 31, 2026							
SUMMARY OF CLASSIFICATION							
1							
2							
3							
4		Test Year	Classif.	Classif.	Customer	Demand	Commodity
5		$	Factor	Basis	$	$	$
6							
7	Operating Revenues	187,822,013			68,526,047	27,976,995	91,318,971
8							
9	Operating Expenses:						
10							
11	Operating & Maintenance	120,959,622			21,877,272	10,395,048	88,687,302
12	Depreciation & Amortization	22,028,375			16,616,188	5,028,686	383,501
13	Taxes Other Than Income	13,731,224			8,747,489	3,661,714	1,322,021
14							
15	Total Operating Expenses	156,719,221			47,240,949	19,085,448	90,392,824
16							
17	Income Before Taxes	31,102,792			21,285,098	8,891,547	926,147
18							
19	Interest Expense	10,240,350			7,007,952	2,927,472	304,927
20							
21	Income Taxes:						
22							
23	State Income Taxes	1,043,122	5.00%		713,857	298,204	31,061
24	Federal Income Taxes	4,162,057	21.00%		2,848,291	1,189,833	123,934
25	Total Deferred Income Taxes	0			0	0	0
26	Amortization of ITC	0			0	0	0
27							
28	Total Income Taxes	5,205,179			3,562,148	1,488,037	154,995
29							
30	Net Income	25,897,613			17,722,950	7,403,510	771,153
31							
32	Total Rate Base	628,233,491			429,929,614	179,596,976	18,706,901
33							
34	Rate of Return	4.1223%			4.1223%	4.1223%	4.1223%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Intangible Plant:								
2										
3	30100	Organization	6.2	P, S, T & D Plant - Customer	5,755	4,845	881	1	17	10
4	30200	Franchises & Consents	6.2	P, S, T & D Plant - Customer	82,800	69,717	12,683	18	239	144
5	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
6										
7		Total Intangible Plant:			88,555	74,562	13,565	19	255	154
8										
9		Production Plant:								
10										
11	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
12	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
13	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
14	33201	Field Lines	99.0	-	0	-	-	-	-	-
15	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
17	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
18										
19		Total Production Plant			0	0	0	0	0	0
20										
21		Storage Plant:								
22										
23	35010	Land	99.0	-	0	-	-	-	-	-
24	35020	Rights of Way	99.0	-	0	-	-	-	-	-
25	35100	Structures and Improvements	99.0	-	0	-	-	-	-	-
26	35102	Compression Station Equipment	99.0	-	0	-	-	-	-	-
27	35103	Meas. & Reg. Sta. Structues	99.0	-	0	-	-	-	-	-
28	35104	Other Structures	99.0	-	0	-	-	-	-	-
29	35200	Wells \ Rights of Way	99.0	-	0	-	-	-	-	-
30	35201	Well Construction	99.0	-	0	-	-	-	-	-
31	35202	Well Equipment	99.0	-	0	-	-	-	-	-
32	35203	Cushion Gas	99.0	-	0	-	-	-	-	-
33	35210	Leaseholds	99.0	-	0	-	-	-	-	-
34	35211	Storage Rights	99.0	-	0	-	-	-	-	-
35	35301	Field Lines	99.0	-	0	-	-	-	-	-
36	35302	Tributary Lines	99.0	-	0	-	-	-	-	-
37	35400	Compressor Station Equipment	99.0	-	0	-	-	-	-	-
38	35500	Meas & Reg. Equipment	99.0	-	0	-	-	-	-	-
39	35600	Purification Equipment	99.0	-	0	-	-	-	-	-
40										
41		Total Storage Plant			0	0	0	0	0	0
42										
43		Transmission:								
44										
45	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
46	36520	Rights of Way	99.0	-	0	-	-	-	-	-
47	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
48	36603	Other Structues	99.0	-	0	-	-	-	-	-
49	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
50	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
51	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
52	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
53	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
54										
55		Total Transmission Plant			0	0	0	0	0	0
56										
57		Distribution:								
58										
59	37400	Land & Land Rights	2.0	Bills	363,026	322,243	40,386	18	237	143
60	37401	Land	2.0	Bills	253,699	225,198	28,224	12	166	100
61	37402	Land Rights	2.0	Bills	2,460,713	2,184,271	273,752	119	1,605	966
62	37403	Land Other	2.0	Bills	1,648	1,463	183	0	1	1
63	37500	Structures & Improvements	2.0	Bills	198,967	176,614	22,135	10	130	78
64	37501	Structures & Improvements T.B.	2.0	Bills	59,079	52,442	6,572	3	39	23
65	37502	Land Rights	2.0	Bills	27,382	24,306	3,046	1	18	11
66	37503	Improvements	2.0	Bills	2,370	2,104	264	0	2	1
67	37600	Mains Cathodic Protection	2.0	Bills	2,023,173	1,795,885	225,076	98	1,320	795
68	37601	Mains - Steel	2.0	Bills	136,457,527	121,127,562	15,180,741	6,605	89,022	53,596
69	37602	Mains - Plastic	2.0	Bills	131,193,087	116,454,542	14,595,079	6,350	85,588	51,528
70	37603	Mains - Anodes	2.0	Bills	2,130,495	1,891,150	237,015	103	1,390	837
71	37604	Mains - Leak Clamps	2.0	Bills	4,018,713	3,567,242	447,077	195	2,622	1,578
72	37800	Meas & Reg. Sta. Equip - General	2.0	Bills	15,148,834	13,446,978	1,685,290	733	9,883	5,950
73	37900	Meas & Reg. Sta. Equip - City Gate	2.0	Bills	5,748,674	5,102,854	639,533	278	3,750	2,258
74	37905	Meas & Reg. Sta. Equipment T.b.	2.0	Bills	1,017,003	902,751	113,140	49	663	399
75	38000	Services	2.0	Bills	193,916,542	172,131,494	21,572,990	9,386	126,507	76,164
76	38100	Meters	4.0	Meter Investment	55,920,540	38,934,861	15,880,938	48,900	659,055	396,787
77	38200	Meter Installaitons	4.0	Meter Investment	61,761,518	43,001,661	17,539,724	54,007	727,894	438,232
78	38300	House Regulators	4.0	Meter Investment	3,974,497	2,767,256	1,128,722	3,476	46,842	28,201
79	38400	House Reg. Installations	4.0	Meter Investment	378,094	263,249	107,375	331	4,456	2,683
80	38500	Ind. Meas. & Reg. Sta. Equipment	2.2	Non-Residential Bills	5,725,878	-	5,670,142	2,467	33,251	20,019
81	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
82										
83		Total Distribution Plant			622,781,459	524,376,125	95,397,405	133,142	1,794,438	1,080,350

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
84										
85		General:								
86										
87	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	837,103	704,833	128,227	179	2,412	1,452
88	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	6,395,188	5,384,688	979,612	1,367	18,427	11,094
89	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
90	39002	Structures-Brick	6.2	P, S, T & D Plant - Customer	119,597	100,699	18,320	26	345	207
91	39003	Improvements	6.2	P, S, T & D Plant - Customer	605,624	509,930	92,769	129	1,745	1,051
92	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	8,950	7,536	1,371	2	26	16
93	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	875,444	737,115	134,100	187	2,522	1,519
94	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	1,255,235	1,056,896	192,276	268	3,617	2,177
95	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
96	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
97	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	124,871	105,140	19,128	27	360	217
98	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
99	39202	Trailers	6.2	P, S, T & D Plant - Customer	25,277	21,283	3,872	5	73	44
100	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
101	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	4,935,014	4,155,235	755,943	1,055	14,219	8,561
102	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
103	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
104	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
105	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
106	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	299,787	252,417	45,921	64	864	520
107	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
108	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
109	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
110	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	2,060,750	1,735,132	315,665	441	5,938	3,575
111	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
112	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	14,802	12,463	2,267	3	43	26
113	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
114	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
115	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
116	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
117	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	366,608	308,681	56,157	78	1,056	636
118	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
119	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
120	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
121	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
122										
123		Total General Plant			17,924,249	15,092,049	2,745,629	3,832	51,646	31,094
124										
125		TOTAL DIRECT PLANT			640,794,263	539,542,736	98,156,599	136,993	1,846,339	1,111,597
126										
127		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
128										
129		Kentucky Mid-States General Office:								
130										
131		Intangible Plant:								
132										
133	30100	Organization	6.2	P, S, T & D Plant - Customer	63,972	53,864	9,799	14	184	111
134	30200	Franchises & Consents	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
135	30300	Misc Intangible Plant	6.2	P, S, T & D Plant - Customer	383,038	322,514	58,674	82	1,104	664
136										
137		Total Intangible Plant			447,010	376,378	68,473	96	1,288	775
138										
139		General:								
140										
141	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
142	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	61,911	52,128	9,483	13	178	107
143	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
144	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
145	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	5,311	4,472	814	1	15	9
146	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	13,406	11,288	2,054	3	39	23
147	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	9,296	7,827	1,424	2	27	16
148	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
149	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
150	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	1,419	1,195	217	0	4	2
151	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
152	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
153	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
154	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	38,053	32,040	5,829	8	110	66
155	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	3,272	2,755	501	1	9	6
156	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
157	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
158	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
159	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
160	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
161	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
162	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
163	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
164	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
165	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
166	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
167	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	9,758	8,216	1,495	2	28	17
168	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
169	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
170	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
171	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	15,025	12,651	2,301	3	43	26
172	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
173	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
174	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
175										
176		Total General Plant			157,450	132,572	24,118	34	454	273
177										
178		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
179										
180		Shared Services General Office:								
181										
182		General:								
183										
184	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
185	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
186	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	333,834	281,085	51,137	71	962	579
187	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
188	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
189	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	443,787	373,664	67,979	95	1,279	770
190	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	265,409	223,472	40,655	57	765	460
191	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
192	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
193	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	9,941	8,370	1,523	2	29	17
194	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
195	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
196	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
197	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	950	800	145	0	3	2
198	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
199	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
200	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
201	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
202	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	24,319	20,476	3,725	5	70	42
203	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
204	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
205	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
206	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	3,811	3,209	584	1	11	7
207	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
208	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	1,815,744	1,528,839	278,135	388	5,232	3,150
209	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	1,461,320	1,230,417	223,844	312	4,211	2,535
210	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	201,763	169,883	30,906	43	581	350
211	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
212	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
213	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	148,433	124,979	22,737	32	428	257
214	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	2,607	2,195	399	1	8	5
215	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	3,413,019	2,873,730	522,805	730	9,834	5,921
216	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	1,143,252	962,607	175,123	244	3,294	1,983
217	39931	Other Tang. Property - ALGN	6.2	P, S, T & D Plant - Customer	552,224	464,968	84,589	118	1,591	958
218										
219		Total General Plant			9,820,412	8,268,695	1,504,287	2,099	28,296	17,036
220										
221		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
222										
223		Shared Services Customer Support:								
224										
225		General:								
226										
227	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	145,928	122,870	22,353	31	420	253
228	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
229	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	765,429	644,484	117,248	164	2,205	1,328
230	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
231	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
232	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	118,088	99,429	18,089	25	340	205
233	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	121,879	102,621	18,669	26	351	211
234	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
235	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
236	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	1,546	1,301	237	0	4	3
237	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
238	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
239	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
240	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	14,687	12,366	2,250	3	42	25
241	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
242	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
243	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
244	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
245	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	73,167	61,606	11,208	16	211	127
246	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
247	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
248	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
249	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	20,616	17,359	3,158	4	59	36
250	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	5,689	4,790	871	1	16	10
251	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	210,458	177,203	32,238	45	606	365
252	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	67,962	57,223	10,410	15	196	118
253	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	24,555	20,675	3,761	5	71	43
254	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
255	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
256	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	64,737	54,508	9,916	14	187	112
257	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	68	57	10	0	0	0
258	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	4,007,298	3,374,107	613,836	857	11,546	6,952
259	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
260	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
261										
262		Total General Plant			5,642,105	4,750,599	864,255	1,206	16,257	9,787
263										
264		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
265										
266		TOTAL PLANT IN SERVICE - CUSTOMER			656,861,240	553,070,979	100,617,732	140,427	1,892,633	1,139,469
267										
268		TOTAL CWIP W/O AFUDC - CUSTOMER			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
269		Intangible Plant:								
270										
271	30100	Organization	6.4	P, S, T & D Plant - Demand	2,402	1,297	800	-	305	-
272	30200	Franchises & Consents	6.4	P, S, T & D Plant - Demand	34,556	18,659	11,515	-	4,382	-
273	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
274										
275		Total Intangible Plant:			36,958	19,955	12,315	0	4,687	0
276										
277		Production Plant:								
278										
279	32520	Producing Leaseholds	3.0	Peak Day	0	-	-	-	-	-
280	32540	Rights of Ways	3.0	Peak Day	0	-	-	-	-	-
281	33100	Production Gas Wells Equipment	3.0	Peak Day	0	-	-	-	-	-
282	33201	Field Lines	3.0	Peak Day	0	-	-	-	-	-
283	33202	Tributary Lines	3.0	Peak Day	0	-	-	-	-	-
284	33400	Field Meas. & Reg. Sta. Equip	3.0	Peak Day	0	-	-	-	-	-
285	33600	Purification Equipment	3.0	Peak Day	0	-	-	-	-	-
286										
287		Total Production Plant			0	0	0	0	0	0
288										
289		Storage Plant:								
290										
291	35010	Land	3.0	Peak Day	130,563	70,498	43,507	-	16,558	-
292	35020	Rights of Way	3.0	Peak Day	2,341	1,264	780	-	297	-
293	35100	Structures and Improvements	3.0	Peak Day	8,958	4,837	2,985	-	1,136	-
294	35102	Compression Station Equipment	3.0	Peak Day	111,754	60,342	37,240	-	14,172	-
295	35103	Meas. & Reg. Sta. Structues	3.0	Peak Day	11,569	6,247	3,855	-	1,467	-
296	35104	Other Structures	3.0	Peak Day	68,721	37,106	22,900	-	8,715	-
297	35200	Wells \ Rights of Way	3.0	Peak Day	6,267,306	3,384,052	2,088,445	-	794,808	-
298	35201	Well Construction	3.0	Peak Day	849,999	458,960	283,244	-	107,795	-
299	35202	Well Equipment	3.0	Peak Day	333,680	180,171	111,192	-	42,317	-
300	35203	Cushion Gas	3.0	Peak Day	847,416	457,565	282,383	-	107,468	-
301	35210	Leaseholds	3.0	Peak Day	89,265	48,199	29,746	-	11,320	-
302	35211	Storage Rights	3.0	Peak Day	27,307	14,745	9,100	-	3,463	-
303	35301	Field Lines	3.0	Peak Day	87,675	47,341	29,216	-	11,119	-
304	35302	Tributary Lines	3.0	Peak Day	104,659	56,511	34,876	-	13,273	-
305	35400	Compressor Station Equipment	3.0	Peak Day	9,032,953	4,877,372	3,010,038	-	1,145,543	-
306	35500	Meas & Reg. Equipment	3.0	Peak Day	136,542	73,726	45,500	-	17,316	-
307	35600	Purification Equipment	3.0	Peak Day	663,749	358,393	221,180	-	84,175	-
308										
309		Total Storage Plant			18,774,458	10,137,330	6,256,185	0	2,380,942	0
310										
311		Transmission:								
312										
313	36510	Land & Land Rights	3.0	Peak Day	26,970	14,563	8,987	-	3,420	-
314	36520	Rights of Way	3.0	Peak Day	867,772	468,556	289,166	-	110,049	-
315	36602	Structures & Improvements	3.0	Peak Day	397,833	214,811	132,569	-	50,452	-
316	36603	Other Structues	3.0	Peak Day	60,826	32,843	20,269	-	7,714	-
317	36700	Mains Cathodic Protection	3.0	Peak Day	47,233	25,504	15,739	-	5,990	-
318	36701	Mains - Steel	3.0	Peak Day	27,826,921	15,025,237	9,272,724	-	3,528,959	-
319	36703	Mains - Anodes	3.0	Peak Day	11,134	6,012	3,710	-	1,412	-
320	36900	Meas. & Reg. Equipment	3.0	Peak Day	1,999,587	1,079,684	666,320	-	253,584	-
321	36901	Meas. & Reg. Equipment	3.0	Peak Day	2,269,499	1,225,424	756,262	-	287,814	-
322										
323		Total Transmission Plant			33,507,777	18,092,634	11,165,748	0	4,249,395	0
324										
325		Distribution:								
326										
327	37400	Land & Land Rights	3.0	Peak Day	250,330	135,167	83,417	-	31,746	-
328	37401	Land	3.0	Peak Day	174,942	94,460	58,296	-	22,186	-
329	37402	Land Rights	3.0	Peak Day	1,696,823	916,205	565,430	-	215,188	-
330	37403	Land Other	3.0	Peak Day	1,136	613	379	-	144	-
331	37500	Structures & Improvements	3.0	Peak Day	137,201	74,082	45,719	-	17,400	-
332	37501	Structures & Improvements T.B.	3.0	Peak Day	40,739	21,997	13,575	-	5,166	-
333	37502	Land Rights	3.0	Peak Day	18,882	10,195	6,292	-	2,395	-
334	37503	Improvements	3.0	Peak Day	1,635	883	545	-	207	-
335	37600	Mains Cathodic Protection	3.0	Peak Day	1,395,110	753,294	464,890	-	176,925	-
336	37601	Mains - Steel	3.0	Peak Day	94,096,392	50,807,656	31,355,604	-	11,933,132	-
337	37602	Mains - Plastic	3.0	Peak Day	90,466,216	48,847,531	30,145,926	-	11,472,760	-
338	37603	Mains - Anodes	3.0	Peak Day	1,469,116	793,254	489,551	-	186,311	-
339	37604	Mains - Leak Clamps	3.0	Peak Day	2,771,166	1,496,300	923,432	-	351,434	-
340	37800	Meas & Reg. Sta. Equip - General	3.0	Peak Day	10,446,112	5,640,412	3,480,943	-	1,324,757	-
341	37900	Meas & Reg. Sta. Equip - City Gate	3.0	Peak Day	3,964,087	2,140,422	1,320,947	-	502,718	-
342	37905	Meas & Reg. Sta. Equipment T.b.	3.0	Peak Day	701,290	378,664	233,690	-	88,936	-
343	38000	Services	99.0	-	0	-	-	-	-	-
344	38100	Meters	99.0	-	0	-	-	-	-	-
345	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
346	38300	House Regulators	99.0	-	0	-	-	-	-	-
347	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
348	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
349	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
350										
351		Total Distribution Plant			207,631,176	112,111,135	69,188,635	0	26,331,406	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
352										
353		General:								
354										
355	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	349,359	188,638	116,416	-	44,305	-
356	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	2,668,986	1,441,128	889,382	-	338,476	-
357	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
358	39002	Structures-Brick	6.4	P, S, T & D Plant - Demand	49,913	26,951	16,632	-	6,330	-
359	39003	Improvements	6.4	P, S, T & D Plant - Demand	252,753	136,475	84,224	-	32,054	-
360	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	3,735	2,017	1,245	-	474	-
361	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	365,360	197,277	121,748	-	46,334	-
362	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	523,863	282,862	174,566	-	66,435	-
363	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
364	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
365	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	52,114	28,139	17,366	-	6,609	-
366	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
367	39202	Trailers	6.4	P, S, T & D Plant - Demand	10,549	5,696	3,515	-	1,338	-
368	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
369	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	2,059,593	1,112,084	686,315	-	261,194	-
370	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
371	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
372	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
373	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
374	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	125,114	67,556	41,691	-	15,867	-
375	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
376	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
377	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
378	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	860,039	464,381	286,590	-	109,069	-
379	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
380	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	6,177	3,335	2,058	-	783	-
381	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
382	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
383	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
384	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
385	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	153,001	82,614	50,984	-	19,403	-
386	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
387	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
388	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
389	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
390										
391		Total General Plant			7,480,558	4,039,152	2,492,735	0	948,671	0
392										
393		TOTAL DIRECT PLANT			267,430,926	144,400,206	89,115,619	0	33,915,101	0
394										
395		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
396										
397		Kentucky Mid-States General Office:								
398										
399		Intangible Plant:								
400										
401	30100	Organization	6.4	P, S, T & D Plant - Demand	26,698	14,416	8,897	-	3,386	-
402	30200	Franchises & Consents	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
403	30300	Misc Intangible Plant	6.4	P, S, T & D Plant - Demand	159,858	86,316	53,269	-	20,273	-
404										
405		Total Intangible Plant:			186,556	100,732	62,166	0	23,659	0
406										
407		General:								
408										
409	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
410	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	25,838	13,951	8,610	-	3,277	-
411	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
412	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
413	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	2,216	1,197	739	-	281	-
414	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	5,595	3,021	1,864	-	710	-
415	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	3,880	2,095	1,293	-	492	-
416	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
417	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
418	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	592	320	197	-	75	-
419	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
420	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
421	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
422	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	15,881	8,575	5,292	-	2,014	-
423	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	1,366	737	455	-	173	-
424	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
425	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
426	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
427	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
428	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
429	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
430	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
431	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
432	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
433	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
434	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
435	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	4,072	2,199	1,357	-	516	-
436	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
437	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
438	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
439	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	6,270	3,386	2,089	-	795	-
440	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
441	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
442	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
443										
444		Total General Plant			65,711	35,481	21,897	0	8,333	0
445										
446		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
447										
448		Shared Services General Office:								
449										
450		General:								
451										
452	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
453	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
454	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	139,323	75,228	46,427	-	17,669	-
455	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
456	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
457	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	185,211	100,005	61,718	-	23,488	-
458	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	110,767	59,809	36,911	-	14,047	-
459	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
460	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
461	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	4,149	2,240	1,382	-	526	-
462	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
463	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
464	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
465	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	396	214	132	-	50	-
466	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
467	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
468	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
469	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
470	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	10,149	5,480	3,382	-	1,287	-
471	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
472	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
473	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
474	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	1,590	859	530	-	202	-
475	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
476	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	757,788	409,170	252,517	-	96,101	-
477	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	609,871	329,302	203,227	-	77,343	-
478	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	84,205	45,467	28,059	-	10,679	-
479	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
480	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
481	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	61,947	33,449	20,643	-	7,856	-
482	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	1,088	588	363	-	138	-
483	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	1,424,399	769,109	474,650	-	180,640	-
484	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	477,128	257,627	158,993	-	60,508	-
485	39931	Other Tang. Property - ALGN	6.4	P, S, T & D Plant - Demand	230,467	124,441	76,798	-	29,227	-
486										
487		Total General Plant			4,098,479	2,212,987	1,365,730	0	519,762	0
488										
489		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
490										
491		Shared Services Customer Support:								
492										
493		General:								
494										
495	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	60,902	32,884	20,294	-	7,723	-
496	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
497	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	319,446	172,486	106,449	-	40,512	-
498	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
499	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
500	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	49,283	26,611	16,423	-	6,250	-
501	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	50,865	27,465	16,950	-	6,451	-
502	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
503	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
504	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	645	348	215	-	82	-
505	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
506	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
507	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
508	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	6,129	3,310	2,043	-	777	-
509	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
510	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
511	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
512	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
513	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	30,536	16,488	10,175	-	3,872	-
514	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
515	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
516	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
517	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	8,604	4,646	2,867	-	1,091	-
518	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	2,374	1,282	791	-	301	-
519	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	87,833	47,426	29,268	-	11,139	-
520	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	28,363	15,315	9,452	-	3,597	-
521	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	10,248	5,533	3,415	-	1,300	-
522	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
523	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
524	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	27,018	14,588	9,003	-	3,426	-
525	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	28	15	9	-	4	-
526	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	1,672,417	903,027	557,297	-	212,093	-
527	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
528	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
529										
530		Total General Plant			2,354,692	1,271,424	784,651	0	298,618	0
531										
532		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
533										
534		TOTAL PLANT IN SERVICE - DEMAND			274,136,365	148,020,830	91,350,062	0	34,765,472	0
535										
536		TOTAL CWIP W/O AFUDC - DEMAND			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
537		Intangible Plant:								
538										
539	30100	Organization	6.6	P, S, T & D Plant - Commodity	173	66	43	1	31	32
540	30200	Franchises & Consents	6.6	P, S, T & D Plant - Commodity	2,496	948	626	13	445	464
541	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
542										
543		Total Intangible Plant:			2,670	1,014	669	14	475	496
544										
545		Production Plant:								
546										
547	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
548	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
549	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
550	33201	Field Lines	99.0	-	0	-	-	-	-	-
551	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
552	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
553	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
554										
555		Total Production Plant			0	0	0	0	0	0
556										
557		Storage Plant:								
558										
559	35010	Land	1.5	Winter Volumes	130,563	49,601	32,736	705	23,252	24,269
560	35020	Rights of Way	1.5	Winter Volumes	2,341	889	587	13	417	435
561	35100	Structures and Improvements	1.5	Winter Volumes	8,958	3,403	2,246	48	1,595	1,665
562	35102	Compression Station Equipment	1.5	Winter Volumes	111,754	42,456	28,020	604	19,903	20,772
563	35103	Meas. & Reg. Sta. Structues	1.5	Winter Volumes	11,569	4,395	2,901	62	2,060	2,150
564	35104	Other Structures	1.5	Winter Volumes	68,721	26,107	17,230	371	12,239	12,774
565	35200	Wells \ Rights of Way	1.5	Winter Volumes	6,267,306	2,380,970	1,571,376	33,854	1,116,163	1,164,943
566	35201	Well Construction	1.5	Winter Volumes	849,999	322,918	213,117	4,591	151,379	157,995
567	35202	Well Equipment	1.5	Winter Volumes	333,680	126,766	83,662	1,802	59,426	62,023
568	35203	Cushion Gas	1.5	Winter Volumes	847,416	321,936	212,469	4,577	150,919	157,515
569	35210	Leaseholds	1.5	Winter Volumes	89,265	33,912	22,381	482	15,897	16,592
570	35211	Storage Rights	1.5	Winter Volumes	27,307	10,374	6,847	148	4,863	5,076
571	35301	Field Lines	1.5	Winter Volumes	87,675	33,308	21,982	474	15,614	16,297
572	35302	Tributary Lines	1.5	Winter Volumes	104,659	39,760	26,241	565	18,639	19,454
573	35400	Compressor Station Equipment	1.5	Winter Volumes	9,032,953	3,431,648	2,264,795	48,793	1,608,705	1,679,011
574	35500	Meas & Reg. Equipment	1.5	Winter Volumes	136,542	51,873	34,235	738	24,317	25,380
575	35600	Purification Equipment	1.5	Winter Volumes	663,749	252,160	166,419	3,585	118,209	123,375
576										
577		Total Storage Plant			18,774,458	7,132,478	4,707,243	101,414	3,343,599	3,489,724
578										
579		Transmission:								
580										
581	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
582	36520	Rights of Way	99.0	-	0	-	-	-	-	-
583	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
584	36603	Other Structues	99.0	-	0	-	-	-	-	-
585	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
586	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
587	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
588	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
589	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
590										
591		Total Transmission Plant			0	0	0	0	0	0
592										
593		Distribution:								
594										
595	37400	Land & Land Rights	1.0	Mcf	0	-	-	-	-	-
596	37401	Land	1.0	Mcf	0	-	-	-	-	-
597	37402	Land Rights	1.0	Mcf	0	-	-	-	-	-
598	37403	Land Other	1.0	Mcf	0	-	-	-	-	-
599	37500	Structures & Improvements	1.0	Mcf	0	-	-	-	-	-
600	37501	Structures & Improvements T.B.	1.0	Mcf	0	-	-	-	-	-
601	37502	Land Rights	1.0	Mcf	0	-	-	-	-	-
602	37503	Improvements	1.0	Mcf	0	-	-	-	-	-
603	37600	Mains Cathodic Protection	1.0	Mcf	0	-	-	-	-	-
604	37601	Mains - Steel	1.0	Mcf	0	-	-	-	-	-
605	37602	Mains - Plastic	1.0	Mcf	0	-	-	-	-	-
606	37603	Mains - Anodes	1.0	Mcf	0	-	-	-	-	-
607	37604	Mains - Leak Clamps	1.0	Mcf	0	-	-	-	-	-
608	37800	Meas & Reg. Sta. Equip - General	1.0	Mcf	0	-	-	-	-	-
609	37900	Meas & Reg. Sta. Equip - City Gate	1.0	Mcf	0	-	-	-	-	-
610	37905	Meas & Reg. Sta. Equipment T.b.	1.0	Mcf	0	-	-	-	-	-
611	38000	Services	99.0	-	0	-	-	-	-	-
612	38100	Meters	99.0	-	0	-	-	-	-	-
613	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
614	38300	House Regulators	99.0	-	0	-	-	-	-	-
615	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
616	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
617	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
618										
619		Total Distribution Plant			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
620										
621		General:								
622										
623	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	25,235	9,587	6,327	136	4,494	4,691
624	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	192,790	73,242	48,338	1,041	34,335	35,835
625	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
626	39002	Structures-Brick	6.6	P, S, T & D Plant - Commodity	3,605	1,370	904	19	642	670
627	39003	Improvements	6.6	P, S, T & D Plant - Commodity	18,257	6,936	4,578	99	3,251	3,394
628	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	270	102	68	1	48	50
629	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	26,391	10,026	6,617	143	4,700	4,906
630	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	37,840	14,376	9,488	204	6,739	7,034
631	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
632	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
633	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	3,764	1,430	944	20	670	700
634	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
635	39202	Trailers	6.6	P, S, T & D Plant - Commodity	762	289	191	4	136	142
636	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
637	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	148,772	56,519	37,301	804	26,495	27,653
638	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
639	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
640	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
641	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
642	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	9,037	3,433	2,266	49	1,609	1,680
643	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
644	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
645	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
646	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	62,124	23,601	15,576	336	11,064	11,547
647	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
648	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	446	170	112	2	79	83
649	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
650	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
651	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
652	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
653	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	11,052	4,199	2,771	60	1,968	2,054
654	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
655	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
656	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
657	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
658										
659		Total General Plant			540,347	205,280	135,479	2,919	96,232	100,438
660										
661		TOTAL DIRECT PLANT			19,317,475	7,338,772	4,843,391	104,347	3,440,306	3,590,658
662										
663		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
664										
665		Kentucky Mid-States General Office:								
666										
667		Intangible Plant:								
668										
669	30100	Organization	6.6	P, S, T & D Plant - Commodity	1,929	733	484	10	343	358
670	30200	Franchises & Consents	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
671	30300	Misc Intangible Plant	6.6	P, S, T & D Plant - Commodity	11,547	4,387	2,895	62	2,056	2,146
672										
673		Total Intangible Plant:			13,476	5,119	3,379	73	2,400	2,505
674										
675		General:								
676										
677	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
678	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	1,866	709	468	10	332	347
679	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
680	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
681	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	160	61	40	1	29	30
682	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	404	154	101	2	72	75
683	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	280	106	70	2	50	52
684	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
685	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
686	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	43	16	11	0	8	8
687	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
688	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
689	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
690	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	1,147	436	288	6	204	213
691	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	99	37	25	1	18	18
692	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
693	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
694	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
695	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
696	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
697	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
698	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
699	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
700	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
701	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
702	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
703	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	294	112	74	2	52	55
704	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
705	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
706	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
707	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	453	172	114	2	81	84
708	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
709	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
710	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
711										
712		Total General Plant			4,747	1,803	1,190	26	845	882
713										
714		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
715										
716		Shared Services General Office:								
717										
718		General:								
719										
720	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
721	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
722	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	10,064	3,823	2,523	54	1,792	1,871
723	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
724	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
725	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	13,378	5,083	3,354	72	2,383	2,487
726	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	8,001	3,040	2,006	43	1,425	1,487
727	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
728	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
729	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	300	114	75	2	53	56
730	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
731	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
732	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
733	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	29	11	7	0	5	5
734	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
735	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
736	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
737	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
738	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	733	279	184	4	131	136
739	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
740	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
741	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
742	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	115	44	29	1	20	21
743	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
744	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	54,738	20,795	13,724	296	9,748	10,174
745	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	44,053	16,736	11,045	238	7,846	8,188
746	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	6,082	2,311	1,525	33	1,083	1,131
747	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
748	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
749	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	4,475	1,700	1,122	24	797	832
750	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	79	30	20	0	14	15
751	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	102,889	39,088	25,797	556	18,324	19,125
752	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	34,465	13,093	8,641	186	6,138	6,406
753	39931	Other Tang. Property - ALGN	6.6	P, S, T & D Plant - Commodity	16,647	6,324	4,174	90	2,965	3,094
754										
755		Total General Plant			296,048	112,469	74,227	1,599	52,724	55,028
756										
757		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
758										
759		Shared Services Customer Support:								
760										
761		General:								
762										
763	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	4,399	1,671	1,103	24	783	818
764	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
765	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	23,075	8,766	5,785	125	4,109	4,289
766	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
767	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
768	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	3,560	1,352	893	19	634	662
769	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	3,674	1,396	921	20	654	683
770	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
771	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
772	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	47	18	12	0	8	9
773	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
774	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
775	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
776	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	443	168	111	2	79	82
777	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
778	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
779	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
780	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
781	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	2,206	838	553	12	393	410
782	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
783	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
784	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
785	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	621	236	156	3	111	116
786	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	171	65	43	1	31	32
787	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	6,344	2,410	1,591	34	1,130	1,179
788	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	2,049	778	514	11	365	381
789	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	740	281	186	4	132	138
790	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
791	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
792	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	1,952	741	489	11	348	363
793	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	2	1	1	0	0	0
794	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	120,805	45,894	30,289	653	21,514	22,455
795	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
796	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
797										
798		Total General Plant			170,088	64,617	42,645	919	30,291	31,615
799										
800		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
801										
802		TOTAL PLANT IN SERVICE - COMMODITY			19,801,832	7,522,781	4,964,832	106,964	3,526,567	3,680,688
803										
804		TOTAL CWIP W/O AFUDC - COMMODITY			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Total Plant in Service

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
805		Intangible Plant:								
806										
807	30100	Organization			8,330	6,208	1,725	2	352	42
808	30200	Franchises & Consents			119,853	89,324	24,824	31	5,065	608
809	30300	Misc Intangible Plant			0	-	-	-	-	-
810										
811		Total Intangible Plant:			128,182	95,532	26,550	33	5,418	650
812										
813		Production Plant:								
814										
815	32520	Producing Leaseholds			0	-	-	-	-	-
816	32540	Rights of Ways			0	-	-	-	-	-
817	33100	Production Gas Wells Equipment			0	-	-	-	-	-
818	33201	Field Lines			0	-	-	-	-	-
819	33202	Tributary Lines			0	-	-	-	-	-
820	33400	Field Meas. & Reg. Sta. Equip			0	-	-	-	-	-
821	33600	Purification Equipment			0	-	-	-	-	-
822										
823		Total Production Plant			0	0	0	0	0	0
824										
825		Storage Plant:								
826										
827	35010	Land			261,127	120,100	76,243	705	39,810	24,269
828	35020	Rights of Way			4,682	2,153	1,367	13	714	435
829	35100	Structures and Improvements			17,916	8,240	5,231	48	2,731	1,665
830	35102	Compression Station Equipment			223,508	102,798	65,259	604	34,075	20,772
831	35103	Meas. & Reg. Sta. Structues			23,138	10,642	6,756	62	3,528	2,150
832	35104	Other Structures			137,443	63,214	40,130	371	20,954	12,774
833	35200	Wells \ Rights of Way			12,534,611	5,765,022	3,659,821	33,854	1,910,971	1,164,943
834	35201	Well Construction			1,699,999	781,877	496,361	4,591	259,174	157,995
835	35202	Well Equipment			667,359	306,937	194,854	1,802	101,743	62,023
836	35203	Cushion Gas			1,694,833	779,502	494,853	4,577	258,387	157,515
837	35210	Leaseholds			178,530	82,111	52,127	482	27,218	16,592
838	35211	Storage Rights			54,614	25,119	15,946	148	8,326	5,076
839	35301	Field Lines			175,350	80,649	51,198	474	26,733	16,297
840	35302	Tributary Lines			209,319	96,272	61,116	565	31,912	19,454
841	35400	Compressor Station Equipment			18,065,905	8,309,021	5,274,833	48,793	2,754,248	1,679,011
842	35500	Meas & Reg. Equipment			273,084	125,599	79,734	738	41,633	25,380
843	35600	Purification Equipment			1,327,498	610,554	387,599	3,585	202,384	123,375
844										
845		Total Storage Plant			37,548,916	17,269,809	10,963,428	101,414	5,724,541	3,489,724
846										
847		Transmission:								
848										
849	36510	Land & Land Rights			26,970	14,563	8,987	-	3,420	-
850	36520	Rights of Way			867,772	468,556	289,166	-	110,049	-
851	36602	Structures & Improvements			397,833	214,811	132,569	-	50,452	-
852	36603	Other Structues			60,826	32,843	20,269	-	7,714	-
853	36700	Mains Cathodic Protection			47,233	25,504	15,739	-	5,990	-
854	36701	Mains - Steel			27,826,921	15,025,237	9,272,724	-	3,528,959	-
855	36703	Mains - Anodes			11,134	6,012	3,710	-	1,412	-
856	36900	Meas. & Reg. Equipment			1,999,587	1,079,684	666,320	-	253,584	-
857	36901	Meas. & Reg. Equipment			2,269,499	1,225,424	756,262	-	287,814	-
858										
859		Total Transmission Plant			33,507,777	18,092,634	11,165,748	0	4,249,395	0
860										
861		Distribution:								
862										
863	37400	Land & Land Rights			613,356	457,409	123,803	18	31,983	143
864	37401	Land			428,640	319,658	86,519	12	22,351	100
865	37402	Land Rights			4,157,536	3,100,476	839,181	119	216,793	966
866	37403	Land Other			2,784	2,076	562	0	145	1
867	37500	Structures & Improvements			336,168	250,696	67,854	10	17,529	78
868	37501	Structures & Improvements T.B.			99,818	74,439	20,148	3	5,205	23
869	37502	Land Rights			46,264	34,501	9,338	1	2,412	11
870	37503	Improvements			4,005	2,987	808	0	209	1
871	37600	Mains Cathodic Protection			3,418,283	2,549,179	689,966	98	178,245	795
872	37601	Mains - Steel			230,553,919	171,935,218	46,536,345	6,605	12,022,155	53,596
873	37602	Mains - Plastic			221,659,304	165,302,073	44,741,004	6,350	11,558,348	51,528
874	37603	Mains - Anodes			3,599,610	2,684,404	726,566	103	187,700	837
875	37604	Mains - Leak Clamps			6,789,879	5,063,542	1,370,509	195	354,056	1,578
876	37800	Meas & Reg. Sta. Equip - General			25,594,946	19,087,390	5,166,233	733	1,334,640	5,950
877	37900	Meas & Reg. Sta. Equip - City Gate			9,712,761	7,243,276	1,960,480	278	506,469	2,258
878	37905	Meas & Reg. Sta. Equipment T.b.			1,718,293	1,281,415	346,830	49	89,600	399
879	38000	Services			193,916,542	172,131,494	21,572,990	9,386	126,507	76,164
880	38100	Meters			55,920,540	38,934,861	15,880,938	48,900	659,055	396,787
881	38200	Meter Installaitons			61,761,518	43,001,661	17,539,724	54,007	727,894	438,232
882	38300	House Regulators			3,974,497	2,767,256	1,128,722	3,476	46,842	28,201
883	38400	House Reg. Installations			378,094	263,249	107,375	331	4,456	2,683
884	38500	Ind. Meas. & Reg. Sta. Equipment			5,725,878	-	5,670,142	2,467	33,251	20,019
885	38600	Other Prop. On Cust. Prem			0	-	-	-	-	-
886										
887		Total Distribution Plant			830,412,635	636,487,260	164,586,040	133,142	28,125,844	1,080,350

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
888										
889		General:								
890										
891	38900	Land & Land Rights			1,211,697	903,057	250,971	315	51,211	6,143
892	39000	Structures & Improvements			9,256,964	6,899,058	1,917,332	2,409	391,237	46,929
893	39001	Structures Frame			0	-	-	-	-	-
894	39002	Structures-Brick			173,115	129,020	35,856	45	7,317	878
895	39003	Improvements			876,634	653,341	181,571	228	37,050	4,444
896	39004	Air Conditioning Equipment			12,955	9,655	2,683	3	548	66
897	39009	Improvement to leased Premises			1,267,195	944,419	262,466	330	53,557	6,424
898	39100	Office Furniture & Equipment			1,816,939	1,354,133	376,330	473	76,791	9,211
899	39102	Remittance Processing Equip			0	-	-	-	-	-
900	39103	Office Machines			0	-	-	-	-	-
901	39200	Transportation Equipment			180,749	134,709	37,437	47	7,639	916
902	39201	Trucks			0	-	-	-	-	-
903	39202	Trailers			36,588	27,269	7,578	10	1,546	185
904	39300	Stores Equipment			0	-	-	-	-	-
905	39400	Tools, Shop & Garage Equipment			7,143,379	5,323,838	1,479,559	1,859	301,908	36,214
906	39600	Power Operated Equipment			0	-	-	-	-	-
907	39603	Ditchers			0	-	-	-	-	-
908	39604	Backhoes			0	-	-	-	-	-
909	39605	Welders			0	-	-	-	-	-
910	39700	Communication Equipment			433,938	323,406	89,879	113	18,340	2,200
911	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
912	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
913	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
914	39800	Miscellaneous Equipment			2,982,913	2,223,114	617,830	776	126,070	15,122
915	39900	Other Tangible Property			0	-	-	-	-	-
916	39901	Other Tangible Property - Servers - H/W			21,425	15,968	4,438	6	906	109
917	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
918	39903	Other Tangible Property - Network - H/W			0	-	-	-	-	-
919	39904	Other Tang. Property - CPU			0	-	-	-	-	-
920	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
921	39906	Other Tang. Property - PC Hardware			530,662	395,493	109,912	138	22,428	2,690
922	39907	Other Tang. Property - PC Software			0	-	-	-	-	-
923	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
924	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
925	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
926										
927		Total General Plant			25,945,153	19,336,480	5,373,843	6,751	1,096,548	131,531
928										
929		TOTAL DIRECT PLANT			927,542,664	691,281,714	192,115,608	241,340	39,201,746	4,702,255
930										
931		CWIP w/o AFUDC			0	-	-	-	-	-
932										
933		Kentucky Mid-States General Office:								
934										
935		Intangible Plant:								
936										
937	30100	Organization			92,599	69,012	19,179	24	3,914	469
938	30200	Franchises & Consents			0	-	-	-	-	-
939	30300	Misc Intangible Plant			554,443	413,217	114,838	144	23,433	2,811
940										
941		Total Intangible Plant:			647,042	482,229	134,017	168	27,347	3,280
942										
943		General:								
944										
945	37400	Land & Land Rights			0	-	-	-	-	-
946	39001	Structures Frame			89,615	66,789	18,561	23	3,788	454
947	36602	Structures & Improvements			0	-	-	-	-	-
948	38900	Land & Land Rights			0	-	-	-	-	-
949	39004	Air Conditioning Equipment			7,687	5,729	1,592	2	325	39
950	39009	Improvement to leased Premises			19,405	14,462	4,019	5	820	98
951	39100	Office Furniture & Equipment			13,456	10,028	2,787	4	569	68
952	39102	Remittance Processing Equip			0	-	-	-	-	-
953	39103	Office Machines			0	-	-	-	-	-
954	39200	Transportation Equipment			2,054	1,531	425	1	87	10
955	39201	Trucks			0	-	-	-	-	-
956	39202	Trailers			0	-	-	-	-	-
957	39300	Stores Equipment			0	-	-	-	-	-
958	39400	Tools, Shop & Garage Equipment			55,081	41,051	11,408	14	2,328	279
959	39600	Power Operated Equipment			4,736	3,530	981	1	200	24
960	39603	Ditchers			0	-	-	-	-	-
961	39604	Backhoes			0	-	-	-	-	-
962	39605	Welders			0	-	-	-	-	-
963	39700	Communication Equipment			0	-	-	-	-	-
964	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
965	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
966	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
967	39800	Miscellaneous Equipment			0	-	-	-	-	-
968	39900	Other Tangible Property			0	-	-	-	-	-
969	39901	Other Tangible Property - Servers - H/W			0	-	-	-	-	-
970	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
971	39903	Other Tangible Property - Network - H/W			14,125	10,527	2,926	4	597	72
972	39904	Other Tang. Property - CPU			0	-	-	-	-	-
973	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
974	39906	Other Tang. Property - PC Hardware			0	-	-	-	-	-
975	39907	Other Tang. Property - PC Software			21,748	16,208	4,504	6	919	110
976	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
977	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
978	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
979										
980		Total General Plant			227,907	169,855	47,205	59	9,632	1,155
981										
982		CWIP w/o AFUDC			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
983										
984		Shared Services General Office:								
985										
986		General:								
987										
988	37400	Land & Land Rights			0	-	-	-	-	-
989	39001	Structures Frame			0	-	-	-	-	-
990	36602	Structures & Improvements			483,221	360,137	100,086	126	20,423	2,450
991	37503	Improvements			0	-	-	-	-	-
992	39004	Air Conditioning Equipment			0	-	-	-	-	-
993	39009	Improvement to leased Premises			642,376	478,752	133,051	167	27,149	3,257
994	39100	Office Furniture & Equipment			384,176	286,320	79,572	100	16,237	1,948
995	39102	Remittance Processing Equip			0	-	-	-	-	-
996	39103	Office Machines			0	-	-	-	-	-
997	39200	Transportation Equipment			14,389	10,724	2,980	4	608	73
998	39201	Trucks			0	-	-	-	-	-
999	39202	Trailers			0	-	-	-	-	-
1000	39300	Stores Equipment			0	-	-	-	-	-
1001	39400	Tools, Shop & Garage Equipment			1,375	1,025	285	0	58	7
1002	39600	Power Operated Equipment			0	-	-	-	-	-
1003	39603	Ditchers			0	-	-	-	-	-
1004	39604	Backhoes			0	-	-	-	-	-
1005	39605	Welders			0	-	-	-	-	-
1006	39700	Communication Equipment			35,202	26,235	7,291	9	1,488	178
1007	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
1008	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
1009	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
1010	39800	Miscellaneous Equipment			5,516	4,111	1,142	1	233	28
1011	39900	Other Tangible Property			0	-	-	-	-	-
1012	39901	Other Tangible Property - Servers - H/W			2,628,270	1,958,805	544,376	684	111,081	13,324
1013	39902	Other Tangible Property - Servers - S/W			2,115,244	1,576,455	438,116	550	89,399	10,723
1014	39903	Other Tangible Property - Network - H/W			292,050	217,660	60,490	76	12,343	1,481
1015	39904	Other Tang. Property - CPU			0	-	-	-	-	-
1016	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
1017	39906	Other Tang. Property - PC Hardware			214,855	160,128	44,501	56	9,081	1,089
1018	39907	Other Tang. Property - PC Software			3,774	2,813	782	1	160	19
1019	39908	Other Tang. Property - Mainframe S/W			4,940,307	3,681,927	1,023,252	1,285	208,798	25,045
1020	39909	Other Tang. Property - Application Software			1,654,844	1,233,327	342,757	431	69,940	8,389
1021	39931	Other Tang. Property - ALGN			799,338	595,733	165,562	208	33,783	4,052
1022										
1023		Total General Plant			14,214,939	10,594,151	2,944,244	3,699	600,781	72,064
1024										
1025		CWIP w/o AFUDC			0	-	-	-	-	-
1026										
1027		Shared Services Customer Support:								
1028										
1029		General:								
1030										
1031	37400	Land & Land Rights			211,229	157,425	43,750	55	8,927	1,071
1032	39001	Structures Frame			0	-	-	-	-	-
1033	36602	Structures & Improvements			1,107,950	825,737	229,482	288	46,827	5,617
1034	37503	Improvements			0	-	-	-	-	-
1035	39004	Air Conditioning Equipment			0	-	-	-	-	-
1036	39009	Improvement to leased Premises			170,931	127,392	35,404	44	7,224	867
1037	39100	Office Furniture & Equipment			176,418	131,481	36,540	46	7,456	894
1038	39102	Remittance Processing Equip			0	-	-	-	-	-
1039	39103	Office Machines			0	-	-	-	-	-
1040	39200	Transportation Equipment			2,237	1,667	463	1	95	11
1041	39201	Trucks			0	-	-	-	-	-
1042	39202	Trailers			0	-	-	-	-	-
1043	39300	Stores Equipment			0	-	-	-	-	-
1044	39400	Tools, Shop & Garage Equipment			21,259	15,844	4,403	6	898	108
1045	39600	Power Operated Equipment			0	-	-	-	-	-
1046	39603	Ditchers			0	-	-	-	-	-
1047	39604	Backhoes			0	-	-	-	-	-
1048	39605	Welders			0	-	-	-	-	-
1049	39700	Communication Equipment			105,908	78,932	21,936	28	4,476	537
1050	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
1051	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
1052	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
1053	39800	Miscellaneous Equipment			29,842	22,240	6,181	8	1,261	151
1054	39900	Other Tangible Property			8,234	6,137	1,705	2	348	42
1055	39901	Other Tangible Property - Servers - H/W			304,635	227,039	63,097	79	12,875	1,544
1056	39902	Other Tangible Property - Servers - S/W			98,374	73,317	20,376	26	4,158	499
1057	39903	Other Tangible Property - Network - H/W			35,543	26,489	7,362	9	1,502	180
1058	39904	Other Tang. Property - CPU			0	-	-	-	-	-
1059	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
1060	39906	Other Tang. Property - PC Hardware			93,706	69,838	19,409	24	3,960	475
1061	39907	Other Tang. Property - PC Software			98	73	20	0	4	0
1062	39908	Other Tang. Property - Mainframe S/W			5,800,519	4,323,028	1,201,422	1,509	245,154	29,406
1063	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
1064	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
1065										
1066		Total General Plant			8,166,885	6,086,640	1,691,551	2,125	345,166	41,403
1067										
1068		CWIP w/o AFUDC			0	-	-	-	-	-
1069										
1070		TOTAL PLANT IN SERVICE			950,799,437	708,614,590	196,932,626	247,391	40,184,673	4,820,157
1071										
1072		TOTAL CWIP W/O AFUDC			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Intangible Plant:								
2										
3	30100	Organization	6.2	P, S, T & D Plant - Customer	5,755	4,845	881	1	17	10
4	30200	Franchises & Consents	6.2	P, S, T & D Plant - Customer	82,800	69,717	12,683	18	239	144
5	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
6										
7		Total Intangible Plant:			88,555	74,562	13,565	19	255	154
8										
9		Production Plant:								
10										
11	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
12	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
13	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
14	33201	Field Lines	99.0	-	0	-	-	-	-	-
15	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
17	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
18										
19		Total Production Plant			0	0	0	0	0	0
20										
21		Storage Plant:								
22										
23	35010	Land	99.0	-	0	-	-	-	-	-
24	35020	Rights of Way	99.0	-	0	-	-	-	-	-
25	35100	Structures and Improvements	99.0	-	0	-	-	-	-	-
26	35102	Compression Station Equipment	99.0	-	0	-	-	-	-	-
27	35103	Meas. & Reg. Sta. Structues	99.0	-	0	-	-	-	-	-
28	35104	Other Structures	99.0	-	0	-	-	-	-	-
29	35200	Wells \ Rights of Way	99.0	-	0	-	-	-	-	-
30	35201	Well Construction	99.0	-	0	-	-	-	-	-
31	35202	Well Equipment	99.0	-	0	-	-	-	-	-
32	35203	Cushion Gas	99.0	-	0	-	-	-	-	-
33	35210	Leaseholds	99.0	-	0	-	-	-	-	-
34	35211	Storage Rights	99.0	-	0	-	-	-	-	-
35	35301	Field Lines	99.0	-	0	-	-	-	-	-
36	35302	Tributary Lines	99.0	-	0	-	-	-	-	-
37	35400	Compressor Station Equipment	99.0	-	0	-	-	-	-	-
38	35500	Meas & Reg. Equipment	99.0	-	0	-	-	-	-	-
39	35600	Purification Equipment	99.0	-	0	-	-	-	-	-
40										
41		Total Storage Plant			0	-	-	-	-	-
42										
43		Transmission:								
44										
45	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
46	36520	Rights of Way	99.0	-	0	-	-	-	-	-
47	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
48	36603	Other Structues	99.0	-	0	-	-	-	-	-
49	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
50	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
51	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
52	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
53	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
54										
55		Total Transmission Plant			0	-	-	-	-	-
56										
57		Distribution:								
58										
59	37400	Land & Land Rights	2.0	Bills	0	-	-	-	-	-
60	37401	Land	2.0	Bills	0	-	-	-	-	-
61	37402	Land Rights	2.0	Bills	381,258	338,427	42,415	18	249	150
62	37403	Land Other	2.0	Bills	0	-	-	-	-	-
63	37500	Structures & Improvements	2.0	Bills	80,716	71,648	8,980	4	53	32
64	37501	Structures & Improvements T.B.	2.0	Bills	48,397	42,960	5,384	2	32	19
65	37502	Land Rights	2.0	Bills	24,096	21,389	2,681	1	16	9
66	37503	Improvements	2.0	Bills	1,305	1,158	145	0	1	1
67	37600	Mains Cathodic Protection	2.0	Bills	1,060,826	941,650	118,016	51	692	417
68	37601	Mains - Steel	2.0	Bills	18,318,878	16,260,891	2,037,954	887	11,951	7,195
69	37602	Mains - Plastic	2.0	Bills	16,603,246	14,737,998	1,847,092	804	10,832	6,521
70	37603	Mains - Anodes	2.0	Bills	1,095,644	972,556	121,889	53	715	430
71	37604	Mains - Leak Clamps	2.0	Bills	3,323,389	2,950,031	369,723	161	2,168	1,305
72	37800	Meas & Reg. Sta. Equip - General	2.0	Bills	3,129,903	2,778,283	348,198	152	2,042	1,229
73	37900	Meas & Reg. Sta. Equip - City Gate	2.0	Bills	862,145	765,290	95,913	42	562	339
74	37905	Meas & Reg. Sta. Equipment T.b.	2.0	Bills	632,327	561,290	70,346	31	413	248
75	38000	Services	2.0	Bills	38,828,841	34,466,716	4,319,663	1,879	25,331	15,251
76	38100	Meters	4.0	Meter Investment	23,998,006	16,708,691	6,815,221	20,985	282,830	170,279
77	38200	Meter Installaitons	4.0	Meter Investment	22,719,274	15,818,369	6,452,072	19,867	267,759	161,206
78	38300	House Regulators	4.0	Meter Investment	469,350	326,786	133,291	410	5,532	3,330
79	38400	House Reg. Installations	4.0	Meter Investment	130,024	90,530	36,926	114	1,532	923
80	38500	Ind. Meas. & Reg. Sta. Equipment	2.2	Non-Residential Bills	3,090,645	-	3,060,560	1,332	17,948	10,805
81	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
82										
83		Total Distribution Plant			134,798,268	107,854,663	25,886,468	46,793	630,656	379,689

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Customer/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
84											
85		General:									
86											
87	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
88	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	1,359,916	1,145,036	208,311	291	3,918	2,359	
89	39002	Structures - Brick	6.2	P, S, T & D Plant - Customer	82,085	69,114	12,574	18	237	142	
90	39003	Improvements	6.2	P, S, T & D Plant - Customer	231,487	194,910	35,459	49	667	402	
91	39003	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	6,159	5,186	943	1	18	11	
92	39004	Improvement to Leased Premises	6.2	P, S, T & D Plant - Customer	875,444	737,115	134,100	187	2,522	1,519	
93	39009	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	1,018,112	857,241	155,954	218	2,934	1,766	
94	39100	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
95	Composite	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
96	39103	Transportation Equipment	6.2	P, S, T & D Plant - Customer	52,378	44,102	8,023	11	151	91	
97	39200	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
98	39201	Trailers	6.2	P, S, T & D Plant - Customer	5,981	5,036	916	1	17	10	
99	39202	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
100	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	2,311,410	1,946,185	354,061	494	6,660	4,010	
101	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
102	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
103	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
104	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
105	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	253,303	213,279	38,801	54	730	439	
106	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
107	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
108	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
109	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	1,070,093	901,008	163,916	229	3,083	1,856	
110	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
111	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	14,919	12,562	2,285	3	43	26	
112	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
113	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
114	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
115	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
116	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	366,154	308,298	56,087	78	1,055	635	
117	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
118	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
119	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
120		Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
121		Retirement Work in Progress	6.2	P, S, T & D Plant - Customer	(1,143,760)	(963,036)	(175,201)	(245)	(3,296)	(1,984)	
122		AR 15 general plant amortization	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
123											
124		Total General Plant			6,503,680	5,476,037	996,231	1,390	18,739	11,282	
125											
126		TOTAL DIRECT RESERVE FOR DEPRECIATION			141,390,503	113,405,262	26,896,264	48,202	649,650	391,125	
127											
128		Kentucky Mid-States General Office:									
129											
130		Intangible Plant:									
131											
132	30100	Organization	99.0	-	0	-	-	-	-	-	
133	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
134	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
135											
136		Total Intangible Plant:									
137											
138		General:									
139											
140	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
141	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	41,473	34,920	6,353	9	119	72	
142	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
143	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
144	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	5,296	4,459	811	1	15	9	
145	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	13,406	11,288	2,054	3	39	23	
146	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	2,943	2,478	451	1	8	5	
147	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
148	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
149	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	(684)	(576)	(105)	(0)	(2)	(1)	
150	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
151	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
152	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
153	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	18,594	15,656	2,848	4	54	32	
154	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	1,034	870	158	0	3	2	
155	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
156	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
157	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
158	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	(7,618)	(6,414)	(1,167)	(2)	(22)	(13)	
159	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
160	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
161	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
162	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	(43,841)	(36,914)	(6,716)	(9)	(126)	(76)	
163	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
164	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
165	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
166	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	6,743	5,677	1,033	1	19	12	
167	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
168	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
169	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
170	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	15,025	12,651	2,301	3	43	26	
171	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
172	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
173	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
174		Retirement Work in Progress	6.2	P, S, T & D Plant - Customer	18,130	15,265	2,777	4	52	31	
175											
176		Total General Plant			70,501	59,361	10,799	15	203	122	

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF RESERVE FOR DEPRECIATION										
177										
178		Shared Services General Office:								
179										
180		General:								
181										
182	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
183	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	109,388	92,103	16,756	23	315	190
184	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
185	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
186	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
187	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	342,976	288,783	52,537	73	988	595
188	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	133,359	112,287	20,428	29	384	231
189	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	0	0	0	0	0
190	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	0	0	0	0	0
191	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	7,180	6,045	1,100	2	21	12
192	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
193	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
194	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
195	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	875	737	134	0	3	2
196	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
197	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
198	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
199	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
200	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	5,322	4,481	815	1	15	9
201	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
202	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
203	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
204	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	1,748	1,472	268	0	5	3
205	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	(0)	(0)	(0)	(0)	(0)	(0)
206	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	411,258	346,276	62,996	88	1,185	713
207	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	485,869	409,097	74,425	104	1,400	843
208	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	66,139	55,689	10,131	14	191	115
209	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
210	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
211	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	59,990	50,511	9,189	13	173	104
212	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	2,196	1,849	336	0	6	4
213	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
214	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	3,408,445	2,869,878	522,104	729	9,821	5,913
215	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
216	ADJ	WTW Adjustment	6.2	P, S, T & D Plant - Customer	6,337	5,336	971	1	18	11
217										
218		Total General Plant			5,041,083	4,244,544	772,191	1,078	14,525	8,745
219					1,679,647	1,414,247	257,288	359	4,840	2,914
220		Shared Services Customer Support:								
221										
222		General:								
223										
224	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
225	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
226	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	290,685	244,754	44,527	62	838	504
227	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
228	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
229	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	94,586	79,641	14,489	20	273	164
230	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	68,423	57,612	10,481	15	197	119
231	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
232	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
233	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	1,555	1,309	238	0	4	3
234	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
235	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
236	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
237	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	7,329	6,171	1,123	2	21	13
238	39500	Laboratory Equipment	6.2	P, S, T & D Plant - Customer	3	2	0	0	0	0
239	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
240	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
241	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
242	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	67,831	57,113	10,390	15	195	118
243	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
244	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
245	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
246	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	6,975	5,873	1,068	1	20	12
247	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	(5,746)	(4,838)	(880)	(1)	(17)	(10)
248	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	143,708	121,001	22,013	31	414	249
249	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	68,397	57,589	10,477	15	197	119
250	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	12,239	10,305	1,875	3	35	21
251	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
252	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
253	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	23,650	19,913	3,623	5	68	41
254	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	(2,678)	(2,255)	(410)	(1)	(8)	(5)
255	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	2,873,124	2,419,143	440,104	614	8,278	4,984
256	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	4,112	3,462	630	1	12	7
257	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
258		Retirement Work in Progress	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
259										
260		Total General Plant			3,654,193	3,076,796	559,748	781	10,529	6,339
261										
262		TOTAL RESERVE FOR DEPRECIATION - CUSTOMER			150,156,279	120,785,963	28,239,002	50,076	674,907	406,331

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
263		Intangible Plant:								
264										
265	30100	Organization	6.4	P, S, T & D Plant - Demand	2,402	1,297	800	-	305	-
266	30200	Franchises & Consents	6.4	P, S, T & D Plant - Demand	34,556	18,659	11,515	-	4,382	-
267	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
268										
269		Total Intangible Plant:			36,958	19,955	12,315	0	4,687	0
270										
271		Production Plant:								
272										
273	32520	Producing Leaseholds	3.0	Peak Day	0	-	-	-	-	-
274	32540	Rights of Ways	3.0	Peak Day	0	-	-	-	-	-
275	33100	Production Gas Wells Equipment	3.0	Peak Day	0	-	-	-	-	-
276	33201	Field Lines	3.0	Peak Day	0	-	-	-	-	-
277	33202	Tributary Lines	3.0	Peak Day	0	-	-	-	-	-
278	33400	Field Meas. & Reg. Sta. Equip	3.0	Peak Day	0	-	-	-	-	-
279	33600	Purification Equipment	3.0	Peak Day	0	-	-	-	-	-
280										
281		Total Production Plant			0	0	0	0	0	0
282										
283		Storage Plant:								
284										
285	35010	Land	3.0	Peak Day	0	-	-	-	-	-
286	35020	Rights of Way	3.0	Peak Day	2,100	1,134	700	-	266	-
287	35100	Structures and Improvements	3.0	Peak Day	3,931	2,123	1,310	-	499	-
288	35102	Compression Station Equipment	3.0	Peak Day	60,220	32,516	20,067	-	7,637	-
289	35103	Meas. & Reg. Sta. Structues	3.0	Peak Day	10,432	5,633	3,476	-	1,323	-
290	35104	Other Structures	3.0	Peak Day	53,002	28,618	17,662	-	6,722	-
291	35200	Wells \ Rights of Way	3.0	Peak Day	1,231,874	665,155	410,496	-	156,224	-
292	35201	Well Construction	3.0	Peak Day	751,264	405,647	250,343	-	95,274	-
293	35202	Well Equipment	3.0	Peak Day	237,180	128,066	79,035	-	30,079	-
294	35203	Cushion Gas	3.0	Peak Day	351,499	189,793	117,130	-	44,577	-
295	35210	Leaseholds	3.0	Peak Day	83,664	45,175	27,879	-	10,610	-
296	35211	Storage Rights	3.0	Peak Day	22,346	12,066	7,446	-	2,834	-
297	35301	Field Lines	3.0	Peak Day	52,783	28,500	17,589	-	6,694	-
298	35302	Tributary Lines	3.0	Peak Day	76,873	41,508	25,616	-	9,749	-
299	35400	Compressor Station Equipment	3.0	Peak Day	341,086	184,170	113,660	-	43,256	-
300	35500	Meas & Reg. Equipment	3.0	Peak Day	83,530	45,102	27,835	-	10,593	-
301	35600	Purification Equipment	3.0	Peak Day	161,314	87,102	53,754	-	20,458	-
302										
303		Total Storage Plant			3,523,099	1,902,309	1,173,997	-	446,793	-
304										
305		Transmission:								
306										
307	36510	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
308	36520	Rights of Way	3.0	Peak Day	587,414	317,176	195,743	-	74,495	-
309	36602	Structures & Improvements	3.0	Peak Day	29,122	15,724	9,704	-	3,693	-
310	36603	Other Structues	3.0	Peak Day	62,894	33,960	20,958	-	7,976	-
311	36700	Mains Cathodic Protection	3.0	Peak Day	33,163	17,907	11,051	-	4,206	-
312	36701	Mains - Steel	3.0	Peak Day	18,044,112	9,742,978	6,012,813	-	2,288,321	-
313	36703	Mains - Anodes	3.0	Peak Day	11,180	6,037	3,725	-	1,418	-
314	36900	Meas. & Reg. Equipment	3.0	Peak Day	620,559	335,073	206,788	-	78,698	-
315	36901	Meas. & Reg. Equipment	3.0	Peak Day	2,023,747	1,092,729	674,370	-	256,648	-
316										
317		Total Transmission Plant			21,412,190	11,561,582	7,135,153	-	2,715,455	-
318										
319		Distribution:								
320										
321	37400	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
322	37401	Land	3.0	Peak Day	0	-	-	-	-	-
323	37402	Land Rights	3.0	Peak Day	262,902	141,955	87,607	-	33,341	-
324	37403	Land Other	3.0	Peak Day	0	-	-	-	-	-
325	37500	Structures & Improvements	3.0	Peak Day	55,659	30,053	18,547	-	7,059	-
326	37501	Structures & Improvements T.B.	3.0	Peak Day	33,373	18,020	11,121	-	4,232	-
327	37502	Land Rights	3.0	Peak Day	16,615	8,972	5,537	-	2,107	-
328	37503	Improvements	3.0	Peak Day	900	486	300	-	114	-
329	37600	Mains Cathodic Protection	3.0	Peak Day	731,509	394,981	243,760	-	92,769	-
330	37601	Mains - Steel	3.0	Peak Day	12,632,065	6,820,725	4,209,365	-	1,601,975	-
331	37602	Mains - Plastic	3.0	Peak Day	11,449,024	6,181,938	3,815,142	-	1,451,944	-
332	37603	Mains - Anodes	3.0	Peak Day	755,518	407,944	251,760	-	95,813	-
333	37604	Mains - Leak Clamps	3.0	Peak Day	2,291,694	1,237,408	763,658	-	290,628	-
334	37800	Meas & Reg. Sta. Equip - General	3.0	Peak Day	2,158,273	1,165,367	719,198	-	273,708	-
335	37900	Meas & Reg. Sta. Equip - City Gate	3.0	Peak Day	594,506	321,005	198,106	-	75,394	-
336	37905	Meas & Reg. Sta. Equipment T.b.	3.0	Peak Day	436,031	235,436	145,298	-	55,297	-
337	38000	Services	99.0	-	0	-	-	-	-	-
338	38100	Meters	99.0	-	0	-	-	-	-	-
339	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
340	38300	House Regulators	99.0	-	0	-	-	-	-	-
341	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
342	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
343	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
344										
345		Total Distribution Plant			31,418,069	16,964,289	10,469,397	-	3,984,382	-

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Customer/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
346											
347		General:									
348											
349	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
350	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	567,551	306,451	189,124	-	71,976	-	
351	39002	Structures - Brick	6.4	P, S, T & D Plant - Demand	34,257	18,497	11,416	-	4,344	-	
352	39003	Improvements	6.4	P, S, T & D Plant - Demand	96,610	52,165	32,193	-	12,252	-	
353	39003	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	2,571	1,388	857	-	326	-	
354	39004	Improvement to Leased Premises	6.4	P, S, T & D Plant - Demand	365,360	197,277	121,748	-	46,334	-	
355	39009	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	424,902	229,427	141,589	-	53,885	-	
356	39100	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
357	39102	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
358	39103	Transportation Equipment	6.4	P, S, T & D Plant - Demand	21,860	11,803	7,284	-	2,772	-	
359	39200	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
360	39201	Trailers	6.4	P, S, T & D Plant - Demand	2,496	1,348	832	-	317	-	
361	39202	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
362	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	964,650	520,866	321,449	-	122,335	-	
363	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
364	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
365	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
366	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
367	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	105,714	57,081	35,227	-	13,406	-	
368	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
369	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
370	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
371	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	446,596	241,141	148,818	-	56,636	-	
372	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
373	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	6,226	3,362	2,075	-	790	-	
374	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
375	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
376	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
377	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
378	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	152,812	82,511	50,921	-	19,379	-	
379	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
380	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
381	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
382		Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
383		Retirement Work in Progress	6.4	P, S, T & D Plant - Demand	(477,340)	(257,741)	(159,063)	-	(60,535)	-	
384		AR 15 general plant amortization	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
385											
386		Total General Plant			2,714,264	1,465,576	904,470	-	344,218	-	
387											
388		TOTAL DIRECT RESERVE FOR DEPRECIATION			59,104,580	31,913,712	19,695,333	0	7,495,535	0	
389											
390		Kentucky Mid-States General Office:									
391											
392		Intangible Plant:									
393											
394	30100	Organization	99.0	-	0	-	-	-	-	-	
395	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
396	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
397											
398		Total Intangible Plant:									
399											
400		General:									
401											
402	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
403	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	17,309	9,346	5,768	-	2,195	-	
404	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
405	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
406	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	2,210	1,193	737	-	280	-	
407	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	5,595	3,021	1,864	-	710	-	
408	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	1,228	663	409	-	156	-	
409	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
410	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
411	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	(286)	(154)	(95)	-	(36)	-	
412	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
413	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
414	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
415	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	7,760	4,190	2,586	-	984	-	
416	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	431	233	144	-	55	-	
417	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
418	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
419	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
420	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	(3,179)	(1,717)	(1,059)	-	(403)	-	
421	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
422	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
423	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
424	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	(18,297)	(9,879)	(6,097)	-	(2,320)	-	
425	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
426	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
427	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
428	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	2,814	1,519	938	-	357	-	
429	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
430	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
431	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
432	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	6,270	3,386	2,089	-	795	-	
433	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
434	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
435	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
436	ADJ	WTW Adjustment	6.4	P, S, T & D Plant - Demand	7,566	4,086	2,521	-	960	-	
437											
438		Total General Plant			29,423	15,887	9,805	-	3,731	-	

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Customer/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
439											
440			Shared Services General Office:								
441											
442			General:								
443											
444		37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
445		39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	45,652	24,650	15,213	-	5,790	-
446		36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
447		37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
448		39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
449		39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	143,139	77,288	47,698	-	18,153	-
450		39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	55,656	30,052	18,546	-	7,058	-
451		39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	0	0	-	0	-
452		39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	0	0	-	0	-
453		39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	2,996	1,618	999	-	380	-
454		39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
455		39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
456		39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
457		39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	365	197	122	-	46	-
458		39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
459		39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
460		39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
461		39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
462		39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	2,221	1,199	740	-	282	-
463		39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
464		39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
465		39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
466		39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	730	394	243	-	93	-
467		39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	(0)	(0)	(0)	-	(0)	-
468		39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	171,636	92,675	57,194	-	21,767	-
469		39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	202,774	109,488	67,570	-	25,715	-
470		39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	27,603	14,904	9,198	-	3,501	-
471		39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
472		39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
473		39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	25,036	13,518	8,343	-	3,175	-
474		39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	916	495	305	-	116	-
475		39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
476		39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	1,422,490	768,078	474,014	-	180,398	-
477		39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
478			Retirement Work in Progress	6.4	P, S, T & D Plant - Demand	2,645	1,428	881	-	335	-
479											
480			Total General Plant			2,103,860	1,135,986	701,066	-	266,808	-
481											
482			Shared Services Customer Support:								
483											
484			General:								
485											
486		37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
487		39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
488		36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	121,315	65,505	40,426	-	15,385	-
489		37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
490		39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
491		39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	39,475	21,315	13,154	-	5,006	-
492		39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	28,556	15,419	9,516	-	3,621	-
493		39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
494		39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
495		39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	649	350	216	-	82	-
496		39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
497		39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
498		39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
499		39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	3,059	1,652	1,019	-	388	-
500		39500	Laboratory Equipment	6.4	P, S, T & D Plant - Demand	1	1	0	-	0	-
501		39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
502		39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
503		39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
504		39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	28,309	15,285	9,433	-	3,590	-
505		39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
506		39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
507		39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
508		39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	2,911	1,572	970	-	369	-
509		39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	(2,398)	(1,295)	(799)	-	(304)	-
510		39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	59,975	32,384	19,986	-	7,606	-
511		39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	28,545	15,413	9,512	-	3,620	-
512		39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	5,108	2,758	1,702	-	648	-
513		39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
514		39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
515		39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	9,870	5,329	3,289	-	1,252	-
516		39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	(1,118)	(603)	(372)	-	(142)	-
517		39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	1,199,078	647,446	399,567	-	152,065	-
518		39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	1,716	927	572	-	218	-
519		39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
520			Retirement Work in Progress	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
521											
522			Total General Plant			1,525,051	823,456	508,191	-	193,404	-
523											
524			TOTAL RESERVE FOR DEPRECIATION - DEMAND			62,762,914	33,889,041	20,914,395	0	7,959,478	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
525		Intangible Plant:								
526										
527	30100	Organization	6.6	P, S, T & D Plant - Commodity	173	66	43	1	31	32
528	30200	Franchises & Consents	6.6	P, S, T & D Plant - Commodity	2,496	948	626	13	445	464
529	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
530										
531		Total Intangible Plant:			2,670	1,014	669	14	475	496
532										
533		Production Plant:								
534										
535	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
536	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
537	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
538	33201	Field Lines	99.0	-	0	-	-	-	-	-
539	33202	Tributary Lines	1.2	Sales Mcf	0	-	-	-	-	-
540	33400	Field Meas. & Reg. Sta. Equip	1.2	Sales Mcf	0	-	-	-	-	-
541	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
542										
543		Total Production Plant			0	0	0	0	0	0
544										
545		Storage Plant:								
546										
547	35010	Land	1.5	Winter Volumes	0	-	-	-	-	-
548	35020	Rights of Way	1.5	Winter Volumes	2,100	798	527	11	374	390
549	35100	Structures and Improvements	1.5	Winter Volumes	3,931	1,494	986	21	700	731
550	35102	Compression Station Equipment	1.5	Winter Volumes	60,220	22,878	15,099	325	10,725	11,193
551	35103	Meas. & Reg. Sta. Structues	1.5	Winter Volumes	10,432	3,963	2,616	56	1,858	1,939
552	35104	Other Structures	1.5	Winter Volumes	53,002	20,135	13,289	286	9,439	9,852
553	35200	Wells \ Rights of Way	1.5	Winter Volumes	1,231,874	467,993	308,863	6,654	219,388	228,976
554	35201	Well Construction	1.5	Winter Volumes	751,264	285,408	188,361	4,058	133,795	139,642
555	35202	Well Equipment	1.5	Winter Volumes	237,180	90,106	59,467	1,281	42,240	44,086
556	35203	Cushion Gas	1.5	Winter Volumes	351,499	133,536	88,130	1,899	62,600	65,335
557	35210	Leaseholds	1.5	Winter Volumes	83,664	31,784	20,977	452	14,900	15,551
558	35211	Storage Rights	1.5	Winter Volumes	22,346	8,489	5,603	121	3,980	4,154
559	35301	Field Lines	1.5	Winter Volumes	52,783	20,052	13,234	285	9,400	9,811
560	35302	Tributary Lines	1.5	Winter Volumes	76,873	29,204	19,274	415	13,691	14,289
561	35400	Compressor Station Equipment	1.5	Winter Volumes	341,086	129,580	85,519	1,842	60,745	63,400
562	35500	Meas & Reg. Equipment	1.5	Winter Volumes	83,530	31,733	20,943	451	14,876	15,526
563	35600	Purification Equipment	1.5	Winter Volumes	161,314	61,284	40,446	871	28,729	29,984
564										
565		Total Storage Plant			3,523,099	1,338,437	883,332	19,031	627,439	654,860
566										
567		Transmission:								
568										
569	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
570	36520	Rights of Way	99.0	-	0	-	-	-	-	-
571	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
572	36603	Other Structues	99.0	-	0	-	-	-	-	-
573	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
574	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
575	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
576	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
577	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
578										
579		Total Transmission Plant			0	-	-	-	-	-
580										
581		Distribution:								
582										
583	37400	Land & Land Rights	99.0	-	0	-	-	-	-	-
584	37401	Land	99.0	-	0	-	-	-	-	-
585	37402	Land Rights	1.0	Mcf	0	-	-	-	-	-
586	37403	Land Other	99.0	-	0	-	-	-	-	-
587	37500	Structures & Improvements	1.0	Mcf	0	-	-	-	-	-
588	37501	Structures & Improvements T.B.	1.0	Mcf	0	-	-	-	-	-
589	37502	Land Rights	1.0	Mcf	0	-	-	-	-	-
590	37503	Improvements	1.0	Mcf	0	-	-	-	-	-
591	37600	Mains Cathodic Protection	1.0	Mcf	0	-	-	-	-	-
592	37601	Mains - Steel	1.0	Mcf	0	-	-	-	-	-
593	37602	Mains - Plastic	1.0	Mcf	0	-	-	-	-	-
594	37603	Mains - Anodes	1.0	Mcf	0	-	-	-	-	-
595	37604	Mains - Leak Clamps	1.0	Mcf	0	-	-	-	-	-
596	37800	Meas & Reg. Sta. Equip - General	1.0	Mcf	0	-	-	-	-	-
597	37900	Meas & Reg. Sta. Equip - City Gate	1.0	Mcf	0	-	-	-	-	-
598	37905	Meas & Reg. Sta. Equipment T.b.	1.0	Mcf	0	-	-	-	-	-
599	38000	Services	99.0	-	0	-	-	-	-	-
600	38100	Meters	99.0	-	0	-	-	-	-	-
601	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
602	38300	House Regulators	99.0	-	0	-	-	-	-	-
603	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
604	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
605	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
606										
607		Total Distribution Plant			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

608										
609		General:								
610										
611	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
612	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	40,996	15,575	10,279	221	7,301	7,620
613	39002	Structures - Brick	6.6	P, S, T & D Plant - Commodity	2,475	940	620	13	441	460
614	39003	Improvements	6.6	P, S, T & D Plant - Commodity	6,978	2,651	1,750	38	1,243	1,297
615	39003	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	186	71	47	1	33	35
616	39004	Improvement to Leased Premises	6.6	P, S, T & D Plant - Commodity	26,391	10,026	6,617	143	4,700	4,906
617	39009	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	30,692	11,660	7,695	166	5,466	5,705
618	39100	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
619	39102	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
620	39103	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	1,579	600	396	9	281	293
621	39200	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
622	39201	Trailers	6.6	P, S, T & D Plant - Commodity	180	69	45	1	32	34
623	39202	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
624	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	69,680	26,472	17,471	376	12,410	12,952
625	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
626	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
627	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
628	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
629	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	7,636	2,901	1,915	41	1,360	1,419
630	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
631	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
632	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
633	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	32,259	12,255	8,088	174	5,745	5,996
634	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
635	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	450	171	113	2	80	84
636	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
637	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
638	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
639	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
640	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	11,038	4,193	2,768	60	1,966	2,052
641	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
642	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
643	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
644		Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
645	ADJ	WTW Adjustment	6.6	P, S, T & D Plant - Commodity	(34,480)	(13,099)	(8,645)	(186)	(6,141)	(6,409)
646		AR 15 general plant amortization	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
647										
648		Total General Plant			196,061	74,484	49,158	1,059	34,917	36,443
649										
650		TOTAL DIRECT RESERVE FOR DEPRECIATION			3,721,829	1,413,935	933,159	20,104	662,832	691,799
651										
652		Kentucky Mid-States General Office:								
653										
654		Intangible Plant:								
655										
656	30100	Organization	99.0	-	0	-	-	-	-	-
657	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
658	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
659										
660		Total Intangible Plant:								
661										
662		General:								
663										
664	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
665	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	1,250	475	313	7	223	232
666	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
667	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
668	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	160	61	40	1	28	30
669	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	404	154	101	2	72	75
670	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	89	34	22	0	16	16
671	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
672	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
673	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	(21)	(8)	(5)	(0)	(4)	(4)
674	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
675	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
676	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
677	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	561	213	141	3	100	104
678	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	31	12	8	0	6	6
679	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
680	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
681	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
682	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	(230)	(87)	(58)	(1)	(41)	(43)
683	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
684	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
685	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
686	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	(1,322)	(502)	(331)	(7)	(235)	(246)
687	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
688	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
689	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
690	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	203	77	51	1	36	38
691	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
692	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
693	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
694	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	453	172	114	2	81	84
695	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
696	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
697	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
698		Retirement Work in Progress	6.6	P, S, T & D Plant - Commodity	547	208	137	3	97	102
699										
700		Total General Plant			2,125	807	533	11	379	395

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF RESERVE FOR DEPRECIATION										
701										
702		Shared Services General Office:								
703										
704		General:								
705										
706	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
707	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	3,298	1,253	827	18	587	613
708	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
709	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
710	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
711	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	10,339	3,928	2,592	56	1,841	1,922
712	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	4,020	1,527	1,008	22	716	747
713	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
714	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
715	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	216	82	54	1	39	40
716	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
717	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
718	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
719	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	26	10	7	0	5	5
720	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
721	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
722	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
723	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
724	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	160	61	40	1	29	30
725	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
726	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
727	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
728	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	53	20	13	0	9	10
729	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	(0)	(0)	(0)	(0)	(0)	(0)
730	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	12,398	4,710	3,108	67	2,208	2,304
731	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	14,647	5,564	3,672	79	2,609	2,723
732	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	1,994	757	500	11	355	371
733	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
734	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
735	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	1,808	687	453	10	322	336
736	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	66	25	17	0	12	12
737	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
738	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	102,751	39,036	25,762	555	18,299	19,099
739	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
740		Retirement Work in Progress	6.6	P, S, T & D Plant - Commodity	191	73	48	1	34	36
741										
742		Total General Plant			151,969	57,734	38,103	821	27,065	28,247
743					50,635	19,236	12,695	274	9,018	9,412
744		Shared Services Customer Support:								
745										
746		General:								
747										
748	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
749	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
750	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	8,763	3,329	2,197	47	1,561	1,629
751	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
752	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
753	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	2,851	1,083	715	15	508	530
754	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	2,063	784	517	11	367	383
755	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
756	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
757	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	47	18	12	0	8	9
758	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
759	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
760	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
761	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	221	84	55	1	39	41
762	39500	Laboratory Equipment	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
763	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
764	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
765	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
766	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	2,045	777	513	11	364	380
767	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
768	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
769	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
770	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	210	80	53	1	37	39
771	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	(173)	(66)	(43)	(1)	(31)	(32)
772	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	4,332	1,646	1,086	23	772	805
773	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	2,062	783	517	11	367	383
774	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	369	140	93	2	66	69
775	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
776	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
777	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	713	271	179	4	127	133
778	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	(81)	(31)	(20)	(0)	(14)	(15)
779	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	86,614	32,905	21,716	468	15,425	16,099
780	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	124	47	31	1	22	23
781	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
782		Retirement Work in Progress	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
783										
784		Total General Plant			110,160	41,850	27,620	595	19,619	20,476
785										
786		TOTAL RESERVE FOR DEPRECIATION - COMMODITY			3,986,083	1,514,326	999,414	21,532	709,893	740,918

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Total Reserve for Depreciation

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
787		Intangible Plant:								
788										
789	30100	Organization			8,330	6,208	1,725	2	352	42
790	30200	Franchises & Consents			119,853	89,324	24,824	31	5,065	608
791	30300	Misc Intangible Plant			0	-	-	-	-	-
792										
793		Total Intangible Plant:			128,182	95,532	26,550	33	5,418	650
794										
795		Production Plant:								
796										
797	32520	Producing Leaseholds			0	-	-	-	-	-
798	32540	Rights of Ways			0	-	-	-	-	-
799	33100	Production Gas Wells Equipment			0	-	-	-	-	-
800	33201	Field Lines			0	-	-	-	-	-
801	33202	Tributary Lines			0	-	-	-	-	-
802	33400	Field Meas. & Reg. Sta. Equip			0	-	-	-	-	-
803	33600	Purification Equipment			0	-	-	-	-	-
804										
805		Total Production Plant			0	0	0	0	0	0
806										
807		Storage Plant:								
808										
809	35010	Land			0	-	-	-	-	-
810	35020	Rights of Way			4,200	1,932	1,226	11	640	390
811	35100	Structures and Improvements			7,863	3,616	2,296	21	1,199	731
812	35102	Compression Station Equipment			120,440	55,394	35,166	325	18,362	11,193
813	35103	Meas. & Reg. Sta. Structues			20,864	9,596	6,092	56	3,181	1,939
814	35104	Other Structures			106,003	48,754	30,951	286	16,161	9,852
815	35200	Wells \ Rights of Way			2,463,749	1,133,148	719,358	6,654	375,612	228,976
816	35201	Well Construction			1,502,528	691,055	438,704	4,058	229,069	139,642
817	35202	Well Equipment			474,361	218,172	138,502	1,281	72,319	44,086
818	35203	Cushion Gas			702,999	323,329	205,260	1,899	107,176	65,335
819	35210	Leaseholds			167,328	76,959	48,856	452	25,510	15,551
820	35211	Storage Rights			44,691	20,555	13,049	121	6,813	4,154
821	35301	Field Lines			105,566	48,553	30,823	285	16,094	9,811
822	35302	Tributary Lines			153,747	70,713	44,891	415	23,440	14,289
823	35400	Compressor Station Equipment			682,172	313,750	199,179	1,842	104,001	63,400
824	35500	Meas & Reg. Equipment			167,060	76,836	48,778	451	25,469	15,526
825	35600	Purification Equipment			322,628	148,386	94,200	871	49,186	29,984
826										
827		Total Storage Plant			7,046,197	3,240,745	2,057,329	19,031	1,074,232	654,860
828										
829		Transmission:								
830										
831	36510	Land & Land Rights			0	-	-	-	-	-
832	36520	Rights of Way			587,414	317,176	195,743	-	74,495	-
833	36602	Structures & Improvements			29,122	15,724	9,704	-	3,693	-
834	36603	Other Structues			62,894	33,960	20,958	-	7,976	-
835	36700	Mains Cathodic Protection			33,163	17,907	11,051	-	4,206	-
836	36701	Mains - Steel			18,044,112	9,742,978	6,012,813	-	2,288,321	-
837	36703	Mains - Anodes			11,180	6,037	3,725	-	1,418	-
838	36900	Meas. & Reg. Equipment			620,559	335,073	206,788	-	78,698	-
839	36901	Meas. & Reg. Equipment			2,023,747	1,092,729	674,370	-	256,648	-
840										
841		Total Transmission Plant			21,412,190	11,561,582	7,135,153	-	2,715,455	-
842										
843		Distribution:								
844										
845	37400	Land & Land Rights			0	-	-	-	-	-
846	37401	Land			0	-	-	-	-	-
847	37402	Land Rights			644,160	480,381	130,021	18	33,590	150
848	37403	Land Other			0	-	-	-	-	-
849	37500	Structures & Improvements			136,375	101,701	27,527	4	7,111	32
850	37501	Structures & Improvements T.B.			81,770	60,980	16,505	2	4,264	19
851	37502	Land Rights			40,711	30,360	8,217	1	2,123	9
852	37503	Improvements			2,204	1,644	445	0	115	1
853	37600	Mains Cathodic Protection			1,792,334	1,336,630	361,775	51	93,461	417
854	37601	Mains - Steel			30,950,942	23,081,616	6,247,318	887	1,613,926	7,195
855	37602	Mains - Plastic			28,052,270	20,919,936	5,662,234	804	1,462,776	6,521
856	37603	Mains - Anodes			1,851,162	1,380,501	373,649	53	96,528	430
857	37604	Mains - Leak Clamps			5,615,083	4,187,439	1,133,381	161	292,797	1,305
858	37800	Meas & Reg. Sta. Equip - General			5,288,177	3,943,649	1,067,396	152	275,750	1,229
859	37900	Meas & Reg. Sta. Equip - City Gate			1,456,651	1,086,295	294,019	42	75,957	339
860	37905	Meas & Reg. Sta. Equipment T.b.			1,068,358	796,726	215,644	31	55,709	248
861	38000	Services			38,828,841	34,466,716	4,319,663	1,879	25,331	15,251
862	38100	Meters			23,998,006	16,708,691	6,815,221	20,985	282,830	170,279
863	38200	Meter Installaitons			22,719,274	15,818,369	6,452,072	19,867	267,759	161,206
864	38300	House Regulators			469,350	326,786	133,291	410	5,532	3,330
865	38400	House Reg. Installations			130,024	90,530	36,926	114	1,532	923
866	38500	Ind. Meas. & Reg. Sta. Equipment			3,090,645	-	3,060,560	1,332	17,948	10,805
867	38600	Other Prop. On Cust. Prem			0	-	-	-	-	-
868										
869		Total Distribution Plant			166,216,337	124,818,952	36,355,865	46,793	4,615,038	379,689

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF RESERVE FOR DEPRECIATION										
870										
871		General:								
872										
873	38900	Land & Land Rights			0	-	-	-	-	-
874	39000	Structures & Improvements			1,968,463	1,467,062	407,714	512	83,195	9,979
875	39002	Structures - Brick			118,817	88,552	24,610	31	5,022	602
876	39003	Improvements			335,075	249,726	69,402	87	14,162	1,699
877	39003	Air Conditioning Equipment			8,916	6,645	1,847	2	377	45
878	39004	Improvement to Leased Premises			1,267,195	944,419	262,466	330	53,557	6,424
879	39009	Office Furniture & Equipment			1,473,706	1,098,328	305,239	383	62,285	7,471
880	39100	Remittance Processing Equip			0	-	-	-	-	-
881	39102	Office Machines			0	-	-	-	-	-
882	39103	Transportation Equipment			75,817	56,505	15,703	20	3,204	384
883	39200	Trucks			0	-	-	-	-	-
884	39201	Trailers			8,658	6,453	1,793	2	366	44
885	39202	Stores Equipment			0	-	-	-	-	-
886	39400	Tools, Shop & Garage Equipment			3,345,740	2,493,523	692,980	871	141,405	16,962
887	39600	Power Operated Equipment			0	-	-	-	-	-
888	39603	Ditchers			0	-	-	-	-	-
889	39604	Backhoes			0	-	-	-	-	-
890	39605	Welders			0	-	-	-	-	-
891	39700	Communication Equipment			366,653	273,260	75,942	95	15,496	1,859
892	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
893	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
894	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
895	39800	Miscellaneous Equipment			1,548,948	1,154,404	320,823	403	65,465	7,853
896	39900	Other Tangible Property			0	-	-	-	-	-
897	39901	Other Tangible Property - Servers - H/W			21,595	16,094	4,473	6	913	109
898	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
899	39903	Other Tangible Property - Network - H/W			0	-	-	-	-	-
900	39904	Other Tang. Property - CPU			0	-	-	-	-	-
901	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
902	39906	Other Tang. Property - PC Hardware			530,003	395,003	109,776	138	22,400	2,687
903	39907	Other Tang. Property - PC Software			0	-	-	-	-	-
904	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
905	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
906		Other Tang. Property - General Startup Costs			0	-	-	-	-	-
907	ADJ	WTW Adjustment			(1,655,581)	(1,233,876)	(342,909)	(431)	(69,972)	(8,393)
908		AR 15 general plant amortization			0	-	-	-	-	-
909										
910		Total General Plant			9,414,005	7,016,097	1,949,859	2,449	397,874	47,725
911										
912		TOTAL DIRECT RESERVE FOR DEPRECIATION			204,216,911	146,732,909	47,524,756	68,306	8,808,016	1,082,924
913										
914		Kentucky Mid-States General Office:								
915										
916		Intangible Plant:								
917										
918	30100	Organization			0	-	-	-	-	-
919	30200	Franchises & Consents			0	-	-	-	-	-
920	30300	Misc Intangible Plant			0	-	-	-	-	-
921										
922		Total Intangible Plant:								
923										
924		General:								
925										
926	37400	Land & Land Rights			0	-	-	-	-	-
927	39001	Structures Frame			60,032	44,741	12,434	16	2,537	304
928	36602	Structures & Improvements			0	-	-	-	-	-
929	38900	Land & Land Rights			0	-	-	-	-	-
930	39004	Air Conditioning Equipment			7,666	5,713	1,588	2	324	39
931	39009	Improvement to leased Premises			19,405	14,462	4,019	5	820	98
932	39100	Office Furniture & Equipment			4,261	3,175	882	1	180	22
933	39102	Remittance Processing Equip			0	-	-	-	-	-
934	39103	Office Machines			0	-	-	-	-	-
935	39200	Transportation Equipment			(990)	(738)	(205)	(0)	(42)	(5)
936	39201	Trucks			0	-	-	-	-	-
937	39202	Trailers			0	-	-	-	-	-
938	39300	Stores Equipment			0	-	-	-	-	-
939	39400	Tools, Shop & Garage Equipment			26,914	20,059	5,575	7	1,138	136
940	39600	Power Operated Equipment			1,496	1,115	310	0	63	8
941	39603	Ditchers			0	-	-	-	-	-
942	39604	Backhoes			0	-	-	-	-	-
943	39605	Welders			0	-	-	-	-	-
944	39700	Communication Equipment			(11,027)	(8,218)	(2,284)	(3)	(466)	(56)
945	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
946	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
947	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
948	39800	Miscellaneous Equipment			(63,459)	(47,295)	(13,144)	(17)	(2,682)	(322)
949	39900	Other Tangible Property			0	-	-	-	-	-
950	39901	Other Tangible Property - Servers - H/W			0	-	-	-	-	-
951	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
952	39903	Other Tangible Property - Network - H/W			9,760	7,274	2,022	3	413	49
953	39904	Other Tang. Property - CPU			0	-	-	-	-	-
954	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
955	39906	Other Tang. Property - PC Hardware			0	-	-	-	-	-
956	39907	Other Tang. Property - PC Software			21,748	16,208	4,504	6	919	110
957	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
958	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
959	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
960		Retirement Work in Progress			26,243	19,558	5,436	7	1,109	133
961										
962		Total General Plant			102,049	76,056	21,137	27	4,313	517

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

963										
964		Shared Services General Office:								
965										
966		General:								
967										
968	37400	Land & Land Rights			0	-	-	-	-	-
969	39000	Structures & Improvements			158,337	118,006	32,795	41	6,692	803
970	36602	Structures & Improvements			0	-	-	-	-	-
971	37503	Improvements			0	-	-	-	-	-
972	39004	Air Conditioning Equipment			0	-	-	-	-	-
973	39009	Improvement to leased Premises			496,454	369,999	102,827	129	20,982	2,517
974	39100	Office Furniture & Equipment			193,036	143,866	39,982	50	8,158	979
975	39102	Remittance Processing Equip			0	0	0	0	0	0
976	39103	Office Machines			0	0	0	0	0	0
977	39200	Transportation Equipment			10,393	7,746	2,153	3	439	53
978	39201	Trucks			0	-	-	-	-	-
979	39202	Trailers			0	-	-	-	-	-
980	39300	Stores Equipment			0	-	-	-	-	-
981	39400	Tools, Shop & Garage Equipment			1,267	944	262	0	54	6
982	39600	Power Operated Equipment			0	-	-	-	-	-
983	39603	Ditchers			0	-	-	-	-	-
984	39604	Backhoes			0	-	-	-	-	-
985	39605	Welders			0	-	-	-	-	-
986	39700	Communication Equipment			7,704	5,742	1,596	2	326	39
987	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
988	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
989	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
990	39800	Miscellaneous Equipment			2,531	1,886	524	1	107	13
991	39900	Other Tangible Property			(0)	(0)	(0)	(0)	(0)	(0)
992	39901	Other Tangible Property - Servers - H/W			595,292	443,661	123,299	155	25,159	3,018
993	39902	Other Tangible Property - Servers - S/W			703,290	524,150	145,668	183	29,724	3,565
994	39903	Other Tangible Property - Network - H/W			95,736	71,350	19,829	25	4,046	485
995	39904	Other Tang. Property - CPU			0	-	-	-	-	-
996	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
997	39906	Other Tang. Property - PC Hardware			86,835	64,717	17,986	23	3,670	440
998	39907	Other Tang. Property - PC Software			3,178	2,369	658	1	134	16
999	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
1000	39909	Other Tang. Property - Application Software			4,933,686	3,676,992	1,021,881	1,284	208,518	25,012
1001	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
1002		Retirement Work in Progress			9,173	6,836	1,900	2	388	47
1003										
1004		Total General Plant			7,296,912	5,438,264	1,511,360	1,899	308,397	36,992
1005										
1006		Shared Services Customer Support:								
1007										
1008		General:								
1009										
1010	37400	Land & Land Rights			0	-	-	-	-	-
1011	39001	Structures Frame			0	-	-	-	-	-
1012	36602	Structures & Improvements			420,763	313,587	87,150	109	17,783	2,133
1013	37503	Improvements			0	-	-	-	-	-
1014	39004	Air Conditioning Equipment			0	-	-	-	-	-
1015	39009	Improvement to leased Premises			136,913	102,039	28,358	36	5,786	694
1016	39100	Office Furniture & Equipment			99,042	73,815	20,514	26	4,186	502
1017	39102	Remittance Processing Equip			0	-	-	-	-	-
1018	39103	Office Machines			0	-	-	-	-	-
1019	39200	Transportation Equipment			2,251	1,677	466	1	95	11
1020	39201	Trucks			0	-	-	-	-	-
1021	39202	Trailers			0	-	-	-	-	-
1022	39300	Stores Equipment			0	-	-	-	-	-
1023	39400	Tools, Shop & Garage Equipment			10,609	7,907	2,197	3	448	54
1024	39500	Laboratory Equipment			4	3	1	0	0	0
1025	39603	Ditchers			0	-	-	-	-	-
1026	39604	Backhoes			0	-	-	-	-	-
1027	39605	Welders			0	-	-	-	-	-
1028	39700	Communication Equipment			98,184	73,175	20,336	26	4,150	498
1029	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
1030	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
1031	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
1032	39800	Miscellaneous Equipment			10,096	7,525	2,091	3	427	51
1033	39900	Other Tangible Property			(8,317)	(6,198)	(1,723)	(2)	(351)	(42)
1034	39901	Other Tangible Property - Servers - H/W			208,015	155,030	43,085	54	8,792	1,055
1035	39902	Other Tangible Property - Servers - S/W			99,003	73,785	20,506	26	4,184	502
1036	39903	Other Tangible Property - Network - H/W			17,716	13,203	3,669	5	749	90
1037	39904	Other Tang. Property - CPU			0	-	-	-	-	-
1038	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
1039	39906	Other Tang. Property - PC Hardware			34,234	25,514	7,091	9	1,447	174
1040	39907	Other Tang. Property - PC Software			(3,876)	(2,889)	(803)	(1)	(164)	(20)
1041	39908	Other Tang. Property - Mainframe S/W			4,158,816	3,099,494	861,387	1,082	175,769	21,083
1042	39909	Other Tang. Property - Application Software			5,952	4,436	1,233	2	252	30
1043	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
1044		Retirement Work in Progress			0	-	-	-	-	-
1045										
1046		Total General Plant			5,289,404	3,942,102	1,095,558	1,376	223,552	26,815
1047										
1048		TOTAL RESERVE FOR DEPRECIATION			216,905,276	156,189,331	50,152,810	71,608	9,344,278	1,147,249

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF OTHER RATE BASE

Customer

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Rate Base Additions:								
2									
3	Materials and Supplies - KY Direct	7.2	Allocated O&M Expenses - Cust	(5,337)	(4,571)	(748)	(1)	(11)	(7)
4	Materials and Supplies - KY Mid-States GO	7.2	Allocated O&M Expenses - Cust	99,463	85,185	13,938	15	203	122
5	Materials and Supplies - Shared Services GO	7.2	Allocated O&M Expenses - Cust	2,582	2,211	362	0	5	3
6	Materials and Supplies - Shared Services CS	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
7	Gas Storage Inventory	99.0	-	0	-	-	-	-	-
8	Prepayments - KY Direct	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
9	Prepayments - KY Mid-States GO	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
10	Prepayments - Shared Services GO	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
11	Prepayments - Shared Services CS	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
12	Cash Working Capital	7.2	Allocated O&M Expenses - Cust	(397,823)	(340,716)	(55,747)	(60)	(813)	(487)
13	Regulatory Assets	7.2	Allocated O&M Expenses - Cust	(672,958)	(576,356)	(94,302)	(102)	(1,375)	(824)
14									
15	Total Rate Base Additions			(974,073)	(834,246)	(136,497)	(147)	(1,990)	(1,193)
16									
17									
18	Rate Base Deductions:								
19									
20	Customer Advances - KY Direct	2.0	Bills	(736,136)	(653,437)	(81,894)	(36)	(480)	(289)
21	Customer Advances - KY Mid-States GO	2.0	Bills	0	-	-	-	-	-
22	Customer Advances - Shared Services GO	2.0	Bills	0	-	-	-	-	-
23	Customer Advances - Shared Services CS	2.0	Bills	0	-	-	-	-	-
24	ADIT - KY Direct (Div 009)	9.2	Allocated Net Plant - Cust	(65,324,593)	(55,730,346)	(9,331,093)	(11,648)	(156,990)	(94,516)
25	ADIT - Shared Services GO (Div 002)	9.2	Allocated Net Plant - Cust	(5,258,031)	(4,485,782)	(751,068)	(938)	(12,636)	(7,608)
26	ADIT - Shared Services CS (Div 012)	9.2	Allocated Net Plant - Cust	(339,870)	(289,953)	(48,548)	(61)	(817)	(492)
27	ADIT - KY Mid-States GO (Div 091)	9.2	Allocated Net Plant - Cust	(127,544)	(108,811)	(18,219)	(23)	(307)	(185)
28	Change in Net Operating Loss Carryforward	9.2	Allocated Net Plant - Cust	(4,015,100)	(3,425,400)	(573,525)	(716)	(9,649)	(5,809)
29									
30	Total Rate Base Deductions			(75,801,274)	(64,693,730)	(10,804,346)	(13,421)	(180,879)	(108,899)
31									
32									
33	TOTAL OTHER RB - CUSTOMER			(76,775,348)	(65,527,976)	(10,940,843)	(13,568)	(182,869)	(110,092)
34									
35	Interest on Customer Deposits	2.0	Bills	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF OTHER RATE BASE

Demand

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
35	Rate Base Additions:								
36									
37	Materials and Supplies - KY Direct	7.4	Allocated O&M Expenses - Demand	(2,536)	(1,369)	(845)	-	(322)	-
38	Materials and Supplies - KY Mid-States GO	7.4	Allocated O&M Expenses - Demand	47,260	25,518	15,748	-	5,993	-
39	Materials and Supplies - Shared Services GO	7.4	Allocated O&M Expenses - Demand	1,227	662	409	-	156	-
40	Materials and Supplies - Shared Services CS	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
41	Gas Storage Inventory	99.0	-	0	-	-	-	-	-
42	Prepayments - KY Direct	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
43	Prepayments - KY Mid-States GO	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
44	Prepayments - Shared Services GO	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
45	Prepayments - Shared Services CS	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
46	Cash Working Capital	7.4	Allocated O&M Expenses - Demand	(189,027)	(102,066)	(62,989)	-	(23,972)	-
47	Regulatory Assets	7.4	Allocated O&M Expenses - Demand	(319,758)	(172,654)	(106,552)	-	(40,551)	-
48									
49	Total Rate Base Additions			(462,834)	(249,909)	(154,229)	0	(58,696)	0
50									
51									
52	Rate Base Deductions:								
53									
54	Customer Advances - KY Direct	99.0	-	0	-	-	-	-	-
55	Customer Advances - KY Mid-States GO	99.0	-	0	-	-	-	-	-
56	Customer Advances - Shared Services GO	99.0	-	0	-	-	-	-	-
57	Customer Advances - Shared Services CS	99.0	-	0	-	-	-	-	-
58	ADIT - KY Direct (Div 009)	9.4	Allocated Net Plant - Demand	(27,250,344)	(14,713,913)	(9,080,593)	-	(3,455,839)	-
59	ADIT - Shared Services GO (Div 002)	9.4	Allocated Net Plant - Demand	(2,193,403)	(1,184,335)	(730,905)	-	(278,163)	-
60	ADIT - Shared Services CS (Div 012)	9.4	Allocated Net Plant - Demand	(141,778)	(76,553)	(47,244)	-	(17,980)	-
61	ADIT - KY Mid-States GO (Div 091)	9.4	Allocated Net Plant - Demand	(53,205)	(28,728)	(17,730)	-	(6,747)	-
62	Change in Net Operating Loss Carryforward	9.4	Allocated Net Plant - Demand	(1,674,910)	(904,373)	(558,128)	-	(212,409)	-
63									
64	Total Rate Base Deductions			(31,313,641)	(16,907,903)	(10,434,599)	-	(3,971,139)	-
65									
66									
67	TOTAL OTHER RB - DEMAND			(31,776,475)	(17,157,812)	(10,588,828)	-	(4,029,834)	-
68									
69	Interest on Customer Deposits	3.0	Peak Day	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF OTHER RATE BASE

Commodity

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
69	Rate Base Additions:								
70									
71	Materials and Supplies - KY Direct	7.6	Allocated O&M Expenses - Comm	(21,636)	(12,401)	(8,911)	(207)	(56)	(61)
72	Materials and Supplies - KY Mid-States GO	7.6	Allocated O&M Expenses - Comm	403,209	231,093	166,067	3,862	1,051	1,136
73	Materials and Supplies - Shared Services GO	7.6	Allocated O&M Expenses - Comm	10,467	5,999	4,311	100	27	29
74	Materials and Supplies - Shared Services CS	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
75	Gas Storage Inventory	1.0	Mcf	9,182,907	2,698,711	1,939,383	57,760	2,147,889	2,339,165
76	Prepayments - KY Direct	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
77	Prepayments - KY Mid-States GO	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
78	Prepayments - Shared Services GO	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
79	Prepayments - Shared Services CS	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
80	Cash Working Capital	7.6	Allocated O&M Expenses - Comm	(1,612,716)	(924,302)	(664,221)	(15,447)	(4,204)	(4,543)
81	Regulatory Assets	7.6	Allocated O&M Expenses - Comm	(2,728,075)	(1,563,552)	(1,123,597)	(26,131)	(7,111)	(7,684)
82									
83	Total Rate Base Additions			5,234,156	435,548	313,032	19,937	2,137,596	2,328,042
84									
85									
86	Rate Base Deductions:								
87									
88	Customer Advances - KY Direct	99.0	-	0	-	-	-	-	-
89	Customer Advances - KY Mid-States GO	99.0	-	0	-	-	-	-	-
90	Customer Advances - Shared Services GO	99.0	-	0	-	-	-	-	-
91	Customer Advances - Shared Services CS	99.0	-	0	-	-	-	-	-
92	ADIT - KY Direct (Div 009)	9.6	Allocated Net Plant - Comm	(2,038,972)	(774,612)	(511,223)	(11,014)	(363,127)	(378,996)
93	ADIT - Shared Services GO (Div 002)	9.6	Allocated Net Plant - Comm	(164,119)	(62,349)	(41,149)	(887)	(29,228)	(30,506)
94	ADIT - Shared Services CS (Div 012)	9.6	Allocated Net Plant - Comm	(10,608)	(4,030)	(2,660)	(57)	(1,889)	(1,972)
95	ADIT - KY Mid-States GO (Div 091)	9.6	Allocated Net Plant - Comm	(3,981)	(1,512)	(998)	(22)	(709)	(740)
96	Change in Net Operating Loss Carryforward	9.6	Allocated Net Plant - Comm	(125,323)	(47,611)	(31,422)	(677)	(22,319)	(23,295)
97									
98	Total Rate Base Deductions			(2,343,003)	(890,115)	(587,452)	(12,656)	(417,272)	(435,508)
99									
100									
101	TOTAL OTHER RB - COMMODITY			2,891,152	(454,566)	(274,419)	7,281	1,720,323	1,892,534
102									
103	Interest on Customer Deposits	1.0	Mcf	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF OTHER RATE BASE

Total Other Rate Base

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
103	Rate Base Additions:								
104									
105	Materials and Supplies - KY Direct			(29,510)	(18,341)	(10,504)	(208)	(389)	(67)
106	Materials and Supplies - KY Mid-States GO			549,932	341,796	195,754	3,877	7,248	1,258
107	Materials and Supplies - Shared Services GO			14,276	8,873	5,082	101	188	33
108	Materials and Supplies - Shared Services CS			0	-	-	-	-	-
109	Gas Storage Inventory			9,182,907	2,698,711	1,939,383	57,760	2,147,889	2,339,165
110	Prepayments - KY Direct			0	-	-	-	-	-
111	Prepayments - KY Mid-States GO			0	-	-	-	-	-
112	Prepayments - Shared Services GO			0	-	-	-	-	-
113	Prepayments - Shared Services CS			0	-	-	-	-	-
114	Cash Working Capital			(2,199,566)	(1,367,083)	(782,957)	(15,507)	(28,989)	(5,030)
115	Regulatory Assets			(3,720,791)	(2,312,562)	(1,324,451)	(26,232)	(49,038)	(8,508)
116									
117	Total Rate Base Additions			3,797,249	(648,606)	22,306	19,790	2,076,909	2,326,849
118									
119									
120	Rate Base Deductions:								
121									
122	Customer Advances - KY Direct			(736,136)	(653,437)	(81,894)	(36)	(480)	(289)
123	Customer Advances - KY Mid-States GO			0	-	-	-	-	-
124	Customer Advances - Shared Services GO			0	-	-	-	-	-
125	Customer Advances - Shared Services CS			0	-	-	-	-	-
126	ADIT - KY Direct (Div 009)			(94,613,910)	(71,218,871)	(18,922,909)	(22,662)	(3,975,955)	(473,513)
127	ADIT - Shared Services GO (Div 002)			(7,615,553)	(5,732,467)	(1,523,121)	(1,824)	(320,028)	(38,113)
128	ADIT - Shared Services CS (Div 012)			(492,256)	(370,537)	(98,452)	(118)	(20,686)	(2,464)
129	ADIT - KY Mid-States GO (Div 091)			(184,730)	(139,052)	(36,946)	(44)	(7,763)	(925)
130	Change in Net Operating Loss Carryforward			(5,815,333)	(4,377,385)	(1,163,074)	(1,393)	(244,377)	(29,104)
131									
132	Total Rate Base Deductions			(109,457,919)	(82,491,748)	(21,826,396)	(26,077)	(4,569,290)	(544,407)
133									
134									
135	TOTAL OTHER RB			(105,660,670)	(83,140,354)	(21,804,091)	(6,286)	(2,492,380)	1,782,442
136									
137	Interest on Customer Deposits			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Production & Gathering:								
2		Operation								
3	7500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
4	7510	Production Maps & Records	99.0	-	0	-	-	-	-	-
5	7530	Field Lines Expenses	99.0	-	0	-	-	-	-	-
6	7540	Field Compressor Station Expense	99.0	-	0	-	-	-	-	-
7	7550	Field Compressor Sta. Fuel & Pwr.	99.0	-	0	-	-	-	-	-
8	7560	Field Meas. & Regul. Station Exp	99.0	-	0	-	-	-	-	-
9	7570	Purification Expense	99.0	-	0	-	-	-	-	-
10	7590	Other Expenses	99.0	-	0	-	-	-	-	-
11		Maintenance								
12	7610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
13	7620	Structures and Improvements	99.0	-	0	-	-	-	-	-
14	7640	Field Line Maintenance	99.0	-	0	-	-	-	-	-
15	7650	Compressor Station Equip. Maint.	99.0	-	0	-	-	-	-	-
16	7660	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
17	7670	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
18	7680	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
19	7690	Gas Processed By Others	99.0	-	0	-	-	-	-	-
20		Total Production & Gathering			0	0	0	0	0	0
21										
22		Other Gas Supply Expenses:								
23		Operation								
24	8001	Intercompany Gas Well-head Purchases	99.0	-	0	-	-	-	-	-
25	8010	Natural gas field line purchases	99.0	-	0	-	-	-	-	-
26	8040	Natural gas city gate purchases	99.0	-	0	-	-	-	-	-
27	8050	Transmission-Operation supervision and engineering	99.0	-	0	-	-	-	-	-
28	8051	Other Gas Purchases / Gas Cost Adjustments	99.0	-	0	-	-	-	-	-
29	8052	PGA for Commercial	99.0	-	0	-	-	-	-	-
30	8053	PGA for Industrial	99.0	-	0	-	-	-	-	-
31	8054	PGA for Public Authority	99.0	-	0	-	-	-	-	-
32	8058	Unbilled PGA Cost	99.0	-	0	-	-	-	-	-
33	8059	PGA Offset to Unrecovered Gas Cost	99.0	-	0	-	-	-	-	-
34	8060	Exchange gas	99.0	-	0	-	-	-	-	-
35	8081	Gas withdrawn from storage-Debit	99.0	-	0	-	-	-	-	-
36	8082	Gas delivered to storage-Credit	99.0	-	0	-	-	-	-	-
37	8120	Gas used for other utility operations-Credit	99.0	-	0	-	-	-	-	-
38	8580	Transmission and compression of gas by others	99.0	-	0	-	-	-	-	-
39		Maintenance								
40	8350	Maint. Of Purch. Gas Meas. Sta.	99.0	-	0	-	-	-	-	-
41		Total Other Gas Supply Expenses			0	0	0	0	0	0
42										
43		Underground Storage:								
44		Operation								
45	8140	Storage-Operation supervision and engineering	99.0	-	0	-	-	-	-	-
46	8160	Wells expenses	99.0	-	0	-	-	-	-	-
47	8170	Lines expenses	99.0	-	0	-	-	-	-	-
48	8180	Compressor station expenses	99.0	-	0	-	-	-	-	-
49	8190	Compressor station fuel and power	99.0	-	0	-	-	-	-	-
50	8200	Storage-Measuring and regulating station expenses	99.0	-	0	-	-	-	-	-
51	8210	Storage-Purification expenses	99.0	-	0	-	-	-	-	-
52	8240	Storage-Other expenses	99.0	-	0	-	-	-	-	-
53	8250	Storage well royalties	99.0	-	0	-	-	-	-	-
54	8260	Rents	99.0	-	0	-	-	-	-	-
55		Maintenance								
56	8300	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
57	8310	Structures and Improvements	99.0	-	0	-	-	-	-	-
58	8320	Reservoirs & Wells Maintenance	99.0	-	0	-	-	-	-	-
59	8330	Line Maintenance	99.0	-	0	-	-	-	-	-
60	8340	Compressor Station Equip Maint	99.0	-	0	-	-	-	-	-
61	8350	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
62	8360	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
63	8410	Other storage expenses-Operation labor and expenses	99.0	-	0	-	-	-	-	-
64		Total Underground Storage Expense			0	0	0	0	0	0
65										
66		Transmission:								
67		Operation								
68	8500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
69	8510	System Control & Load Dispatching	99.0	-	0	-	-	-	-	-
70	8520	Communication Systems Expense	99.0	-	0	-	-	-	-	-
71	8530	Compressor Station Labor Expense	99.0	-	0	-	-	-	-	-
72	8540	Compressor Station Fuel Gas	99.0	-	0	-	-	-	-	-
73	8550	Compressor Station Fuel & Power	99.0	-	0	-	-	-	-	-
74	8560	Mains Expense	99.0	-	0	-	-	-	-	-
75	8570	Meas. & Regul. Station Expenses	99.0	-	0	-	-	-	-	-
76	8580	LDC Payment	99.0	-	0	-	-	-	-	-
77	8580	LDC Payment - A&G	99.0	-	0	-	-	-	-	-
78	8590	Other Expenses	99.0	-	0	-	-	-	-	-
79	8600	Rents	99.0	-	0	-	-	-	-	-
80		Maintenance								
81	8610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
82	8620	Structures and Improvements	99.0	-	0	-	-	-	-	-
83	8630	Mains	99.0	-	0	-	-	-	-	-
84	8640	Compressor Station Equip Maint	99.0	-	0	-	-	-	-	-
85	8650	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
86	8660	Communication Equipment Maintenance	99.0	-	0	-	-	-	-	-
87	8670	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
88		Total Transmission Expense			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF O&M EXPENSES										
89										
90		Distribution:								
91		Operation								
92	8700	Supervision and Engineering	10.2	Composite of Accts. 871-879 & 886-893 - Cust	1,316,806	1,128,381	183,048	238	3,207	1,931
93	8710	Distribution Load Dispatching	99.0	-	0	-	-	-	-	-
94	8711	Odorization	99.0	-	0	-	-	-	-	-
94	Accts. 376 & 3	Compressor Station Labor & Expenses	11.2	Composite of Accts. 376 & 380 - Cust	0	-	-	-	-	-
95	8740	Mains & Services	12.2	Composite of Accts. 374-379 - Cust	4,026,470	3,574,127	447,940	195	2,627	1,581
96	8750	Measuring and Regulating Station Exp. - Gen	11.2	Composite of Accts. 376 & 380 - Cust	805,849	715,318	89,650	39	526	317
97	8760	Measuring and Regulating Station Exp. - Ind.	2.2	Non-Residential Bills	523	-	518	0	3	2
98	8770	Measuring and Regulating Sta. Exp. - City Gate	11.2	Composite of Accts. 376 & 380 - Cust	3,248	2,883	361	0	2	1
99	8780	Meters and House Regulator Expense	13.2	Composite of Accts. 381-383 - Cust	938,471	653,413	266,517	821	11,060	6,659
100	8790	Customer Installations Expense	2.0	Bills	257	228	29	0	0	0
101	8800	Other Expense	10.2	Composite of Accts. 871-879 & 886-893 - Cust	1,898	1,626	264	0	5	3
102	8810	Rents	10.2	Composite of Accts. 871-879 & 886-893 - Cust	46,148	39,545	6,415	8	112	68
103		Maintenance								
104	8850	Maintenance Supervision and Engineering	10.2	Composite of Accts. 871-879 & 886-893 - Cust	0	-	-	-	-	-
105	8860	Maintenance of Structures and Improvements	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
106	8870	Maintenance of Mains	12.2	Composite of Accts. 374-379 - Cust	85,513	75,906	9,513	4	56	34
107	8890	Maintenance of compressor station equipment	99.0	-	0	-	-	-	-	-
108	8900	Maint. of Measuring and Regulating Station Equip. - General	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
109	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	2.2	Non-Residential Bills	135	-	133	0	1	0
110	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	12.2	Composite of Accts. 374-379 - Cust	105	93	12	0	0	0
111	8930	Maintenance of Services	14.2	Account 380 - Cust	0	-	-	-	-	-
112	8940	Maintenance of Meters and House Regulators	13.2	Composite of Accts. 381-383 - Cust	0	-	-	-	-	-
113	8950	Maintenance of Other Equipment	10.2	Composite of Accts. 871-879 & 886-893 - Cust	0	-	-	-	-	-
114		Total Distribution			7,225,423	6,191,522	1,004,400	1,306	17,599	10,596
115										
116		Customer Accounts:								
117	9010	Supervision	2.0	Bills	0	-	-	-	-	-
118	9020	Meter Reading Expense	2.0	Bills	735,288	652,684	81,800	36	480	289
119	9030	Customer Records and Collection Expenses	2.0	Bills	1,067,803	947,844	118,792	52	697	419
120	9040	Uncollectible Accounts	8.0	Customer Deposit Balances	731,532	496,144	235,187	-	200	-
121	9050	Miscellaneous Customer Accounts Expenses	2.0	Bills	0	-	-	-	-	-
122		Total Customer Accounts			2,534,624	2,096,673	435,779	87	1,376	708
123										
124		Customer Service and Information:								
125	9070	Supervision	2.0	Bills	0	-	-	-	-	-
126	9080	Customer Assistance Expenses	2.0	Bills	0	-	-	-	-	-
127	9090	Informational and Instructional Advertising Expenses	2.0	Bills	214,461	190,368	23,859	10	140	84
128	9100	Miscellaneous Customer Service and Informational Expenses	2.0	Bills	0	-	-	-	-	-
129		Total Customer Service and Information			214,461	190,368	23,859	10	140	84
130										
131		Sales:								
132	9110	Supervision	2.0	Bills	158,549	140,737	17,638	8	103	62
133	9120	Demonstrating and Selling Expenses	2.0	Bills	77,078	68,419	8,575	4	50	30
134	9130	Advertising Expenses	2.0	Bills	36,821	32,685	4,096	2	24	14
135	9160	Miscellaneous Sales Expenses	2.0	Bills	(188,721)	(167,520)	(20,995)	(9)	(123)	(74)
136		Total Sales			83,728	74,321	9,315	4	55	33
137										
138		Administrative & General:								
139		Operation								
140	9200	Administrative and General Salaries	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	0	-	-	-	-	-
141	9210	Office Supplies and Expenses	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	44,948	38,713	6,071	7	98	59
142	9220	Administrative Expenses Transferred - Customer Support	2.0	Bills	0	-	-	-	-	-
143	9220	Administrative Expenses Transferred - General	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	11,877,417	10,229,828	1,604,147	1,923	25,916	15,603
144	9230	Outside Services Employed	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	45,549	39,231	6,152	7	99	60
145	9240	Property Insurance	9.2	Allocated Net Plant - Cust	0	-	-	-	-	-
146	9250	Injuries and Damages	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	15,135	13,036	2,044	2	33	20
147	9260	Employee Pensions and Benefits	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	567,966	489,180	76,709	92	1,239	746
148	9270	Franchise Requirements	2.0	Bills	635	564	71	0	0	0
149	9280	Regulatory Commission Expenses	2.0	Bills	165,392	146,811	18,400	8	108	65
150	930.1	General Advertising Expenses	2.0	Bills	0	-	-	-	-	-
151	930.2	Miscellaneous General Expense	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	15,886	13,682	2,146	3	35	21
152	ADJ	Adjustments	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	(913,891)	(787,119)	(123,429)	(148)	(1,994)	(1,201)
153		Maintenance								
154	9320	Maintenance of General Plant	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	0	-	-	-	-	-
155		Total A&G			11,819,037	10,183,925	1,592,310	1,895	25,535	15,373
156										
157		TOTAL O&M EXPENSE - CUSTOMER			21,877,272	18,736,808	3,065,663	3,302	44,705	26,794

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
158		Production & Gathering:								
159		Operation								
160	7500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
161	7510	Production Maps & Records	99.0	-	0	-	-	-	-	-
162	7530	Field Lines Expenses	99.0	-	0	-	-	-	-	-
163	7540	Field Compressor Station Expense	99.0	-	0	-	-	-	-	-
164	7550	Field Compressor Sta. Fuel & Pwr.	99.0	-	0	-	-	-	-	-
165	7560	Field Meas. & Regul. Station Exp	99.0	-	0	-	-	-	-	-
166	7570	Purification Expense	99.0	-	0	-	-	-	-	-
167	7590	Other Expenses	99.0	-	0	-	-	-	-	-
168		Maintenance								
169	7610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
170	7620	Structures and Improvements	99.0	-	0	-	-	-	-	-
171	7640	Field Line Maintenance	99.0	-	0	-	-	-	-	-
172	7650	Compressor Station Equip. Maint.	99.0	-	0	-	-	-	-	-
173	7660	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
174	7670	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
175	7680	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
176	7690	Gas Processed By Others	99.0	-	0	-	-	-	-	-
177		Total Production & Gathering			0	0	0	0	0	0
178										
179		Other Gas Supply Expenses:								
180		Operation								
181	8001	Intercompany Gas Well-head Purchases	99.0	-	0	-	-	-	-	-
182	8010	Natural gas field line purchases	99.0	-	0	-	-	-	-	-
183	8040	Natural gas city gate purchases	99.0	-	0	-	-	-	-	-
184	8050	Transmission-Operation supervision and engineering	99.0	-	0	-	-	-	-	-
185	8051	Other Gas Purchases / Gas Cost Adjustments	99.0	-	0	-	-	-	-	-
186	8052	PGA for Commercial	99.0	-	0	-	-	-	-	-
187	8053	PGA for Industrial	99.0	-	0	-	-	-	-	-
188	8054	PGA for Public Authority	99.0	-	0	-	-	-	-	-
189	8058	Unbilled PGA Cost	99.0	-	0	-	-	-	-	-
190	8059	PGA Offset to Unrecovered Gas Cost	99.0	-	0	-	-	-	-	-
191	8060	Exchange gas	99.0	-	0	-	-	-	-	-
192	8081	Gas withdrawn from storage-Debit	99.0	-	0	-	-	-	-	-
193	8082	Gas delivered to storage-Credit	99.0	-	0	-	-	-	-	-
194	8120	Gas used for other utility operations-Credit	99.0	-	0	-	-	-	-	-
195	8580	Transmission and compression of gas by others	99.0	-	0	-	-	-	-	-
196		Maintenance								
197	8350	Maint. Of Purch. Gas Meas. Sta.	99.0	-	0	-	-	-	-	-
198		Total Other Gas Supply Expenses			0	0	0	0	0	0
199										
200		Underground Storage:								
201		Operation								
202	8140	Storage-Operation supervision and engineering	3.0	Peak Day	0	-	-	-	-	-
203	8160	Wells expenses	3.0	Peak Day	17,582	9,493	5,859	-	2,230	-
204	8170	Lines expenses	3.0	Peak Day	11,391	6,150	3,796	-	1,445	-
205	8180	Compressor station expenses	3.0	Peak Day	22,388	12,089	7,460	-	2,839	-
206	8190	Compressor station fuel and power	3.0	Peak Day	0	-	-	-	-	-
207	8200	Storage-Measuring and regulating station expenses	3.0	Peak Day	4,768	2,575	1,589	-	605	-
208	8210	Storage-Purification expenses	3.0	Peak Day	41,970	22,662	13,986	-	5,323	-
209	8240	Storage-Other expenses	3.0	Peak Day	0	-	-	-	-	-
210	8250	Storage well royalties	3.0	Peak Day	5,241	2,830	1,746	-	665	-
211	8260	Rents	3.0	Peak Day	0	-	-	-	-	-
212		Maintenance								
213	8300	Maint. Sup., & Eng.	3.0	Peak Day	0	-	-	-	-	-
214	8310	Structures and Improvements	3.0	Peak Day	0	-	-	-	-	-
215	8320	Reservoirs & Wells Maintenance	3.0	Peak Day	0	-	-	-	-	-
216	8330	Line Maintenance	3.0	Peak Day	0	-	-	-	-	-
217	8340	Compressor Station Equip Maint	3.0	Peak Day	23,208	12,531	7,734	-	2,943	-
218	8350	Meas. & Regul. Station Equip Maint	3.0	Peak Day	0	-	-	-	-	-
219	8360	Purification Equipment Maintenance	3.0	Peak Day	0	-	-	-	-	-
220	8410	Other storage expenses-Operation labor and expenses	3.0	Peak Day	116,621	62,970	38,862	-	14,790	-
221		Total Underground Storage Expense			243,169	131,300	81,031	0	30,838	0
222										
223		Transmission:								
224		Operation								
225	8500	Op., Sup., & Eng.	3.0	Peak Day	0	-	-	-	-	-
226	8510	System Control & Load Dispatching	3.0	Peak Day	0	-	-	-	-	-
227	8520	Communication Systems Expense	3.0	Peak Day	0	-	-	-	-	-
228	8530	Compressor Station Labor Expense	3.0	Peak Day	0	-	-	-	-	-
229	8540	Compressor Station Fuel Gas	3.0	Peak Day	0	-	-	-	-	-
230	8550	Compressor Station Fuel & Power	3.0	Peak Day	488	264	163	-	62	-
231	8560	Mains Expense	3.0	Peak Day	145,499	78,563	48,484	-	18,452	-
232	8570	Meas. & Regul. Station Expenses	3.0	Peak Day	11,936	6,445	3,977	-	1,514	-
233	8580	LDC Payment	3.0	Peak Day	0	-	-	-	-	-
234	8580	LDC Payment - A&G	3.0	Peak Day	0	-	-	-	-	-
235	8590	Other Expenses	3.0	Peak Day	0	-	-	-	-	-
236	8600	Rents	3.0	Peak Day	0	-	-	-	-	-
237		Maintenance								
238	8610	Maint. Sup., & Eng.	3.0	Peak Day	0	-	-	-	-	-
239	8620	Structures and Improvements	3.0	Peak Day	0	-	-	-	-	-
240	8630	Mains	3.0	Peak Day	22,915	12,373	7,636	-	2,906	-
241	8640	Compressor Station Equip Maint	3.0	Peak Day	0	-	-	-	-	-
242	8650	Meas. & Regul. Station Equip Maint	3.0	Peak Day	0	-	-	-	-	-
243	8660	Communication Equipment Maintenance	3.0	Peak Day	0	-	-	-	-	-
244	8670	Other Equipment Maintenance	3.0	Peak Day	0	-	-	-	-	-
245		Total Transmission Expense			180,838	97,644	60,261	0	22,934	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF O&M EXPENSES										
246										
247		Distribution:								
248		Operation								
249	8700	Supervision and Engineering	10.4	Composite of Accts. 871-879 & 886-893 - Demand	762,477	411,702	254,079	-	96,696	-
250	8710	Distribution Load Dispatching	99.0	-	0	-	-	-	-	-
251	8711	Odorization	99.0	-	0	-	-	-	-	-
251	8720	Compressor Station Labor & Expenses	11.4	Composite of Accts. 376 & 380 - Demand	0	-	-	-	-	-
252	8740	Mains & Services	12.4	Composite of Accts. 374-379 - Demand	2,776,514	1,499,188	925,214	-	352,112	-
253	8750	Measuring and Regulating Station Exp. - Gen	12.4	Composite of Accts. 374-379 - Demand	555,686	300,044	185,170	-	70,471	-
254	8760	Measuring and Regulating Station Exp. - Ind.	99.0	-	0	-	-	-	-	-
255	8770	Measuring and Regulating Sta. Exp. - City Gate	12.4	Composite of Accts. 374-379 - Demand	2,240	1,209	746	-	284	-
256	8780	Meters and House Regulator Expense	13.4	Composite of Accts. 381-383 - Demand	0	-	-	-	-	-
257	8790	Customer Installations Expense	99.0	-	0	-	-	-	-	-
258	8800	Other Expense	10.4	Composite of Accts. 871-879 & 886-893 - Demand	1,099	593	366	-	139	-
259	8810	Rents	10.4	Composite of Accts. 871-879 & 886-893 - Demand	26,722	14,428	8,904	-	3,389	-
260		Maintenance								
261	8850	Maintenance Supervision and Engineering	10.4	Composite of Accts. 871-879 & 886-893 - Demand	0	-	-	-	-	-
262	8860	Maintenance of Structures and Improvements	12.4	Composite of Accts. 374-379 - Demand	0	-	-	-	-	-
263	8870	Maintenance of Mains	12.4	Composite of Accts. 374-379 - Demand	58,967	31,839	19,649	-	7,478	-
264	8890	Maintenance of compressor station equipment	99.0	-	0	-	-	-	-	-
265	8900	Maint. of Measuring and Regulating Station Equip. - General	12.4	Composite of Accts. 374-379 - Demand	0	-	-	-	-	-
266	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	99.0	-	0	-	-	-	-	-
267	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	12.4	Composite of Accts. 374-379 - Demand	73	39	24	-	9	-
268	8930	Maintenance of Services	14.4	Account 380 - Demand	0	-	-	-	-	-
269	8940	Maintenance of Meters and House Regulators	13.4	Composite of Accts. 381-383 - Demand	0	-	-	-	-	-
270	8950	Maintenance of Other Equipment	10.4	Composite of Accts. 871-879 & 886-893 - Demand	0	-	-	-	-	-
271		Total Distribution			4,183,777	2,259,044	1,394,154	0	530,579	0
272										
273		Customer Accounts:								
274	9010	Supervision	99.0	-	0	-	-	-	-	-
275	9020	Meter Reading Expense	99.0	-	0	-	-	-	-	-
276	9030	Customer Records and Collection Expenses	99.0	-	0	-	-	-	-	-
277	9040	Uncollectible Accounts	99.0	-	0	-	-	-	-	-
278	9050	Miscellaneous Customer Accounts Expenses	99.0	-	0	-	-	-	-	-
279		Total Customer Accounts			0	-	-	-	-	-
280										
281		Customer Service and Information:								
282	9070	Supervision	99.0	-	0	-	-	-	-	-
283	9080	Customer Assistance Expenses	99.0	-	0	-	-	-	-	-
284	9090	Informational and Instructional Advertising Expenses	99.0	-	0	-	-	-	-	-
285	9100	Miscellaneous Customer Service and Informational Expenses	99.0	-	0	-	-	-	-	-
286		Total Customer Service and Information			0	-	-	-	-	-
287										
288		Sales:								
289	9110	Supervision	99.0	-	0	-	-	-	-	-
290	9120	Demonstrating and Selling Expenses	99.0	-	0	-	-	-	-	-
291	9130	Advertising Expenses	99.0	-	0	-	-	-	-	-
292	9160	Miscellaneous Sales Expenses	99.0	-	0	-	-	-	-	-
293		Total Sales			0	-	-	-	-	-
294										
295		Administrative & General:								
296		Operation								
297	9200	Administrative and General Salaries	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	0	-	-	-	-	-
298	9210	Office Supplies and Expenses	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	22,323	12,053	7,439	-	2,831	-
299	9220	Administrative Expenses Transferred - Customer Support	99.0	-	0	-	-	-	-	-
300	9220	Administrative Expenses Transferred - General	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	5,898,711	3,185,029	1,965,619	-	748,064	-
301	9230	Outside Services Employed	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	22,621	12,214	7,538	-	2,869	-
302	9240	Property Insurance	9.4	Allocated Net Plant - Demand	0	-	-	-	-	-
303	9250	Injuries and Damages	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	7,517	4,059	2,505	-	953	-
304	9260	Employee Pensions and Benefits	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	282,070	152,305	93,994	-	35,772	-
305	9270	Franchise Requirements	99.0	-	0	-	-	-	-	-
306	9280	Regulatory Commission Expenses	99.0	-	0	-	-	-	-	-
307	930.1	General Advertising Expenses	99.0	-	0	-	-	-	-	-
308	930.2	Miscellaneous General Expense	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	7,889	4,260	2,629	-	1,001	-
309	ADJ	Adjustments	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	(453,868)	(245,067)	(151,242)	-	(57,559)	-
310		Maintenance								
311	9320	Maintenance of General Plant	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	0	-	-	-	-	-
312		Total A&G			5,787,264	3,124,852	1,928,481	0	733,930	0
313										
314		TOTAL O&M EXPENSE - DEMAND			10,395,048	5,612,840	3,463,927	0	1,318,281	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
315		Production & Gathering:								
316		Operation								
317	7500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
318	7510	Production Maps & Records	99.0	-	0	-	-	-	-	-
319	7530	Field Lines Expenses	99.0	-	0	-	-	-	-	-
320	7540	Field Compressor Station Expense	99.0	-	0	-	-	-	-	-
321	7550	Field Compressor Sta. Fuel & Pwr.	99.0	-	0	-	-	-	-	-
322	7560	Field Meas. & Regul. Station Exp	18.4	Gas Costs	0	-	-	-	-	-
323	7570	Purification Expense	99.0	-	0	-	-	-	-	-
324	7590	Other Expenses	99.0	-	0	-	-	-	-	-
325		Maintenance								
326	7610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
327	7620	Structures and Improvements	99.0	-	0	-	-	-	-	-
328	7640	Field Line Maintenance	99.0	-	0	-	-	-	-	-
329	7650	Compressor Station Equip. Maint.	99.0	-	0	-	-	-	-	-
330	7660	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
331	7670	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
332	7680	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
333	7690	Gas Processed By Others	99.0	-	0	-	-	-	-	-
334		Total Production & Gathering			0	0	0	0	0	0
335										
336		Other Gas Supply Expenses:								
337		Operation								
338	8001	Intercompany Gas Well-head Purchases	18.4	Gas Costs	0	-	-	-	-	-
339	8010	Natural gas field line purchases	18.4	Gas Costs	115,617	66,622	47,883	1,112	-	-
340	8040	Natural gas city gate purchases	18.4	Gas Costs	50,226,537	28,941,994	20,801,358	483,186	-	-
341	8050	Transmission-Operation supervision and engineering	18.4	Gas Costs	(29,531)	(17,016)	(12,230)	(284)	-	-
342	8051	Other Gas Purchases / Gas Cost Adjustments	18.4	Gas Costs	53,391,020	30,765,461	22,111,930	513,629	-	-
343	8052	PGA for Commercial	18.4	Gas Costs	30,150,016	17,373,318	12,486,652	290,047	-	-
344	8053	PGA for Industrial	18.4	Gas Costs	4,872,096	2,807,444	2,017,782	46,870	-	-
345	8054	PGA for Public Authority	18.4	Gas Costs	4,999,866	2,881,068	2,070,698	48,099	-	-
346	8058	Unbilled PGA Cost	18.4	Gas Costs	(5,763,929)	(3,321,344)	(2,387,135)	(55,450)	-	-
347	8059	PGA Offset to Unrecovered Gas Cost	18.4	Gas Costs	(109,657,357)	(63,187,763)	(45,414,676)	(1,054,918)	-	-
348	8060	Exchange gas	18.4	Gas Costs	(122,035)	(70,320)	(50,541)	(1,174)	-	-
349	8081	Gas withdrawn from storage-Debit	18.4	Gas Costs	30,798,939	17,747,246	12,755,403	296,290	-	-
350	8082	Gas delivered to storage-Credit	18.4	Gas Costs	(14,414,625)	(8,306,127)	(5,969,828)	(138,671)	-	-
351	8120	Gas used for other utility operations-Credit	18.4	Gas Costs	(8,172)	(4,709)	(3,384)	(79)	-	-
352	8580	Transmission and compression of gas by others	18.4	Gas Costs	43,082,454	24,825,365	17,842,630	414,459	-	-
353		Maintenance								
354	8350	Maint. Of Purch. Gas Meas. Sta.	18.4	Gas Costs	0	-	-	-	-	-
355		Total Other Gas Supply Expenses			87,640,898	50,501,238	36,296,543	843,117	0	0
356										
357		Underground Storage:								
358		Operation								
359	8140	Storage-Operation supervision and engineering	1.5	Winter Volumes	0	-	-	-	-	-
360	8160	Wells expenses	1.5	Winter Volumes	17,582	6,679	4,408	95	3,131	3,268
361	8170	Lines expenses	1.5	Winter Volumes	11,391	4,327	2,856	62	2,029	2,117
362	8180	Compressor station expenses	1.5	Winter Volumes	22,388	8,505	5,613	121	3,987	4,161
363	8190	Compressor station fuel and power	1.5	Winter Volumes	0	-	-	-	-	-
364	8200	Storage-Measuring and regulating station expenses	1.5	Winter Volumes	4,768	1,811	1,195	26	849	886
365	8210	Storage-Purification expenses	1.5	Winter Volumes	41,970	15,945	10,523	227	7,475	7,801
366	8240	Storage-Other expenses	1.5	Winter Volumes	0	-	-	-	-	-
367	8250	Storage well royalties	1.5	Winter Volumes	5,241	1,991	1,314	28	933	974
368	8260	Rents	1.5	Winter Volumes	0	-	-	-	-	-
369		Maintenance								
370	8300	Maint. Sup., & Eng.	1.5	Winter Volumes	0	-	-	-	-	-
371	8310	Structures and Improvements	1.5	Winter Volumes	0	-	-	-	-	-
372	8320	Reservoirs & Wells Maintenance	1.5	Winter Volumes	0	-	-	-	-	-
373	8330	Line Maintenance	1.5	Winter Volumes	0	-	-	-	-	-
374	8340	Compressor Station Equip Maint	1.5	Winter Volumes	23,208	8,817	5,819	125	4,133	4,314
375	8350	Meas. & Regul. Station Equip Maint	1.5	Winter Volumes	0	-	-	-	-	-
376	8360	Purification Equipment Maintenance	1.5	Winter Volumes	0	-	-	-	-	-
377	8410	Other storage expenses-Operation labor and expenses	1.5	Winter Volumes	116,621	44,305	29,240	630	20,769	21,677
378		Total Underground Storage Expense			243,169	92,381	60,969	1,314	43,307	45,199
379										
380		Transmission:								
381		Operation								
382	8500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
383	8510	System Control & Load Dispatching	99.0	-	0	-	-	-	-	-
384	8520	Communication Systems Expense	99.0	-	0	-	-	-	-	-
385	8530	Compressor Station Labor Expense	99.0	-	0	-	-	-	-	-
386	8540	Compressor Station Fuel Gas	99.0	-	0	-	-	-	-	-
387	8550	Compressor Station Fuel & Power	99.0	-	0	-	-	-	-	-
388	8560	Mains Expense	99.0	-	0	-	-	-	-	-
389	8570	Meas. & Regul. Station Expenses	99.0	-	0	-	-	-	-	-
390	8580	LDC Payment	99.0	-	0	-	-	-	-	-
391	8580	LDC Payment - A&G	99.0	-	0	-	-	-	-	-
392	8590	Other Expenses	99.0	-	0	-	-	-	-	-
393	8600	Rents	99.0	-	0	-	-	-	-	-
394		Maintenance								
395	8610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
396	8620	Structures and Improvements	99.0	-	0	-	-	-	-	-
397	8630	Mains	99.0	-	0	-	-	-	-	-
398	8640	Compressor Station Equip Maint	99.0	-	0	-	-	-	-	-
399	8650	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
400	8660	Communication Equipment Maintenance	99.0	-	0	-	-	-	-	-
401	8670	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
402		Total Transmission Expense			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF O&M EXPENSES										
403										
404		Distribution:								
405		Operation								
406	8700	Supervision and Engineering	10.6	Composite of Accts. 871-879 & 886-893 - Comm	61,423	18,051	12,972	386	14,367	15,646
407	8710	Distribution Load Dispatching	1.0	Mcf	(41)	(12)	(9)	(0)	(10)	(11)
408	8711	Odorization	1.0	Mcf	132,819	39,034	28,051	835	31,067	33,833
408	8720	Compressor Station Labor & Expenses	99.0	-	0	-	-	-	-	-
409	8740	Mains & Services	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
410	8750	Measuring and Regulating Station Exp. - Gen	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
411	8760	Measuring and Regulating Station Exp. - Ind.	99.0	-	0	-	-	-	-	-
412	8770	Measuring and Regulating Sta. Exp. - City Gate	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
413	8780	Meters and House Regulator Expense	99.0	-	0	-	-	-	-	-
414	8790	Customer Installations Expense	99.0	-	0	-	-	-	-	-
415	8800	Other Expense	10.6	Composite of Accts. 871-879 & 886-893 - Comm	89	26	19	1	21	23
416	8810	Rents	10.6	Composite of Accts. 871-879 & 886-893 - Comm	2,153	633	455	14	503	548
417		Maintenance								
418	8850	Maintenance Supervision and Engineering	10.6	Composite of Accts. 871-879 & 886-893 - Comm	0	-	-	-	-	-
419	8860	Maintenance of Structures and Improvements	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
420	8870	Maintenance of Mains	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
421	8890	Maintenance of compressor station equipment	1.0	Mcf	140,590	41,317	29,692	884	32,884	35,812
422	8900	Maint. of Measuring and Regulating Station Equip. - General	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
423	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	5.0	Direct to Transport Interruptible	0	-	-	-	-	-
424	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
425	8930	Maintenance of Services	14.6	Account 380 - Comm	0	-	-	-	-	-
426	8940	Maintenance of Meters and House Regulators	13.6	Composite of Accts. 381-383 - Comm	0	-	-	-	-	-
427	8950	Maintenance of Other Equipment	10.6	Composite of Accts. 871-879 & 886-893 - Comm	0	-	-	-	-	-
428		Total Distribution			337,032	99,048	71,179	2,120	78,832	85,852
429										
430		Customer Accounts:								
431	9010	Supervision	99.0	-	0	-	-	-	-	-
432	9020	Meter Reading Expense	99.0	-	0	-	-	-	-	-
433	9030	Customer Records and Collection Expenses	99.0	-	0	-	-	-	-	-
434	9040	Uncollectible Accounts	99.0	-	0	-	-	-	-	-
435	9050	Miscellaneous Customer Accounts Expenses	99.0	-	0	-	-	-	-	-
436		Total Customer Accounts			0	-	-	-	-	-
437										
438		Customer Service and Information:								
439	9070	Supervision	99.0	-	0	-	-	-	-	-
440	9080	Customer Assistance Expenses	99.0	-	0	-	-	-	-	-
441	9090	Informational and Instructional Advertising Expenses	99.0	-	0	-	-	-	-	-
442	9100	Miscellaneous Customer Service and Informational Expenses	99.0	-	0	-	-	-	-	-
443		Total Customer Service and Information			0	-	-	-	-	-
444										
445		Sales:								
446	9110	Supervision	99.0	-	0	-	-	-	-	-
447	9120	Demonstrating and Selling Expenses	99.0	-	0	-	-	-	-	-
448	9130	Advertising Expenses	99.0	-	0	-	-	-	-	-
449	9160	Miscellaneous Sales Expenses	99.0	-	0	-	-	-	-	-
450		Total Sales			0	-	-	-	-	-
451										
452		Administrative & General:								
453		Operation								
454	9200	Administrative and General Salaries	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	0	-	-	-	-	-
455	9210	Office Supplies and Expenses	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	1,798	528	380	11	421	458
456	9220	Administrative Expenses Transferred - Customer Support	99.0	-	0	-	-	-	-	-
457	9220	Administrative Expenses Transferred - General	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	475,181	139,648	100,356	2,989	111,145	121,043
458	9230	Outside Services Employed	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	1,822	536	385	11	426	464
459	9240	Property Insurance	9.6	Allocated Net Plant - Comm	0	-	-	-	-	-
460	9250	Injuries and Damages	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	606	178	128	4	142	154
461	9260	Employee Pensions and Benefits	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	22,723	6,678	4,799	143	5,315	5,788
462	9270	Franchise Requirements	99.0	-	0	-	-	-	-	-
463	9280	Regulatory Commission Expenses	99.0	-	0	-	-	-	-	-
464	930.1	General Advertising Expenses	99.0	-	0	-	-	-	-	-
465	930.2	Miscellaneous General Expense	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	636	187	134	4	149	162
466	ADJ	Adjustments	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	(36,562)	(10,745)	(7,722)	(230)	(8,552)	(9,313)
467		Maintenance								
468	9320	Maintenance of General Plant	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	0	-	-	-	-	-
469		Total A&G			466,203	137,010	98,460	2,932	109,045	118,756
470										
471		TOTAL O&M EXPENSE - COMMODITY			88,687,302	50,829,677	36,527,151	849,483	231,184	249,808

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

Total O&M Expenses

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
472		Production & Gathering:								
473		Operation								
474	7500	Op., Sup., & Eng.			0	0	0	0	0	0
475	7510	Production Maps & Records			0	0	0	0	0	0
476	7530	Field Lines Expenses			0	0	0	0	0	0
477	7540	Field Compressor Station Expense			0	0	0	0	0	0
478	7550	Field Compressor Sta. Fuel & Pwr.			0	0	0	0	0	0
479	7560	Field Meas. & Regul. Station Exp			0	0	0	0	0	0
480	7570	Purification Expense			0	0	0	0	0	0
481	7590	Other Expenses			0	0	0	0	0	0
482		Maintenance								
483	7610	Maint. Sup., & Eng.			0	0	0	0	0	0
484	7620	Structures and Improvements			0	0	0	0	0	0
485	7640	Field Line Maintenance			0	0	0	0	0	0
486	7650	Compressor Station Equip. Maint.			0	0	0	0	0	0
487	7660	Meas. & Regul. Station Equip Maint			0	0	0	0	0	0
488	7670	Purification Equipment Maintenance			0	0	0	0	0	0
489	7680	Other Equipment Maintenance			0	0	0	0	0	0
490	7690	Gas Processed By Others			0	0	0	0	0	0
491		Total Production & Gathering			0	0	0	0	0	0
492										
493		Other Gas Supply Expenses:								
494		Operation								
495	8001	Intercompany Gas Well-head Purchases			0	0	0	0	0	0
496	8010	Natural gas field line purchases			115,617	66,622	47,883	1,112	0	0
497	8040	Natural gas city gate purchases			50,226,537	28,941,994	20,801,358	483,186	0	0
498	8050	Transmission-Operation supervision and engineering			(29,531)	(17,016)	(12,230)	(284)	0	0
499	8051	Other Gas Purchases / Gas Cost Adjustments			53,391,020	30,765,461	22,111,930	513,629	0	0
500	8052	PGA for Commercial			30,150,016	17,373,318	12,486,652	290,047	0	0
501	8053	PGA for Industrial			4,872,096	2,807,444	2,017,782	46,870	0	0
502	8054	PGA for Public Authority			4,999,866	2,881,068	2,070,698	48,099	0	0
503	8058	Unbilled PGA Cost			(5,763,929)	(3,321,344)	(2,387,135)	(55,450)	0	0
504	8059	PGA Offset to Unrecovered Gas Cost			(109,657,357)	(63,187,763)	(45,414,676)	(1,054,918)	0	0
505	8060	Exchange gas			(122,035)	(70,320)	(50,541)	(1,174)	0	0
506	8081	Gas withdrawn from storage-Debit			30,798,939	17,747,246	12,755,403	296,290	0	0
507	8082	Gas delivered to storage-Credit			(14,414,625)	(8,306,127)	(5,969,828)	(138,671)	0	0
508	8120	Gas used for other utility operations-Credit			(8,172)	(4,709)	(3,384)	(79)	0	0
509	8580	Transmission and compression of gas by others			43,082,454	24,825,365	17,842,630	414,459	0	0
510		Maintenance								
511	8350	Maint. Of Purch. Gas Meas. Sta.			0	0	0	0	0	0
512		Total Other Gas Supply Expenses			87,640,898	50,501,238	36,296,543	843,117	0	0
513										
514		Underground Storage:								
515		Operation								
516	8140	Storage-Operation supervision and engineering			0	0	0	0	0	0
517	8160	Wells expenses			35,164	16,173	10,267	95	5,361	3,268
518	8170	Lines expenses			22,782	10,478	6,652	62	3,473	2,117
519	8180	Compressor station expenses			44,776	20,594	13,074	121	6,826	4,161
520	8190	Compressor station fuel and power			0	0	0	0	0	0
521	8200	Storage-Measuring and regulating station expenses			9,536	4,386	2,784	26	1,454	886
522	8210	Storage-Purification expenses			83,940	38,606	24,509	227	12,797	7,801
523	8240	Storage-Other expenses			0	0	0	0	0	0
524	8250	Storage well royalties			10,482	4,821	3,060	28	1,598	974
525	8260	Rents			0	0	0	0	0	0
526		Maintenance								
527	8300	Maint. Sup., & Eng.			0	0	0	0	0	0
528	8310	Structures and Improvements			0	0	0	0	0	0
529	8320	Reservoirs & Wells Maintenance			0	0	0	0	0	0
530	8330	Line Maintenance			0	0	0	0	0	0
531	8340	Compressor Station Equip Maint			46,416	21,348	13,552	125	7,076	4,314
532	8350	Meas. & Regul. Station Equip Maint			0	0	0	0	0	0
533	8360	Purification Equipment Maintenance			0	0	0	0	0	0
534	8410	Other storage expenses-Operation labor and expenses			233,243	107,275	68,102	630	35,559	21,677
535		Total Underground Storage Expense			486,338	223,681	142,000	1,314	74,145	45,199
536										
537		Transmission:								
538		Operation								
539	8500	Op., Sup., & Eng.			0	0	0	0	0	0
540	8510	System Control & Load Dispatching			0	0	0	0	0	0
541	8520	Communication Systems Expense			0	0	0	0	0	0
542	8530	Compressor Station Labor Expense			0	0	0	0	0	0
543	8540	Compressor Station Fuel Gas			0	0	0	0	0	0
544	8550	Compressor Station Fuel & Power			488	264	163	0	62	0
545	8560	Mains Expense			145,499	78,563	48,484	0	18,452	0
546	8570	Meas. & Regul. Station Expenses			11,936	6,445	3,977	0	1,514	0
547	8580	LDC Payment			0	0	0	0	0	0
548	8580	LDC Payment - A&G			0	0	0	0	0	0
549	8590	Other Expenses			0	0	0	0	0	0
550	8600	Rents			0	0	0	0	0	0
551		Maintenance								
552	8610	Maint. Sup., & Eng.			0	0	0	0	0	0
553	8620	Structures and Improvements			0	0	0	0	0	0
554	8630	Mains			22,915	12,373	7,636	0	2,906	0
555	8640	Compressor Station Equip Maint			0	0	0	0	0	0
556	8650	Meas. & Regul. Station Equip Maint			0	0	0	0	0	0
557	8660	Communication Equipment Maintenance			0	0	0	0	0	0
558	8670	Other Equipment Maintenance			0	0	0	0	0	0
559		Total Transmission Expense			180,838	97,644	60,261	0	22,934	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

560									
561		Distribution:							
562		Operation							
563	8700	Supervision and Engineering		2,140,705	1,558,134	450,099	624	114,270	17,577
564	8710	Distribution Load Dispatching		(41)	(12)	(9)	(0)	(10)	(11)
565	8711	Odorization		132,819	39,034	28,051	835	31,067	33,833
565	8720	Compressor Station Labor & Expenses		0	0	0	0	0	0
566	8740	Mains & Services		6,802,984	5,073,315	1,373,154	195	354,739	1,581
567	8750	Measuring and Regulating Station Exp. - Gen		1,361,535	1,015,363	274,820	39	70,997	317
568	8760	Measuring and Regulating Station Exp. - Ind.		523	0	518	0	3	2
569	8770	Measuring and Regulating Sta. Exp. - City Gate		5,487	4,092	1,108	0	286	1
570	8780	Meters and House Regulator Expense		938,471	653,413	266,517	821	11,060	6,659
571	8790	Customer Installations Expense		257	228	29	0	0	0
572	8800	Other Expense		3,085	2,246	649	1	165	25
573	8810	Rents		75,023	54,606	15,774	22	4,005	616
574		Maintenance							
575	8850	Maintenance Supervision and Engineering		0	0	0	0	0	0
576	8860	Maintenance of Structures and Improvements		0	0	0	0	0	0
577	8870	Maintenance of Mains		144,480	107,746	29,163	4	7,534	34
578	8890	Maintenance of compressor station equipment		140,590	41,317	29,692	884	32,884	35,812
579	8900	Maint. of Measuring and Regulating Station Equip. - General		0	0	0	0	0	0
580	8910	Maint. of Measuring and Regulating Station Equip. - Industrial		135	0	133	0	1	0
581	8920	Maint. of Measuring and Regulating Station Equip. - City Gate		178	133	36	0	9	0
582	8930	Maintenance of Services		0	0	0	0	0	0
583	8940	Maintenance of Meters and House Regulators		0	0	0	0	0	0
584	8950	Maintenance of Other Equipment		0	0	0	0	0	0
585		Total Distribution		11,746,231	8,549,614	2,469,734	3,426	627,010	96,448
586									
587		Customer Accounts:							
588	9010	Supervision		0	0	0	0	0	0
589	9020	Meter Reading Expense		735,288	652,684	81,800	36	480	289
590	9030	Customer Records and Collection Expenses		1,067,803	947,844	118,792	52	697	419
591	9040	Uncollectible Accounts		731,532	496,144	235,187	0	200	0
592	9050	Miscellaneous Customer Accounts Expenses		0	0	0	0	0	0
593		Total Customer Accounts		2,534,624	2,096,673	435,779	87	1,376	708
594									
595		Customer Service and Information:							
596	9070	Supervision		0	0	0	0	0	0
597	9080	Customer Assistance Expenses		0	0	0	0	0	0
598	9090	Informational and Instructional Advertising Expenses		214,461	190,368	23,859	10	140	84
599	9100	Miscellaneous Customer Service and Informational Expenses		0	0	0	0	0	0
600		Total Customer Service and Information		214,461	190,368	23,859	10	140	84
601									
602		Sales:							
603	9110	Supervision		158,549	140,737	17,638	8	103	62
604	9120	Demonstrating and Selling Expenses		77,078	68,419	8,575	4	50	30
605	9130	Advertising Expenses		36,821	32,685	4,096	2	24	14
606	9160	Miscellaneous Sales Expenses		(188,721)	(167,520)	(20,995)	(9)	(123)	(74)
607		Total Sales		83,728	74,321	9,315	4	55	33
608									
609		Administrative & General:							
610		Operation							
611	9200	Administrative and General Salaries		0	0	0	0	0	0
612	9210	Office Supplies and Expenses		69,069	51,295	13,889	19	3,350	517
613	9220	Administrative Expenses Transferred - Customer Support		0	0	0	0	0	0
614	9220	Administrative Expenses Transferred - General		18,251,309	13,554,504	3,670,122	4,912	885,125	136,646
615	9230	Outside Services Employed		69,993	51,981	14,075	19	3,394	524
616	9240	Property Insurance		0	0	0	0	0	0
617	9250	Injuries and Damages		23,257	17,272	4,677	6	1,128	174
618	9260	Employee Pensions and Benefits		872,759	648,162	175,501	235	42,326	6,534
619	9270	Franchise Requirements		635	564	71	0	0	0
620	9280	Regulatory Commission Expenses		165,392	146,811	18,400	8	108	65
621	930.1	General Advertising Expenses		0	0	0	0	0	0
622	930.2	Miscellaneous General Expense		24,411	18,129	4,909	7	1,184	183
623	ADJ	Adjustments		(1,404,321)	(1,042,932)	(282,392)	(378)	(68,105)	(10,514)
624		Maintenance							
625	9320	Maintenance of General Plant		0	0	0	0	0	0
626		Total A&G		18,072,504	13,445,787	3,619,251	4,827	868,510	134,129
627									
628		TOTAL O&M EXPENSE		120,959,622	75,179,326	43,056,740	852,785	1,594,170	276,602

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Intangible Plant:								
2										
3	30100	Organization	99.0	-	0	-	-	-	-	-
4	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
5	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
6										
7		Total Intangible Plant:			0	-	-	-	-	-
8										
9		Production Plant:								
10			99.0	-	0	-	-	-	-	-
11	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
12	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
13	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
14	33201	Field Lines	99.0	-	0	-	-	-	-	-
15	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
17	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
18										
19		Total Production Plant			0	-	-	-	-	-
20										
21		Storage Plant:								
22										
23	35010	Land	99.0	-	0	-	-	-	-	-
24	35020	Rights of Way	99.0	-	0	-	-	-	-	-
25	35100	Structures and Improvements	99.0	-	0	-	-	-	-	-
26	35102	Compression Station Equipment	99.0	-	0	-	-	-	-	-
27	35103	Meas. & Reg. Sta. Structues	99.0	-	0	-	-	-	-	-
28	35104	Other Structures	99.0	-	0	-	-	-	-	-
29	35200	Wells \ Rights of Way	99.0	-	0	-	-	-	-	-
30	35201	Well Construction	99.0	-	0	-	-	-	-	-
31	35202	Well Equipment	99.0	-	0	-	-	-	-	-
32	35203	Cushion Gas	99.0	-	0	-	-	-	-	-
33	35210	Leaseholds	99.0	-	0	-	-	-	-	-
34	35211	Storage Rights	99.0	-	0	-	-	-	-	-
35	35301	Field Lines	99.0	-	0	-	-	-	-	-
36	35302	Tributary Lines	99.0	-	0	-	-	-	-	-
37	35400	Compressor Station Equipment	99.0	-	0	-	-	-	-	-
38	35500	Meas & Reg. Equipment	99.0	-	0	-	-	-	-	-
39	35600	Purification Equipment	99.0	-	0	-	-	-	-	-
40										
41		Total Storage Plant			0	-	-	-	-	-
42										
43		Transmission:								
44										
45	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
46	36520	Rights of Way	99.0	-	0	-	-	-	-	-
47	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
48	36603	Other Structues	99.0	-	0	-	-	-	-	-
49	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
50	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
51	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
52	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
53	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
54										
55		Total Transmission Plant			0	-	-	-	-	-
56										
57		Distribution:								
58										
59	37400	Land & Land Rights	2.0	Bills	0	-	-	-	-	-
60	37401	Land	2.0	Bills	0	-	-	-	-	-
61	37402	Land Rights	2.0	Bills	32,235	28,614	3,586	2	21	13
62	37403	Land Other	2.0	Bills	0	-	-	-	-	-
63	37500	Structures & Improvements	2.0	Bills	2,865	2,543	319	0	2	1
64	37501	Structures & Improvements T.B.	2.0	Bills	851	755	95	0	1	0
65	37502	Land Rights	2.0	Bills	394	350	44	0	0	0
66	37503	Improvements	2.0	Bills	34	30	4	0	0	0
67	37600	Mains Cathodic Protection	2.0	Bills	94,280	83,688	10,489	5	62	37
68	37601	Mains - Steel	2.0	Bills	2,103,622	1,867,296	234,026	102	1,372	826
69	37602	Mains - Plastic	2.0	Bills	2,022,033	1,794,873	224,949	98	1,319	794
70	37603	Mains - Anodes	2.0	Bills	118,800	105,453	13,216	6	78	47
71	37604	Mains - Leak Clamps	2.0	Bills	200,936	178,362	22,354	10	131	79
72	37800	Meas & Reg. Sta. Equip - General	2.0	Bills	339,500	301,360	37,769	16	221	133
73	37900	Meas & Reg. Sta. Equip - City Gate	2.0	Bills	127,095	112,817	14,139	6	83	50
74	37905	Meas & Reg. Sta. Equipment T.b.	2.0	Bills	22,069	19,590	2,455	1	14	9
75	38000	Services	2.0	Bills	4,814,131	4,273,300	535,566	233	3,141	1,891
76	38100	Meters	4.0	Meter Investment	2,722,922	1,895,843	773,286	2,381	32,091	19,321
77	38200	Meter Installaitons	4.0	Meter Investment	2,026,363	1,410,862	575,469	1,772	23,882	14,378
78	38300	House Regulators	4.0	Meter Investment	124,799	86,892	35,442	109	1,471	886
79	38400	House Reg. Installations	4.0	Meter Investment	12,401	8,635	3,522	11	146	88
80	38500	Ind. Meas. & Reg. Sta. Equipment	2.2	Non-Residential Bills	97,340	-	96,392	42	565	340
81	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
82										
83		Total Distribution Plant			14,862,670	12,171,264	2,583,121	4,793	64,600	38,893

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Customer/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
84											
85		General:									
86											
87	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
88	39000	Structures Frame	6.2	P, S, T & D Plant - Customer	155,570	130,989	23,830	33	448	270
89	39001	Structures & Improvements	6.2	P, S, T & D Plant - Customer	2,906	2,447	445	1	8	5
90	39002	Improvements	6.2	P, S, T & D Plant - Customer	14,717	12,391	2,254	3	42	26
91	39003	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	382	322	59	0	1	1
92	39004	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
93	39009	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	62,762	52,845	9,614	13	181	109
94	39100	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
95	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
96	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	1,735	1,461	266	0	5	3
97	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
98	39202	Trailers	6.2	P, S, T & D Plant - Customer	351	296	54	0	1	1
99	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
100	39500	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	117,004	98,516	17,923	25	337	203
101	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
102	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
103	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
104	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
105	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	19,996	16,836	3,063	4	58	35
106	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
107	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
108	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
109	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	137,742	115,978	21,099	29	397	239
110	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
111	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
112	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
113	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
114	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
115	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
116	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	7,638	6,431	1,170	2	22	13
117	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
118	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
119	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
120	40600	Amortization of gas plant acquisition adjustments	6.2	P, S, T & D Plant - Customer	34,062	28,680	5,218	7	98	59
121										
122										
123		Total General Plant			554,865	467,191	84,994	119	1,599	963
124										
125		TOTAL DIRECT DEPRECIATION EXPENSE			15,417,535	12,638,455	2,668,115	4,912	66,199	39,855
126										
127		Kentucky Mid-States General Office:								
128										
129		Intangible Plant:								
130										
131	30100	Organization	99.0	-	0	-	-	-	-	-
132	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
133	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
134										
135		Total Intangible Plant:			0	-	-	-	-	-
136										
137		General:								
138										
139	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
140	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	2,724	2,294	417	1	8	5
141	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
142	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
143	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	108	91	17	0	0	0
144	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
145	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	598	503	92	0	2	1
146	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
147	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
148	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	43	36	7	0	0	0
149	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
150	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
151	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
152	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	967	815	148	0	3	2
153	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	7	6	1	0	0	0
154	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
155	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
156	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
157	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
158	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
159	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
160	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
161	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
162	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
163	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
164	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
165	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	1,072	903	164	0	3	2
166	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
167	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
168	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
169	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
170	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
171	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
172	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
173										
174										
175		Total General Plant			5,519	4,647	845	1	16	10

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF DEPRECIATION EXPENSE										
176										
177		Shared Services General Office:								
178										
179		General:								
180										
181	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
182	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	7,937	6,683	1,216	2	23	14
183	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
184	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
185	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
186	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	19,832	16,698	3,038	4	57	34
187	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	16,995	14,310	2,603	4	49	29
188	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
189	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
190	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	655	552	100	0	2	1
191	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
192	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
193	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
194	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	118	99	18	0	0	0
195	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
196	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
197	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
198	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
199	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	1,549	1,304	237	0	4	3
200	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
201	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
202	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
203	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	267	225	41	0	1	0
204	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
205	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	232,796	196,012	35,660	50	671	404
206	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	152,793	128,650	23,405	33	440	265
207	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	22,912	19,292	3,510	5	66	40
208	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
209	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
210	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	29,579	24,905	4,531	6	85	51
211	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	304	256	47	0	1	1
212	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
213	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	352,898	297,137	54,057	75	1,017	612
214	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
215	ADJ	WTW Adjustment	6.2	P, S, T & D Plant - Customer	(5,849)	(4,925)	(896)	(1)	(17)	(10)
216										
217		Total General Plant			832,785	701,197	127,566	178	2,400	1,445
218										
219		Shared Services Customer Support:								
220										
221		General:								
222										
223	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
224	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
225	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	18,219	15,340	2,791	4	52	32
226	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
227	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
228	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	5,231	4,405	801	1	15	9
229	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	7,763	6,537	1,189	2	22	13
230	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
231	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
232	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
233	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
234	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
235	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
236	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	1,830	1,541	280	0	5	3
237	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
238	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
239	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
240	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
241	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	4,639	3,906	711	1	13	8
242	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
243	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
244	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
245	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	1,451	1,222	222	0	4	3
246	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	819	690	125	0	2	1
247	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	26,644	22,434	4,081	6	77	46
248	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
249	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	2,770	2,332	424	1	8	5
250	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
251	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
252	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	12,902	10,863	1,976	3	37	22
253	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	8	7	1	0	0	0
254	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
255	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	277,939	234,022	42,575	59	801	482
256	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
257										
258										
259		Total General Plant			360,216	303,299	55,178	77	1,038	625
260										
261	NTB	To Match Schedule C-1	6.2	P, S, T & D Plant - Customer	133	112	20	0	0	0
262										
263		TOTAL DEPRECIATION EXPENSE - CUSTOMER			16,616,188	13,647,709	2,851,724	5,168	69,652	41,935

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
264		Intangible Plant:								
265										
266	30100	Organization	99.0	-	0	-	-	-	-	-
267	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
268	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
269										
270		Total Intangible Plant:			0	-	-	-	-	-
271										
272		Production Plant:								
273			3.0	Peak Day	0	-	-	-	-	-
274	32520	Producing Leaseholds	3.0	Peak Day	0	-	-	-	-	-
275	32540	Rights of Ways	3.0	Peak Day	0	-	-	-	-	-
276	33100	Production Gas Wells Equipment	3.0	Peak Day	0	-	-	-	-	-
277	33201	Field Lines	3.0	Peak Day	0	-	-	-	-	-
278	33202	Tributary Lines	3.0	Peak Day	0	-	-	-	-	-
279	33400	Field Meas. & Reg. Sta. Equip	3.0	Peak Day	0	-	-	-	-	-
280	33600	Purification Equipment	3.0	Peak Day	0	-	-	-	-	-
281										
282		Total Production Plant			0	-	-	-	-	-
283										
284		Storage Plant:								
285										
286	35010	Land	3.0	Peak Day	0	-	-	-	-	-
287	35020	Rights of Way	3.0	Peak Day	16	9	5	-	2	-
288	35100	Structures and Improvements	3.0	Peak Day	147	79	49	-	19	-
289	35102	Compression Station Equipment	3.0	Peak Day	1,531	827	510	-	194	-
290	35103	Meas. & Reg. Sta. Structues	3.0	Peak Day	127	69	42	-	16	-
291	35104	Other Structures	3.0	Peak Day	948	512	316	-	120	-
292	35200	Wells \ Rights of Way	3.0	Peak Day	120,988	65,328	40,317	-	15,344	-
293	35201	Well Construction	3.0	Peak Day	13,600	7,343	4,532	-	1,725	-
294	35202	Well Equipment	3.0	Peak Day	4,605	2,486	1,534	-	584	-
295	35203	Cushion Gas	3.0	Peak Day	11,864	6,406	3,953	-	1,505	-
296	35210	Leaseholds	3.0	Peak Day	500	270	167	-	63	-
297	35211	Storage Rights	3.0	Peak Day	279	150	93	-	35	-
298	35301	Field Lines	3.0	Peak Day	1,105	596	368	-	140	-
299	35302	Tributary Lines	3.0	Peak Day	1,319	712	439	-	167	-
300	35400	Compressor Station Equipment	3.0	Peak Day	154,463	83,403	51,472	-	19,589	-
301	35500	Meas & Reg. Equipment	3.0	Peak Day	2,553	1,379	851	-	324	-
302	35600	Purification Equipment	3.0	Peak Day	16,594	8,960	5,530	-	2,104	-
303										
304		Total Storage Plant			330,639	178,530	110,178	-	41,931	-
305										
306		Transmission:								
307										
308	36510	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
309	36520	Rights of Way	3.0	Peak Day	7,376	3,983	2,458	-	935	-
310	36602	Structures & Improvements	3.0	Peak Day	4,496	2,427	1,498	-	570	-
311	36603	Other Structues	3.0	Peak Day	0	-	-	-	-	-
312	36700	Mains Cathodic Protection	3.0	Peak Day	1,478	798	493	-	187	-
313	36701	Mains - Steel	3.0	Peak Day	384,012	207,348	127,964	-	48,700	-
314	36703	Mains - Anodes	3.0	Peak Day	0	-	-	-	-	-
315	36900	Meas. & Reg. Equipment	3.0	Peak Day	35,793	19,326	11,927	-	4,539	-
316	36901	Meas. & Reg. Equipment	3.0	Peak Day	40,624	21,935	13,537	-	5,152	-
317										
318		Total Transmission Plant			473,778	255,818	157,876	-	60,084	-
319										
320		Distribution:								
321										
322	37400	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
323	37401	Land	3.0	Peak Day	0	-	-	-	-	-
324	37402	Land Rights	3.0	Peak Day	22,228	12,002	7,407	-	2,819	-
325	37403	Land Other	3.0	Peak Day	0	-	-	-	-	-
326	37500	Structures & Improvements	3.0	Peak Day	1,976	1,067	658	-	251	-
327	37501	Structures & Improvements T.B.	3.0	Peak Day	587	317	195	-	74	-
328	37502	Land Rights	3.0	Peak Day	272	147	91	-	34	-
329	37503	Improvements	3.0	Peak Day	24	13	8	-	3	-
330	37600	Mains Cathodic Protection	3.0	Peak Day	65,012	35,104	21,664	-	8,245	-
331	37601	Mains - Steel	3.0	Peak Day	1,450,585	783,248	483,376	-	183,961	-
332	37602	Mains - Plastic	3.0	Peak Day	1,394,324	752,870	464,629	-	176,826	-
333	37603	Mains - Anodes	3.0	Peak Day	81,920	44,233	27,298	-	10,389	-
334	37604	Mains - Leak Clamps	3.0	Peak Day	138,558	74,815	46,172	-	17,572	-
335	37800	Meas & Reg. Sta. Equip - General	3.0	Peak Day	234,107	126,407	78,011	-	29,689	-
336	37900	Meas & Reg. Sta. Equip - City Gate	3.0	Peak Day	87,640	47,322	29,204	-	11,114	-
337	37905	Meas & Reg. Sta. Equipment T.b.	3.0	Peak Day	15,218	8,217	5,071	-	1,930	-
338	38000	Services	99.0	-	0	-	-	-	-	-
339	38100	Meters	99.0	-	0	-	-	-	-	-
340	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
341	38300	House Regulators	99.0	-	0	-	-	-	-	-
342	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
343	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
344	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
345										
346		Total Distribution Plant			3,492,451	1,885,761	1,163,784	-	442,906	-

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Customer/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
347											
348		General:									
349											
350	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
351	39000	Structures Frame	6.4	P, S, T & D Plant - Demand	64,926	35,057	21,635	-	8,234	-	
352	39001	Structures & Improvements	6.4	P, S, T & D Plant - Demand	1,213	655	404	-	154	-	
353	39002	Improvements	6.4	P, S, T & D Plant - Demand	6,142	3,316	2,047	-	779	-	
354	39003	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	159	86	53	-	20	-	
355	39004	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
356	39009	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	26,193	14,143	8,728	-	3,322	-	
357	39100	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
358	39102	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
359	39103	Transportation Equipment	6.4	P, S, T & D Plant - Demand	724	391	241	-	92	-	
360	39200	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
361	39201	Trailers	6.4	P, S, T & D Plant - Demand	147	79	49	-	19	-	
362	39202	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
363	39300	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	48,831	26,366	16,272	-	6,193	-	
364	39400	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
365	39600	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
366	39603	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
367	39604	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
368	39605	Communication Equipment	6.4	P, S, T & D Plant - Demand	8,345	4,506	2,781	-	1,058	-	
369	39700	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
370	39701	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
371	39702	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
372	39705	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	57,486	31,040	19,156	-	7,290	-	
373	39800	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
374	39900	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
375	39901	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
376	39902	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
377	39903	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
378	39904	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
379	39905	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	3,188	1,721	1,062	-	404	-	
380	39906	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
381	39907	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
382	39908	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
383	40600	Amortization of gas plant acquisition adjustments	6.4	P, S, T & D Plant - Demand	14,216	7,676	4,737	-	1,803	-	
384											
385											
386		Total General Plant			231,569	125,036	77,165	0	29,367	0	
387											
388		TOTAL DIRECT DEPRECIATION EXPENSE			4,528,437	2,445,145	1,509,005	0	574,288	0	
389											
390		Kentucky Mid-States General Office:									
391											
392		Intangible Plant:									
393											
394	30100	Organization	99.0	-	0	-	-	-	-	-	
395	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
396	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
397											
398		Total Intangible Plant:			0	-	-	-	-	-	
399											
400		General:									
401											
402	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
403	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	1,137	614	379	-	144	-	
404	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
405	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
406	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	45	24	15	-	6	-	
407	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
408	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	249	135	83	-	32	-	
409	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
410	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
411	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	18	10	6	-	2	-	
412	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
413	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
414	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
415	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	404	218	135	-	51	-	
416	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	3	2	1	-	0	-	
417	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
418	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
419	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
420	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
421	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
422	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
423	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
424	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
425	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
426	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
427	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
428	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	448	242	149	-	57	-	
429	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
430	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
431	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
432	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
433	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
434	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
435	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
436											
437											
438		Total General Plant			2,303	1,244	768	-	292	-	

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Customer/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
439											
440		Shared Services General Office:									
441											
442		General:									
443											
444	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
445	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	3,313	1,789	1,104	-	420	-	
446	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
447	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
448	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
449	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	8,277	4,469	2,758	-	1,050	-	
450	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	7,093	3,830	2,364	-	899	-	
451	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
452	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
453	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	273	148	91	-	35	-	
454	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
455	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
456	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
457	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	49	27	16	-	6	-	
458	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
459	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
460	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
461	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
462	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	646	349	215	-	82	-	
463	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
464	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
465	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
466	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	111	60	37	-	14	-	
467	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
468	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	97,156	52,460	32,375	-	12,321	-	
469	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	63,767	34,431	21,249	-	8,087	-	
470	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	9,562	5,163	3,186	-	1,213	-	
471	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
472	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
473	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	12,345	6,665	4,114	-	1,566	-	
474	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	127	69	42	-	16	-	
475	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
476	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	147,279	79,524	49,078	-	18,678	-	
477	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
478	ADJ	WTW Adjustment	6.4	P, S, T & D Plant - Demand	(2,441)	(1,318)	(813)	-	(310)	-	
479											
480		Total General Plant			347,557	187,664	115,816	-	44,077	-	
481											
482		Shared Services Customer Support:									
483											
484		General:									
485											
486	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
487	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
488	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	7,603	4,106	2,534	-	964	-	
489	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
490	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
491	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	2,183	1,179	728	-	277	-	
492	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	3,240	1,749	1,080	-	411	-	
493	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
494	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
495	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
496	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
497	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
498	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
499	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	764	412	255	-	97	-	
500	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
501	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
502	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
503	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
504	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	1,936	1,045	645	-	246	-	
505	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
506	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
507	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
508	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	606	327	202	-	77	-	
509	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	342	185	114	-	43	-	
510	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	11,120	6,004	3,705	-	1,410	-	
511	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
512	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	1,156	624	385	-	147	-	
513	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
514	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
515	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	5,385	2,907	1,794	-	683	-	
516	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	3	2	1	-	0	-	
517	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
518	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	115,996	62,632	38,653	-	14,710	-	
519	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
520											
521											
522		Total General Plant			150,334	81,173	50,095	-	19,065	-	
523											
524	NTB	To Match Schedule C-1	6.4	P, S, T & D Plant - Demand	55	30	18	-	7	-	
525											
526		TOTAL DEPRECIATION EXPENSE - DEMAND			5,028,686	2,715,256	1,675,702	0	637,729	0	

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
527		Intangible Plant:								
528										
529	30100	Organization	99.0	-	0	-	-	-	-	-
530	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
531	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
532										
533		Total Intangible Plant:			0	-	-	-	-	-
534										
535		Production Plant:								
536			99.0	-	0	-	-	-	-	-
537	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
538	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
539	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
540	33201	Field Lines	99.0	-	0	-	-	-	-	-
541	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
542	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
543	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
544										
545		Total Production Plant			0	-	-	-	-	-
546										
547		Storage Plant:								
548										
549	35010	Land	1.5	Winter Volumes	0	-	-	-	-	-
550	35020	Rights of Way	1.5	Winter Volumes	16	6	4	0	3	3
551	35100	Structures and Improvements	1.5	Winter Volumes	147	56	37	1	26	27
552	35102	Compression Station Equipment	1.5	Winter Volumes	1,531	582	384	8	273	285
553	35103	Meas. & Reg. Sta. Structues	1.5	Winter Volumes	127	48	32	1	23	24
554	35104	Other Structures	1.5	Winter Volumes	948	360	238	5	169	176
555	35200	Wells \ Rights of Way	1.5	Winter Volumes	120,988	45,964	30,335	654	21,547	22,489
556	35201	Well Construction	1.5	Winter Volumes	13,600	5,167	3,410	73	2,422	2,528
557	35202	Well Equipment	1.5	Winter Volumes	4,605	1,749	1,155	25	820	856
558	35203	Cushion Gas	1.5	Winter Volumes	11,864	4,507	2,975	64	2,113	2,205
559	35210	Leaseholds	1.5	Winter Volumes	500	190	125	3	89	93
560	35211	Storage Rights	1.5	Winter Volumes	279	106	70	2	50	52
561	35301	Field Lines	1.5	Winter Volumes	1,105	420	277	6	197	205
562	35302	Tributary Lines	1.5	Winter Volumes	1,319	501	331	7	235	245
563	35400	Compressor Station Equipment	1.5	Winter Volumes	154,463	58,681	38,728	834	27,509	28,711
564	35500	Meas & Reg. Equipment	1.5	Winter Volumes	2,553	970	640	14	455	475
565	35600	Purification Equipment	1.5	Winter Volumes	16,594	6,304	4,160	90	2,955	3,084
566										
567		Total Storage Plant			330,639	125,611	82,900	1,786	58,884	61,458
568										
569		Transmission:								
570										
571	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
572	36520	Rights of Way	99.0	-	0	-	-	-	-	-
573	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
574	36603	Other Structues	99.0	-	0	-	-	-	-	-
575	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
576	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
577	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
578	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
579	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
580										
581		Total Transmission Plant			0	-	-	-	-	-
582										
583		Distribution:								
584										
585	37400	Land & Land Rights	99.0	-	0	-	-	-	-	-
586	37401	Land	99.0	-	0	-	-	-	-	-
587	37402	Land Rights	1.0	Mcf	0	-	-	-	-	-
588	37403	Land Other	99.0	-	0	-	-	-	-	-
589	37500	Structures & Improvements	1.0	Mcf	0	-	-	-	-	-
590	37501	Structures & Improvements T.B.	1.0	Mcf	0	-	-	-	-	-
591	37502	Land Rights	1.0	Mcf	0	-	-	-	-	-
592	37503	Improvements	1.0	Mcf	0	-	-	-	-	-
593	37600	Mains Cathodic Protection	1.0	Mcf	0	-	-	-	-	-
594	37601	Mains - Steel	1.0	Mcf	0	-	-	-	-	-
595	37602	Mains - Plastic	1.0	Mcf	0	-	-	-	-	-
596	37603	Mains - Anodes	1.0	Mcf	0	-	-	-	-	-
597	37604	Mains - Leak Clamps	1.0	Mcf	0	-	-	-	-	-
598	37800	Meas & Reg. Sta. Equip - General	1.0	Mcf	0	-	-	-	-	-
599	37900	Meas & Reg. Sta. Equip - City Gate	1.0	Mcf	0	-	-	-	-	-
600	37905	Meas & Reg. Sta. Equipment T.b.	1.0	Mcf	0	-	-	-	-	-
601	38000	Services	99.0	-	0	-	-	-	-	-
602	38100	Meteres	99.0	-	0	-	-	-	-	-
603	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
604	38300	House Regulators	99.0	-	0	-	-	-	-	-
605	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
606	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
607	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
608										
609		Total Distribution Plant			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF DEPRECIATION EXPENSE										
610										
611		General:								
612										
613	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
614	39000	Structures Frame	6.6	P, S, T & D Plant - Commodity	4,690	1,782	1,176	25	835	872
615	39001	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	88	33	22	0	16	16
616	39002	Improvements	6.6	P, S, T & D Plant - Commodity	444	169	111	2	79	82
617	39003	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	12	4	3	0	2	2
618	39004	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
619	39009	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	1,892	719	474	10	337	352
620	39100	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
621	39102	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
622	39103	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	52	20	13	0	9	10
623	39200	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
624	39201	Trailers	6.6	P, S, T & D Plant - Commodity	11	4	3	0	2	2
625	39202	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
626	39300	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	3,527	1,340	884	19	628	656
627	39400	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
628	39600	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
629	39603	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
630	39604	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
631	39605	Communication Equipment	6.6	P, S, T & D Plant - Commodity	603	229	151	3	107	112
632	39700	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
633	39701	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
634	39702	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
635	39705	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	4,152	1,578	1,041	22	740	772
636	39800	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
637	39900	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
638	39901	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
639	39902	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
640	39903	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
641	39904	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
642	39905	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	230	87	58	1	41	43
643	39906	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
644	39907	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
645	39908	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
646	40600	Amortization of gas plant acquisition adjustments	6.6	P, S, T & D Plant - Commodity	1,027	390	257	6	183	191
647										
648										
649		Total General Plant			16,727	6,355	4,194	90	2,979	3,109
650										
651		TOTAL DIRECT DEPRECIATION EXPENSE			347,366	131,965	87,094	1,876	61,863	64,567
652										
653		Kentucky Mid-States General Office:								
654										
655		Intangible Plant:								
656										
657	30100	Organization	99.0	-	0	-	-	-	-	-
658	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
659	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
660										
661		Total Intangible Plant:			0	-	-	-	-	-
662										
663		General:								
664										
665	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
666	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	82	31	21	0	15	15
667	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
668	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
669	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	3	1	1	0	1	1
670	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
671	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	18	7	5	0	3	3
672	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
673	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
674	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	1	0	0	0	0	0
675	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
676	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
677	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
678	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	29	11	7	0	5	5
679	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
680	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
681	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
682	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
683	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
684	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
685	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
686	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
687	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
688	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
689	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
690	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
691	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	32	12	8	0	6	6
692	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
693	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
694	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
695	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
696	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
697	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
698	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
699										
700										
701		Total General Plant			166	63	42	1	30	31
702										
703		Shared Services General Office:								

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Customer/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF DEPRECIATION EXPENSE										
704										
705		General:								
706										
707	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
708	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	239	91	60	1	43	44
709	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
710	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
711	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
712	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	598	227	150	3	106	111
713	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	512	195	128	3	91	95
714	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
715	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
716	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	20	8	5	0	4	4
717	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
718	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
719	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
720	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	4	1	1	0	1	1
721	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
722	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
723	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
724	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
725	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	47	18	12	0	8	9
726	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
727	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
728	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
729	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	8	3	2	0	1	1
730	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
731	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	7,018	2,666	1,760	38	1,250	1,304
732	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	4,606	1,750	1,155	25	820	856
733	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	691	262	173	4	123	128
734	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
735	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
736	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	892	339	224	5	159	166
737	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	9	3	2	0	2	2
738	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
739	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	10,639	4,042	2,667	57	1,895	1,977
740	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
741	ADJ	WTW Adjustment	6.6	P, S, T & D Plant - Commodity	(176)	(67)	(44)	(1)	(31)	(33)
742										
743		Total General Plant			25,105	9,538	6,295	136	4,471	4,666
744										
745		Shared Services Customer Support:								
746										
747		General:								
748										
749	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
750	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
751	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	549	209	138	3	98	102
752	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
753	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
754	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	158	60	40	1	28	29
755	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	234	89	59	1	42	44
756	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
757	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
758	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
759	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
760	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
761	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
762	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	55	21	14	0	10	10
763	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
764	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
765	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
766	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
767	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	140	53	35	1	25	26
768	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
769	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
770	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
771	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	44	17	11	0	8	8
772	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	25	9	6	0	4	5
773	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	803	305	201	4	143	149
774	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
775	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	83	32	21	0	15	16
776	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
777	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
778	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	389	148	98	2	69	72
779	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
780	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
781	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	8,379	3,183	2,101	45	1,492	1,557
782	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
783										
784										
785		Total General Plant			10,859	4,125	2,723	59	1,934	2,018
786										
787	NTB	To Match Schedule C-1	6.6	P, S, T & D Plant - Commodity	4	2	1	0	1	1
788										
789		TOTAL DEPRECIATION EXPENSE - COMMODITY			383,501	145,693	96,154	2,072	68,299	71,284

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Total Depreciation Expense

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
790		Intangible Plant:								
791										
792	30100	Organization			0	-	-	-	-	-
793	30200	Franchises & Consents			0	-	-	-	-	-
794	30300	Misc Intangible Plant			0	-	-	-	-	-
795										
796		Total Intangible Plant:			0	-	-	-	-	-
797										
798		Production Plant:								
799					0	-	-	-	-	-
800	32520	Producing Leaseholds			0	-	-	-	-	-
801	32540	Rights of Ways			0	-	-	-	-	-
802	33100	Production Gas Wells Equipment			0	-	-	-	-	-
803	33201	Field Lines			0	-	-	-	-	-
804	33202	Tributary Lines			0	-	-	-	-	-
805	33400	Field Meas. & Reg. Sta. Equip			0	-	-	-	-	-
806	33600	Purification Equipment			0	-	-	-	-	-
807										
808		Total Production Plant			0	-	-	-	-	-
809										
810		Storage Plant:								
811										
812	35010	Land			0	-	-	-	-	-
813	35020	Rights of Way			32	15	9	0	5	3
814	35100	Structures and Improvements			294	135	86	1	45	27
815	35102	Compression Station Equipment			3,062	1,408	894	8	467	285
816	35103	Meas. & Reg. Sta. Structues			255	117	74	1	39	24
817	35104	Other Structures			1,897	872	554	5	289	176
818	35200	Wells \ Rights of Way			241,977	111,292	70,652	654	36,891	22,489
819	35201	Well Construction			27,200	12,510	7,942	73	4,147	2,528
820	35202	Well Equipment			9,210	4,236	2,689	25	1,404	856
821	35203	Cushion Gas			23,728	10,913	6,928	64	3,617	2,205
822	35210	Leaseholds			1,000	460	292	3	152	93
823	35211	Storage Rights			557	256	163	2	85	52
824	35301	Field Lines			2,209	1,016	645	6	337	205
825	35302	Tributary Lines			2,637	1,213	770	7	402	245
826	35400	Compressor Station Equipment			308,927	142,084	90,200	834	47,098	28,711
827	35500	Meas & Reg. Equipment			5,107	2,349	1,491	14	779	475
828	35600	Purification Equipment			33,187	15,264	9,690	90	5,060	3,084
829										
830		Total Storage Plant			661,278	304,140	193,078	1,786	100,815	61,458
831										
832		Transmission:								
833										
834	36510	Land & Land Rights			0	-	-	-	-	-
835	36520	Rights of Way			7,376	3,983	2,458	-	935	-
836	36602	Structures & Improvements			4,496	2,427	1,498	-	570	-
837	36603	Other Structues			0	-	-	-	-	-
838	36700	Mains Cathodic Protection			1,478	798	493	-	187	-
839	36701	Mains - Steel			384,012	207,348	127,964	-	48,700	-
840	36703	Mains - Anodes			0	-	-	-	-	-
841	36900	Meas. & Reg. Equipment			35,793	19,326	11,927	-	4,539	-
842	36901	Meas. & Reg. Equipment			40,624	21,935	13,537	-	5,152	-
843										
844		Total Transmission Plant			473,778	255,818	157,876	-	60,084	-
845										
846		Distribution:								
847										
848	37400	Land & Land Rights			0	-	-	-	-	-
849	37401	Land			0	-	-	-	-	-
850	37402	Land Rights			54,464	40,616	10,993	2	2,840	13
851	37403	Land Other			0	-	-	-	-	-
852	37500	Structures & Improvements			4,841	3,610	977	0	252	1
853	37501	Structures & Improvements T.B.			1,437	1,072	290	0	75	0
854	37502	Land Rights			666	497	134	0	35	0
855	37503	Improvements			58	43	12	0	3	0
856	37600	Mains Cathodic Protection			159,292	118,792	32,152	5	8,306	37
857	37601	Mains - Steel			3,554,207	2,650,544	717,402	102	185,333	826
858	37602	Mains - Plastic			3,416,357	2,547,743	689,577	98	178,145	794
859	37603	Mains - Anodes			200,720	149,686	40,514	6	10,466	47
860	37604	Mains - Leak Clamps			339,494	253,177	68,525	10	17,703	79
861	37800	Meas & Reg. Sta. Equip - General			573,607	427,767	115,780	16	29,911	133
862	37900	Meas & Reg. Sta. Equip - City Gate			214,735	160,138	43,343	6	11,197	50
863	37905	Meas & Reg. Sta. Equipment T.b.			37,287	27,807	7,526	1	1,944	9
864	38000	Services			4,814,131	4,273,300	535,566	233	3,141	1,891
865	38100	Meters			2,722,922	1,895,843	773,286	2,381	32,091	19,321
866	38200	Meter Installaitons			2,026,363	1,410,862	575,469	1,772	23,882	14,378
867	38300	House Regulators			124,799	86,892	35,442	109	1,471	886
868	38400	House Reg. Installations			12,401	8,635	3,522	11	146	88
869	38500	Ind. Meas. & Reg. Sta. Equipment			97,340	-	96,392	42	565	340
870	38600	Other Prop. On Cust. Prem			0	-	-	-	-	-
871										
872		Total Distribution Plant			18,355,122	14,057,024	3,746,906	4,793	507,506	38,893

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Customer/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
873											
874		General:									
875											
876	38900	Land & Land Rights			0	-	-	-	-	-	
877	39000	Structures Frame			225,186	167,827	46,641	59	9,517	1,142	
878	39001	Structures & Improvements			4,207	3,135	871	1	178	21	
879	39002	Improvements			21,302	15,876	4,412	6	900	108	
880	39003	Air Conditioning Equipment			553	412	115	0	23	3	
881	39004	Improvement to leased Premises			0	-	-	-	-	-	
882	39009	Office Furniture & Equipment			90,847	67,707	18,817	24	3,840	461	
883	39100	Remittance Processing Equip			0	-	-	-	-	-	
884	39102	Office Machines			0	-	-	-	-	-	
885	39103	Transportation Equipment			2,511	1,872	520	1	106	13	
886	39200	Trucks			0	-	-	-	-	-	
887	39201	Trailers			508	379	105	0	21	3	
888	39202	Stores Equipment			0	-	-	-	-	-	
889	39300	Tools, Shop & Garage Equipment			169,362	126,223	35,079	44	7,158	859	
890	39400	Power Operated Equipment			0	-	-	-	-	-	
891	39600	Ditchers			0	-	-	-	-	-	
892	39603	Backhoes			0	-	-	-	-	-	
893	39604	Welders			0	-	-	-	-	-	
894	39605	Communication Equipment			28,944	21,571	5,995	8	1,223	147	
895	39700	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
896	39701	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
897	39702	Communication Equip. - Telemetering			0	-	-	-	-	-	
898	39705	Miscellaneous Equipment			199,380	148,595	41,296	52	8,427	1,011	
899	39800	Other Tangible Property			0	-	-	-	-	-	
900	39900	Other Tangible Property - Servers - H/W			0	-	-	-	-	-	
901	39901	Other Tangible Property - Servers - S/W			0	-	-	-	-	-	
902	39902	Other Tangible Property - Network - H/W			0	-	-	-	-	-	
903	39903	Other Tang. Property - CPU			0	-	-	-	-	-	
904	39904	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
905	39905	Other Tang. Property - PC Hardware			11,055	8,239	2,290	3	467	56	
906	39906	Other Tang. Property - PC Software			0	-	-	-	-	-	
907	39907	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
908	39908	Other Tang. Property - Application Software			0	-	-	-	-	-	
909	40600	Amortization of gas plant acquisition adjustments			49,305	36,746	10,212	13	2,084	250	
910											
911											
912		Total General Plant			803,161	598,582	166,353	209	33,945	4,072	
913											
914		TOTAL DIRECT DEPRECIATION EXPENSE			20,293,339	15,215,565	4,264,213	6,788	702,350	104,422	
915											
916		Kentucky Mid-States General Office:									
917											
918		Intangible Plant:									
919											
920	30100	Organization			0	-	-	-	-	-	
921	30200	Franchises & Consents			0	-	-	-	-	-	
922	30300	Misc Intangible Plant			0	-	-	-	-	-	
923											
924		Total Intangible Plant:			0	-	-	-	-	-	
925											
926		General:									
927											
928	37400	Land & Land Rights			0	-	-	-	-	-	
929	39001	Structures Frame			3,943	2,939	817	1	167	20	
930	36602	Structures & Improvements			0	-	-	-	-	-	
931	38900	Land & Land Rights			0	-	-	-	-	-	
932	39004	Air Conditioning Equipment			156	116	32	0	7	1	
933	39009	Improvement to leased Premises			0	-	-	-	-	-	
934	39100	Office Furniture & Equipment			865	645	179	0	37	4	
935	39102	Remittance Processing Equip			0	-	-	-	-	-	
936	39103	Office Machines			0	-	-	-	-	-	
937	39200	Transportation Equipment			62	46	13	0	3	0	
938	39201	Trucks			0	-	-	-	-	-	
939	39202	Trailers			0	-	-	-	-	-	
940	39300	Stores Equipment			0	-	-	-	-	-	
941	39400	Tools, Shop & Garage Equipment			1,400	1,044	290	0	59	7	
942	39600	Power Operated Equipment			10	7	2	0	0	0	
943	39603	Ditchers			0	-	-	-	-	-	
944	39604	Backhoes			0	-	-	-	-	-	
945	39605	Welders			0	-	-	-	-	-	
946	39700	Communication Equipment			0	-	-	-	-	-	
947	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
948	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
949	39705	Communication Equip. - Telemetering			0	-	-	-	-	-	
950	39800	Miscellaneous Equipment			0	-	-	-	-	-	
951	39900	Other Tangible Property			0	-	-	-	-	-	
952	39901	Other Tangible Property - Servers - H/W			0	-	-	-	-	-	
953	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-	
954	39903	Other Tangible Property - Network - H/W			1,552	1,157	322	0	66	8	
955	39904	Other Tang. Property - CPU			0	-	-	-	-	-	
956	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
957	39906	Other Tang. Property - PC Hardware			0	-	-	-	-	-	
958	39907	Other Tang. Property - PC Software			0	-	-	-	-	-	
959	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
960	39909	Other Tang. Property - Application Software			0	-	-	-	-	-	
961	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-	
962											
963											
964		Total General Plant			7,989	5,954	1,655	2	338	40	
965											
966		Shared Services General Office:									

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Customer/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
967											
968		General:									
969											
970	37400	Land & Land Rights			0	-	-	-	-	-	
971	39000	Structures & Improvements			11,489	8,563	2,380	3	486	58	
972	36602	Structures & Improvements			0	-	-	-	-	-	
973	37503	Improvements			0	-	-	-	-	-	
974	39004	Air Conditioning Equipment			0	-	-	-	-	-	
975	39009	Improvement to leased Premises			28,706	21,394	5,946	7	1,213	146	
976	39100	Office Furniture & Equipment			24,600	18,334	5,095	6	1,040	125	
977	39102	Remittance Processing Equip			0	-	-	-	-	-	
978	39103	Office Machines			0	-	-	-	-	-	
979	39200	Transportation Equipment			948	707	196	0	40	5	
980	39201	Trucks			0	-	-	-	-	-	
981	39202	Trailers			0	-	-	-	-	-	
982	39300	Stores Equipment			0	-	-	-	-	-	
983	39400	Tools, Shop & Garage Equipment			171	127	35	0	7	1	
984	39600	Power Operated Equipment			0	-	-	-	-	-	
985	39603	Ditchers			0	-	-	-	-	-	
986	39604	Backhoes			0	-	-	-	-	-	
987	39605	Welders			0	-	-	-	-	-	
988	39700	Communication Equipment			2,242	1,671	464	1	95	11	
989	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
990	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
991	39705	Communication Equip. - Telemetering			0	-	-	-	-	-	
992	39800	Miscellaneous Equipment			386	288	80	0	16	2	
993	39900	Other Tangible Property			0	-	-	-	-	-	
994	39901	Other Tangible Property - Servers - H/W			336,969	251,138	69,794	88	14,242	1,708	
995	39902	Other Tangible Property - Servers - S/W			221,166	164,831	45,809	58	9,347	1,121	
996	39903	Other Tangible Property - Network - H/W			33,165	24,718	6,869	9	1,402	168	
997	39904	Other Tang. Property - CPU			0	-	-	-	-	-	
998	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
999	39906	Other Tang. Property - PC Hardware			42,815	31,909	8,868	11	1,810	217	
1000	39907	Other Tang. Property - PC Software			440	328	91	0	19	2	
1001	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
1002	39909	Other Tang. Property - Application Software			510,816	380,702	105,802	133	21,589	2,590	
1003	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-	
1004	ADJ	WTW Adjustment			(8,467)	(6,310)	(1,754)	(2)	(358)	(43)	
1005											
1006		Total General Plant			1,205,447	898,399	249,676	314	50,947	6,111	
1007											
1008		Shared Services Customer Support:									
1009											
1010		General:									
1011											
1012	37400	Land & Land Rights			0	-	-	-	-	-	
1013	39001	Structures Frame			0	-	-	-	-	-	
1014	36602	Structures & Improvements			26,371	19,654	5,462	7	1,115	134	
1015	37503	Improvements			0	-	-	-	-	-	
1016	39004	Air Conditioning Equipment			0	-	-	-	-	-	
1017	39009	Improvement to leased Premises			7,572	5,643	1,568	2	320	38	
1018	39100	Office Furniture & Equipment			11,237	8,375	2,328	3	475	57	
1019	39102	Remittance Processing Equip			0	-	-	-	-	-	
1020	39103	Office Machines			0	-	-	-	-	-	
1021	39200	Transportation Equipment			0	-	-	-	-	-	
1022	39201	Trucks			0	-	-	-	-	-	
1023	39202	Trailers			0	-	-	-	-	-	
1024	39300	Stores Equipment			0	-	-	-	-	-	
1025	39400	Tools, Shop & Garage Equipment			2,649	1,974	549	1	112	13	
1026	39600	Power Operated Equipment			0	-	-	-	-	-	
1027	39603	Ditchers			0	-	-	-	-	-	
1028	39604	Backhoes			0	-	-	-	-	-	
1029	39605	Welders			0	-	-	-	-	-	
1030	39700	Communication Equipment			6,715	5,004	1,391	2	284	34	
1031	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
1032	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
1033	39705	Communication Equip. - Telemetering			0	-	-	-	-	-	
1034	39800	Miscellaneous Equipment			2,101	1,566	435	1	89	11	
1035	39900	Other Tangible Property			1,186	884	246	0	50	6	
1036	39901	Other Tangible Property - Servers - H/W			38,567	28,743	7,988	10	1,630	196	
1037	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-	
1038	39903	Other Tangible Property - Network - H/W			4,009	2,988	830	1	169	20	
1039	39904	Other Tang. Property - CPU			0	-	-	-	-	-	
1040	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
1041	39906	Other Tang. Property - PC Hardware			18,676	13,919	3,868	5	789	95	
1042	39907	Other Tang. Property - PC Software			11	9	2	0	0	0	
1043	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
1044	39909	Other Tang. Property - Application Software			402,314	299,838	83,329	105	17,003	2,040	
1045	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-	
1046											
1047											
1048		Total General Plant			521,409	388,597	107,996	136	22,037	2,643	
1049											
1050	NTB	To Match Schedule C-1			192	143	40	0	8	1	
1051											
1052		TOTAL DEPRECIATION EXPENSE			22,028,375	16,508,658	4,623,580	7,240	775,680	113,218	

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Customer

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Taxes Other Than Income								
2									
3	Non Revenue Related:								
4	Payroll Related	7.2	Allocated O&M Expenses - Cust	67,996	58,236	9,528	10	139	83
5	Property Related	6.2	P, S, T & D Plant - Customer	8,557,007	7,204,919	1,310,759	1,829	24,656	14,844
6	DOT transmission User Tax	7.2	Allocated O&M Expenses - Cust	42,103	36,059	5,900	6	86	52
7	Other	7.2	Allocated O&M Expenses - Cust	80,382	68,843	11,264	12	164	98
8	Total Non Revenue Related:			8,747,489	7,368,057	1,337,451	1,858	25,045	15,077
9									
10	Revenue Related:								
11	State Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
12	Local Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
13	Public Service Commission Assessment	99.0	-	0	-	-	-	-	-
14	Total Revenue Related:			0	-	-	-	-	-
15									
16	Total Taxes, Other Than Income			8,747,489	7,368,057	1,337,451	1,858	25,045	15,077
17									
18									
19	Interest Expense	19.2	Rate Base - Cust	7,007,952	5,978,224	1,001,452	1,252	16,868	10,156
20									
21	Amortization of COS and Depreciation Reserves	20.2	Cost of Service - Cust	(909,307)	(771,895)	(134,348)	(165)	(2,032)	(867)
22									
23	Amortization of Excess ADIT	20.2	Cost of Service - Cust	(78,942)	(67,013)	(11,664)	(14)	(176)	(75)

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Demand

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
20	Taxes Other Than Income								
21									
22	Non Revenue Related:								
23	Payroll Related	7.4	Allocated O&M Expenses - Demand	32,309	17,445	10,766	-	4,097	-
24	Property Related	6.4	P, S, T & D Plant - Demand	3,571,206	1,928,284	1,190,028	-	452,894	-
25	DOT transmission User Tax	7.4	Allocated O&M Expenses - Demand	20,006	10,802	6,666	-	2,537	-
26	Other	7.4	Allocated O&M Expenses - Demand	38,194	20,623	12,727	-	4,844	-
27	Total Non Revenue Related:			3,661,714	1,977,154	1,220,188	0	464,372	0
28									
29	Revenue Related:								
30	State Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
31	Local Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
32	Public Service Commission Assessment	99.0	-	0	-	-	-	-	-
33	Total Revenue Related:			0	-	-	-	-	-
34									
35	Total Taxes, Other Than Income			3,661,714	1,977,154	1,220,188	-	464,372	-
36									
37									
38	Interest Expense	19.4	Rate Base - Demand	2,927,472	1,580,698	975,517	-	371,257	-
39									
40	Amortization of COS and Depreciation Reserves	20.4	Cost of Service - Demand	(373,489)	(202,319)	(124,233)	6	(47,194)	251
41									
42	Amortization of Excess ADIT	20.4	Cost of Service - Demand	(32,425)	(17,564)	(10,785)	1	(4,097)	22

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Commodity

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
39	Taxes Other Than Income								
40									
41	Non Revenue Related:								
42	Payroll Related	7.6	Allocated O&M Expenses - Comm	275,647	157,983	113,529	2,640	719	776
43	Property Related	6.6	P, S, T & D Plant - Commodity	257,961	98,000	64,677	1,393	45,941	47,949
44	DOT transmission User Tax	7.6	Allocated O&M Expenses - Comm	170,681	97,823	70,297	1,635	445	481
45	Other	7.6	Allocated O&M Expenses - Comm	325,857	186,759	134,209	3,121	849	918
46	Total Non Revenue Related:			1,030,146	540,565	382,713	8,790	47,954	50,124
47									
48	Revenue Related:								
49	State Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
50	Local Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
51	Public Service Commission Assessment	1.0	Mcf	291,875	85,778	61,643	1,836	68,270	74,350
52	Total Revenue Related:			291,875	85,778	61,643	1,836	68,270	74,350
53									
54	Total Taxes, Other Than Income			1,322,021	626,343	444,356	10,626	116,224	124,473
55									
56									
57	Interest Expense	19.6	Rate Base - Comm	304,927	90,530	60,164	1,511	73,954	78,768
58									
59	Amortization of COS and Depreciation Reserves	20.6	Cost of Service - Comm	(905,722)	(511,723)	(367,282)	(8,550)	(8,784)	(9,383)
60									
61	Amortization of Excess ADIT	20.6	Cost of Service - Comm	(78,631)	(44,426)	(31,886)	(742)	(763)	(815)

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
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ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Total Taxes Other

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
58	Taxes Other Than Income								
59									
60	Non Revenue Related:								
61	Payroll Related			375,952	233,663	133,824	2,651	4,955	860
62	Property Related			12,386,174	9,231,204	2,565,464	3,223	523,490	62,793
63	DOT transmission User Tax			232,790	144,685	82,864	1,641	3,068	532
64	Other			444,432	276,225	158,200	3,133	5,857	1,016
65	Total Non Revenue Related:			13,439,348	9,885,777	2,940,352	10,648	537,371	65,201
66									
67	Revenue Related:								
68	State Gross Receipts - Tax			0	-	-	-	-	-
69	Con Local Gross Receipts - Tax			0	-	-	-	-	-
70	Public Service Commission Assessment			291,875	85,778	61,643	1,836	68,270	74,350
71	Total Revenue Related:			291,875	85,778	61,643	1,836	68,270	74,350
72									
73	Total Taxes, Other Than Income			13,731,224	9,971,555	3,001,994	12,484	605,640	139,551
74									
75									
76	Interest Expense			10,240,350	7,649,452	2,037,133	2,763	462,079	88,923
77									
78	Amortization of COS and Depreciation Reserves			(2,188,517)	(1,485,937)	(625,863)	(8,709)	(58,010)	(9,999)
79									
80	Amortization of Excess ADIT			(189,998)	(129,003)	(54,335)	(756)	(5,036)	(868)

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF REVENUES

Total Revenues

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Rate Schedule Revenue:								
2									
3	Base Revenues	Input		96,636,506	52,550,517	26,407,052	226,254	9,273,095	8,179,588
4	Base Revenue Increase	Input		0	-	-	-	-	-
5	Gas Costs	Input		87,640,898	50,501,238	36,296,543	843,117	-	-
6	Rider FF and Rider Tax	Input		0	-	-	-	-	-
7									
8	Total Rate Schedule Revenue			184,277,404	103,051,755	62,703,595	1,069,371	9,273,095	8,179,588
9									
10	Other Revenue:								
11									
12	Forfeited Discounts	18.6	Total Rate Schedule Revenues	367,462	205,492	125,035	2,132	18,491	16,311
13	Misc. Service Revenues	18.6	Total Rate Schedule Revenues	58,912	32,945	20,046	342	2,965	2,615
14	NTB	18.2	Base Revenues	(5)	(2)	(1)	(0)	(0)	(0)
15	Other Gas Revenue	18.2	Base Revenues	3,118,240	1,695,685	852,095	7,301	299,222	263,937
16									
17	Total Non-Rate Revenue			3,544,609	1,934,120	997,175	9,775	320,677	282,862
18									
19	TOTAL REVENUE			187,822,013	104,985,875	63,700,770	1,079,146	9,593,772	8,462,450

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION FACTORS

			Total Company	Customer	Demand	Commodity
	Input	Values	1	1	0	0
1.0	Customer	%	100.0000%	100.0000%	0.0000%	0.0000%
	Input	Values	1	0	1	0
2.0	Demand	%	100.0000%	0.0000%	100.0000%	0.0000%
	Input	Values	1	0	0	1
3.0	Commodity	%	100.0000%	0.0000%	0.0000%	100.0000%
	Input	Values	100	0	50	50
3.5	Storage (50/50)	%	100.0000%	0.0000%	50.0000%	50.0000%
	Input	Values	515,352,065	305,020,486	210,331,579	0
4.0	Mains (Minimum System)	%	100.0000%	59.1868%	40.8132%	0.0000%
	Internally Generated	Values	549,923,660	388,778,539	161,145,121	0
4.1	Mains & Services	%	100.0000%	70.6968%	29.3032%	0.0000%
	Internally Generated	Values	901,469,328	622,781,459	259,913,411	18,774,458
5.4	P, S, T & D Plant	%	100.0000%	69.0852%	28.8322%	2.0827%
	Internally Generated	Values	733,894,161	506,704,961	211,373,451	15,815,749
5.7	Net Plant	%	100.0000%	69.0433%	28.8016%	2.1550%
	Internally Generated	Values	120,959,622	21,877,272	10,395,048	88,687,302
9.1	Allocated O&M Expenses	%	100.0000%	18.0864%	8.5938%	73.3198%
	Internally Generated	Values	9,527,418	5,860,571	3,393,479	273,368
10.0	Composite of Accts. 871-879 & 886-893	%	100.0000%	61.5127%	35.6180%	2.8693%
	Internally Generated	Values	431,755,369	255,542,262	176,213,107	-
12.0	Composite of Accts. 374-379	%	100.0000%	59.1868%	40.8132%	0.0000%
	Internally Generated	Values	628,233,491	429,929,614	179,596,976	18,706,901
13.0	Rate Base	%	100.0000%	68.4347%	28.5876%	2.9777%
	Internally Generated	Values	12,945,100	8,424,291	4,183,777	337,032
17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	%	100.0000%	65.0771%	32.3194%	2.6035%
	Internally Generated	Values	223,201,833	92,738,115	38,091,242	92,372,476
18.0	Total Cost of Service at Equalized ROR	%	100.0000%	41.5490%	17.0658%	41.3852%
		Values	0	0	0	0
99.0	-	%	0.0000%	0.0000%	0.0000%	0.0000%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Customer/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION FACTORS

			Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
	Input	Value	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
1.0	Mcf	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	17,293,508	9,938,593	7,142,201	212,715	-	-
1.2	Sales Mcf	%	100.0000%	57.4701%	41.2999%	1.2300%	0.0000%	0.0000%
	Input	Value	20,198,212	7,673,367	5,064,215	109,105	3,597,159	3,754,366
1.5	Winter Volumes	%	100.0000%	37.9903%	25.0726%	0.5402%	17.8093%	18.5876%
	Input	Value	2,169,218	1,925,523	241,323	105	1,415	852
2.0	Bills	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	243,695	0	241,323	105	1,415	852
2.2	Non-Residential Bills	%	100.0000%	0.0000%	99.0266%	0.0431%	0.5807%	0.3496%
	Input	Value	242,043	130,692	80,656	0	30,695	0
3.0	Peak Day	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Input	Value	85,443,836	59,490,553	24,265,293	74,716	1,007,003	606,271
4.0	Meter Investment	%	100.0000%	69.6253%	28.3991%	0.0874%	1.1786%	0.7096%
	Input	Value	1	1	-	-	-	-
4.2	Direct to Residential	%	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Input	Value	1	-	1	-	-	-
4.4	Direct to Non-Res Sales Firm	%	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
	Input	Value	1	-	-	1	-	-
4.6	Direct to Non-Res Sales Interruptible	%	100.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
	Input	Value	1	-	-	-	1	-
4.8	Direct to Transport Firm	%	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
	Input	Value	1	-	-	-	-	1
5.0	Direct to Transport Interruptible	%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Internally Generated	Value	901,469,328	671,849,702	186,715,216	234,556	38,099,781	4,570,074
6.0	P, S, T & D Plant	%	100.0000%	74.5283%	20.7123%	0.0260%	4.2264%	0.5070%
	Internally Generated	Value	622,781,459	524,376,125	95,397,405	133,142	1,794,438	1,080,350
6.2	P, S, T & D Plant - Customer	%	100.0000%	84.1991%	15.3180%	0.0214%	0.2881%	0.1735%
	Internally Generated	Value	259,913,411	140,341,099	86,610,568	0	32,961,743	0
6.4	P, S, T & D Plant - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	18,774,458	7,132,478	4,707,243	101,414	3,343,599	3,489,724
6.6	P, S, T & D Plant - Commodity	%	100.0000%	37.9903%	25.0726%	0.5402%	17.8093%	18.5876%
	Internally Generated	Value	120,959,622	75,179,326	43,056,740	852,785	1,594,170	276,602
7.0	Allocated O&M Expenses	%	100.0000%	62.1524%	35.5960%	0.7050%	1.3179%	0.2287%
	Internally Generated	Value	21,877,272	18,736,808	3,065,663	3,302	44,705	26,794
7.2	Allocated O&M Expenses - Cust	%	100.0000%	85.6451%	14.0130%	0.0151%	0.2043%	0.1225%
	Internally Generated	Value	10,395,048	5,612,840	3,463,927	0	1,318,281	0
7.4	Allocated O&M Expenses - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	88,687,302	50,829,677	36,527,151	849,483	231,184	249,808
7.6	Allocated O&M Expenses - Comm	%	100.0000%	57.3134%	41.1864%	0.9578%	0.2607%	0.2817%
	Input	Value	1,173,349	795,796	377,232	0	321	0
8.0	Customer Deposit Balances	%	100.0000%	67.8227%	32.1500%	0.0000%	0.0273%	0.0000%
	Internally Generated	Value	733,894,161	552,425,259	146,779,815	175,783	30,840,394	3,672,908
9.0	Allocated Net Plant	%	100.0000%	75.2732%	20.0001%	0.0240%	4.2023%	0.5005%
	Internally Generated	Value	506,704,961	432,285,016	72,378,730	90,351	1,217,726	733,138
9.2	Allocated Net Plant - Cust	%	100.0000%	85.3130%	14.2842%	0.0178%	0.2403%	0.1447%
	Internally Generated	Value	211,373,451	114,131,788	70,435,668	0	26,805,994	0
9.4	Allocated Net Plant - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	15,815,749	6,008,455	3,965,418	85,432	2,816,674	2,939,771
9.6	Allocated Net Plant - Comm	%	100.0000%	37.9903%	25.0726%	0.5402%	17.8093%	18.5876%
	Internally Generated	Value	9,527,418	6,934,628	2,003,211	2,779	508,571	78,229
10.0	Composite of Accts. 871-879 & 886-893	%	100.0000%	72.7860%	21.0258%	0.0292%	5.3380%	0.8211%
	Internally Generated	Value	5,860,571	5,021,969	814,673	1,059	14,275	8,594
10.2	Composite of Accts. 871-879 & 886-893 - Cust	%	100.0000%	85.6908%	13.9009%	0.0181%	0.2436%	0.1466%
	Internally Generated	Value	3,393,479	1,832,320	1,130,804	0	430,355	0
10.4	Composite of Accts. 871-879 & 886-893 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	273,368	80,338	57,734	1,719	63,941	69,635
10.6	Composite of Accts. 871-879 & 886-893 - Comm	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	549,923,660	432,113,065	96,949,315	18,819	20,689,761	152,700
11.0	Composite of Accts. 376 & 380	%	100.0000%	78.5769%	17.6296%	0.0034%	3.7623%	0.0278%
	Internally Generated	Value	388,778,539	345,102,228	43,251,161	18,819	253,631	152,700
11.2	Composite of Accts. 376 & 380 - Cust	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	161,145,121	87,010,837	53,698,154	0	20,436,130	0
11.4	Composite of Accts. 376 & 380 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
11.6	Composite of Accts. 376 & 380 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION FACTORS

			Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
	Internally Generated	Value	431,755,369	321,980,879	87,148,017	12,369	22,513,735	100,369
12.0	Composite of Accts. 374-379	%	100.0000%	74.5748%	20.1846%	0.0029%	5.2145%	0.0232%
	Internally Generated	Value	255,542,262	226,834,033	28,428,780	12,369	166,711	100,369
12.2	Composite of Accts. 374-379 - Cust	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	176,213,107	95,146,846	58,719,238	0	22,347,024	0
12.4	Composite of Accts. 374-379 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
12.6	Composite of Accts. 374-379 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	74,469,926	51,849,932	21,148,799	65,120	877,669	528,405
13.0	Composite of Accts. 381-383	%	100.0000%	69.6253%	28.3991%	0.0874%	1.1786%	0.7096%
	Internally Generated	Value	74,469,926	51,849,932	21,148,799	65,120	877,669	528,405
13.2	Composite of Accts. 381-383 - Cust	%	100.0000%	69.6253%	28.3991%	0.0874%	1.1786%	0.7096%
	Internally Generated	Value	0	0	0	0	0	0
13.4	Composite of Accts. 381-383 - Demand	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
13.6	Composite of Accts. 381-383 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	155,087,701	137,664,778	17,253,327	7,507	101,176	60,914
14.0	Account 380	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	155,087,701	137,664,778	17,253,327	7,507	101,176	60,914
14.2	Account 380 - Cust	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	0	0	0	0	0	0
14.4	Account 380 - Demand	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
14.6	Account 380 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	12,945,100	9,613,798	2,603,106	3,484	627,792	96,919
17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	%	100.0000%	74.2659%	20.1088%	0.0269%	4.8497%	0.7487%
	Internally Generated	Value	8,424,291	7,255,706	1,137,773	1,364	18,381	11,067
17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	%	100.0000%	86.1284%	13.5059%	0.0162%	0.2182%	0.1314%
	Internally Generated	Value	4,183,777	2,259,044	1,394,154	0	530,579	0
17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	337,032	99,048	71,179	2,120	78,832	85,852
17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	187,822,013	104,985,875	63,700,770	1,079,146	9,593,772	8,462,450
18.0	Revenues	%	100.0000%	55.8965%	33.9155%	0.5746%	5.1079%	4.5056%
	Internally Generated	Value	96,636,506	52,550,517	26,407,052	226,254	9,273,095	8,179,588
18.2	Base Revenues	%	100.0000%	54.3796%	27.3262%	0.2341%	9.5959%	8.4643%
	Internally Generated	Value	87,640,898	50,501,238	36,296,543	843,117	-	-
18.4	Gas Costs	%	100.0000%	57.6229%	41.4151%	0.9620%	0.0000%	0.0000%
	Internally Generated	Value	184,277,404	103,051,755	62,703,595	1,069,371	9,273,095	8,179,588
18.6	Total Rate Schedule Revenues	%	100.0000%	55.9221%	34.0267%	0.5803%	5.0321%	4.4387%
	Internally Generated	Value	628,233,491	469,284,905	124,975,725	169,497	28,348,014	5,455,350
19.0	Rate Base	%	100.0000%	74.6991%	19.8932%	0.0270%	4.5123%	0.8684%
	Internally Generated	Value	429,929,614	366,757,040	61,437,887	76,784	1,034,857	623,046
19.2	Rate Base - Cust	%	100.0000%	85.3063%	14.2902%	0.0179%	0.2407%	0.1449%
	Internally Generated	Value	179,596,976	96,973,977	59,846,839	0	22,776,160	0
19.4	Rate Base - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	18,706,901	5,553,889	3,690,998	92,713	4,536,997	4,832,304
19.6	Rate Base - Comm	%	100.0000%	29.6890%	19.7307%	0.4956%	24.2531%	25.8317%
	Internally Generated	Value	223,201,833	151,547,233	63,830,359	888,197	5,916,269	1,019,775
20.0	Cost of Service	%	100.0000%	67.8969%	28.5976%	0.3979%	2.6506%	0.4569%
	Internally Generated	Value	92,738,115	78,723,768	13,701,838	16,868	207,200	88,441
20.2	Cost of Service - Cust	%	100.0000%	84.8883%	14.7748%	0.0182%	0.2234%	0.0954%
	Internally Generated	Value	38,091,242	20,634,013	12,670,262	(662)	4,813,236	(25,607)
20.4	Cost of Service - Demand	%	100.0000%	54.1700%	33.2629%	-0.0017%	12.6361%	-0.0672%
	Internally Generated	Value	92,372,476	52,189,452	37,458,259	871,991	895,833	956,942
20.6	Cost of Service - Comm	%	100.0000%	56.4989%	40.5513%	0.9440%	0.9698%	1.0360%
	Internally Generated	Value	216,905,276	156,189,331	50,152,810	71,608	9,344,278	1,147,249
21.0	Depreciation Reserve	%	100.0000%	72.0081%	23.1220%	0.0330%	4.3080%	0.5289%
	Internally Generated	Value	150,156,279	120,785,963	28,239,002	50,076	674,907	406,331
21.2	Depreciation Reserve - Cust	%	100.0000%	80.4402%	18.8064%	0.0333%	0.4495%	0.2706%
	Internally Generated	Value	62,762,914	33,889,041	20,914,395	0	7,959,478	0
21.4	Depreciation Reserve - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	3,986,083	1,514,326	999,414	21,532	709,893	740,918
21.6	Depreciation Reserve - Comm	%	100.0000%	37.9903%	25.0726%	0.5402%	17.8093%	18.5876%
		Value	0	0	0	0	0	0
99.0	-	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF RESULTS

			Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
			$					
Operating Revenues			187,822,013	104,985,875	63,700,770	1,079,146	9,593,772	8,462,450
Operating Expenses:								
Operating & Maintenance			120,959,622	70,151,559	46,266,542	852,085	3,418,513	270,923
Depreciation & Amortization			22,028,375	14,452,852	5,936,037	6,953	1,521,636	110,896
Taxes Other Than Income			13,731,224	8,489,267	3,948,309	12,277	1,143,494	137,876
Total Operating Expenses			156,719,221	93,093,679	56,150,888	871,316	6,083,644	519,695
Income Before Taxes			31,102,792	11,892,197	7,549,882	207,831	3,510,128	7,942,755
Interest Expense			10,240,350	6,375,633	2,850,358	2,586	924,289	87,485
Income Taxes:								
State Income Taxes		5.00%	1,043,122	275,828	234,976	10,262	129,292	392,764
Federal Income Taxes		21.00%	4,162,057	1,100,554	937,555	40,946	515,875	1,567,126
Total Deferred Income Taxes			0	0	0	0	0	0
Amortization of ITC			0	0	0	0	0	0
Total Income Taxes			5,205,179	1,376,383	1,172,531	51,209	645,167	1,959,890
Net Income			25,897,613	10,515,814	6,377,351	156,622	2,864,961	5,982,865
Total Rate Base			628,233,491	391,137,597	174,866,150	158,618	56,704,051	5,367,075
Rate of Return			4.1223%	2.6885%	3.6470%	98.7416%	5.0525%	111.4735%
Relative Rate of Return			1.00	0.65	0.88	23.95	1.23	27.04
Equalized ROR:			52,143,380	32,464,421	14,513,890	13,165	4,706,436	445,467
Net Income Increase			26,245,767	21,948,607	8,136,540	(143,457)	1,841,475	(5,537,398)
Uncollectibles/PSC Fees Increase		1.1554%	408,778	341,850	126,727	(2,234)	28,681	(86,245)
Income Taxes			8,725,275	7,296,705	2,704,952	(47,691)	612,189	(1,840,880)
Gross Revenue After Increase			223,201,833	134,573,037	74,668,989	885,764	12,076,117	997,926
Revenue Deficiency			35,379,820	29,587,162	10,968,218	(193,383)	2,482,345	(7,464,523)
Rate of Return			8.3000%	8.3000%	8.3000%	8.3000%	8.3000%	8.3000%
Relative Rate of Return			1.00	1.00	1.00	1.00	1.00	1.00
Percent Increase			18.8369%	28.1820%	17.2183%	-17.9200%	25.8745%	-88.2076%
Proposed Rate Levels:								
Net Income Increase			26,245,662	14,909,209	5,905,961	65,857	3,229,532	2,135,103
Uncollectibles/PSC Fees Increase			408,777	232,211	91,985	1,026	50,300	33,254
Income Taxes			8,725,240	4,956,492	1,963,408	21,894	1,073,642	709,804
Gross Revenue After Increase			223,201,693	125,083,788	71,662,124	1,167,924	13,947,246	11,340,611
Revenue Deficiency			35,379,679	20,097,912	7,961,354	88,777	4,353,474	2,878,162
Rate of Return			8.3000%	6.5003%	7.0244%	140.2611%	10.7479%	151.2550%
Relative Rate of Return			1.00	0.78	0.85	16.90	1.29	18.22
Percent Increase			18.8368%	19.1434%	12.4981%	8.2266%	45.3781%	34.0110%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF CUSTOMER COSTS

		Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
		$					
1	Rate Base	205,177,426	167,254,050	36,434,468	65,905	888,233	534,770
2							
3	Return @ Realized ROR	8,458,011	5,063,153	1,230,489	51,733	208,879	1,903,756
4	O&M Expenses	7,417,382	5,901,377	1,457,017	2,602	35,271	21,115
5	Depreciation Expense	10,703,678	8,399,424	2,193,964	4,882	65,795	39,612
6	Taxes, Other	4,484,419	3,583,912	863,189	1,652	22,264	13,403
7							
8	Interest Expense	3,344,439	2,726,279	593,890	1,074	14,478	8,717
9							
10	Income Taxes:						
11							
12	State Income Taxes	340,678	155,688	42,412	3,375	12,951	126,252
13	Federal Income Taxes	1,359,304	621,194	169,222	13,466	51,676	503,745
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	1,699,981	776,882	211,634	16,841	64,628	629,996
18							
19	Total Customer-Related Costs @ Realized ROR	32,763,472	23,724,748	5,956,293	77,710	396,837	2,607,883
20	Total Customers	180,768	160,460	20,110	9	118	71
21	Customer Costs ($/customer/month)	$ 15.10	$ 12.32	$ 24.68	$ 740.10	$ 280.42	$ 3,060.90
22							
23							
24	Incremental Return @ Equalized ROR	8,571,716	8,818,933	1,793,572	(46,263)	(135,156)	(1,859,370)
25	Incremental Income Taxes	2,849,624	2,931,811	596,264	(15,380)	(44,932)	(618,138)
26	Incremental Uncollectibles/PSC Fees Increase	133,505	137,355	27,935	(721)	(2,105)	(28,960)
27							
28	Total Customer-Related Costs @ Equalized ROR	44,318,316	35,612,847	8,374,064	15,347	214,644	101,414
29	Customers	180,768	160,460	20,110	9	118	71
30	Dollars/Customer/Month	$ 20.43	$ 18.50	$ 34.70	$ 146.16	$ 151.68	$ 119.03
31							
32							
33	Incremental Return @ Proposed Rates	8,571,682	6,519,900	1,065,081	22,098	318,178	646,424
34	Incremental Income Taxes	2,849,613	2,167,508	354,081	7,346	105,777	214,901
35	Incremental Uncollectibles/PSC Fees Increase	133,504	101,548	16,589	344	4,956	10,068
36							
37	Total Customer-Related Costs @ Proposed Rates	44,318,270	32,513,704	7,392,044	107,498	825,748	3,479,276
38	Customers	180,768	160,460	20,110	9	118	71
39	Dollars/Customer/Month	$ 20.43	$ 16.89	$ 30.63	$ 1,023.79	$ 583.50	$ 4,083.66

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF DEMAND COSTS

		Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
		$					
1	Rate Base	404,349,163	218,329,658	134,740,684	0	51,278,821	0
2							
3	Return @ Realized ROR	16,668,450	5,390,703	5,019,457	96,598	2,453,348	3,708,344
4	O&M Expenses	24,854,938	13,420,505	8,282,375	0	3,152,058	0
5	Depreciation Expense	10,941,196	5,907,735	3,645,919	0	1,387,542	0
6	Taxes, Other	7,924,783	4,279,013	2,640,764	0	1,005,006	0
7							
8	Interest Expense	6,590,984	3,558,824	2,196,304	0	835,857	0
9							
10	Income Taxes:						
11							
12	State Income Taxes	671,383	122,044	188,085	6,436	107,761	247,058
13	Federal Income Taxes	2,678,820	486,955	750,458	25,678	429,966	985,762
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	3,350,203	608,999	938,543	32,114	537,727	1,232,820
18							
19	Total Demand-Related Costs @ Realized ROR	63,739,570	29,606,955	20,527,058	128,711	8,535,681	4,941,164
20							
21							
22	Incremental Return @ Equalized ROR	16,892,531	12,730,658	6,164,020	(96,598)	1,802,794	(3,708,344)
23	Incremental Income Taxes	5,615,838	4,232,244	2,049,198	(32,114)	599,330	(1,232,820)
24	Incremental Uncollectibles/PSC Fees Increase	263,102	198,280	96,005	(1,505)	28,079	(57,758)
25							
26	Total Demand-Related Costs @ Equalized ROR	86,511,041	46,768,138	28,836,280	(1,505)	10,965,885	(57,758)
27							
28							
29	Incremental Return @ Proposed Rates	16,892,464	8,199,905	4,728,352	38,123	2,696,186	1,229,899
30	Incremental Income Taxes	5,615,816	2,726,018	1,571,917	12,674	896,334	408,874
31	Incremental Uncollectibles/PSC Fees Increase	263,101	127,714	73,644	594	41,993	19,156
32							
33	Total Demand-Related Costs @ Proposed Rates	86,510,951	40,660,591	26,900,971	180,102	12,170,194	6,599,093

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF COMMODITY COSTS

		Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
		$					
1	Rate Base	18,706,901	5,553,889	3,690,998	92,713	4,536,997	4,832,304
2							
3	Return @ Realized ROR	771,153	228,947	152,154	3,822	187,028	199,202
4	O&M Expenses	88,687,302	50,829,677	36,527,151	849,483	231,184	249,808
5	Depreciation Expense	383,501	145,693	96,154	2,072	68,299	71,284
6	Taxes, Other	1,322,021	626,343	444,356	10,626	116,224	124,473
7							
8	Interest Expense	304,927	90,530	60,164	1,511	73,954	78,768
9							
10	Income Taxes:						
11							
12	State Income Taxes	31,061	9,222	6,129	154	7,533	8,024
13	Federal Income Taxes	123,934	36,795	24,453	614	30,058	32,014
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	154,995	46,016	30,581	768	37,591	40,038
18							
19	Total Commodity-Related Costs	91,318,971	51,876,677	37,250,395	866,770	640,326	684,804
20	Total Throughput	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
21	Commodity Costs ($/Mcf)		$ 5.21972	$ 5.21553	$ 4.07480	$ 0.08095	$ 0.08
22							
23							
24	Incremental Return @ Equalized ROR	781,520	232,025	154,199	3,873	189,543	201,880
25	Incremental Income Taxes	259,812	77,136	51,263	1,288	63,012	67,114
26	Incremental Uncollectibles/PSC Fees Increase	12,172	3,614	2,402	60	2,952	3,144
27							
28	Total Commodity-Related Costs @ Equalized ROR	92,372,476	52,189,452	37,458,259	871,991	895,833	956,942
29	Total Throughput	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
30	Commodity Costs ($/Mcf)	$ 2.73	$ 5.25	$ 5.24	$ 4.10	$ 0.11	$ 0.11
31							
32							
33	Incremental Return @ Proposed Rates	781,517	22,414	87,780	10,106	230,874	430,343
34	Incremental Income Taxes	259,811	7,452	29,182	3,360	76,753	143,065
35	Incremental Uncollectibles/PSC Fees Increase	12,172	349	1,367	157	3,596	6,703
36							
37	Total Commodity-Related Costs @ Proposed Rates	92,372,472	51,906,892	37,368,724	880,393	951,549	1,264,915
38	Total Throughput	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
39	Commodity Costs ($/Mcf)	$ 2.73	$ 5.22	$ 5.23	$ 4.14	$ 0.12	$ 0.15

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

TOTAL COST OF SERVICE

		Total Company $	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Rate Base	628,233,491	391,137,597	174,866,150	158,618	56,704,051	5,367,075
2							
3	Return @ Realized ROR	25,897,613	10,682,804	6,402,100	152,153	2,849,255	5,811,301
4	O&M Expenses	120,959,622	70,151,559	46,266,542	852,085	3,418,513	270,923
5	Depreciation Expense	22,028,375	14,452,852	5,936,037	6,953	1,521,636	110,896
6	Taxes, Other	13,731,224	8,489,267	3,948,309	12,277	1,143,494	137,876
7							
8	Interest Expense	10,240,350	6,375,633	2,850,358	2,586	924,289	87,485
9							
10	Income Taxes:						
11							
12	State Income Taxes	1,043,122	286,953	236,625	9,965	128,246	381,334
13	Federal Income Taxes	4,162,057	1,144,944	944,134	39,758	511,700	1,521,521
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	5,205,179	1,431,898	1,180,759	49,723	639,945	1,902,854
18							
19	Total Cost of Service @ Realized ROR	187,822,013	105,208,380	63,733,747	1,073,192	9,572,844	8,233,850
20							
21							
22	Incremental Return @ Equalized ROR	26,245,767	21,781,617	8,111,791	(138,988)	1,857,181	(5,365,834)
23	Incremental Income Taxes	8,725,275	7,241,190	2,696,725	(46,206)	617,411	(1,783,845)
24	Incremental Uncollectibles/PSC Fees Increase	408,778	339,249	126,341	(2,165)	28,926	(83,573)
25							
26	Total Cost of Service @ Equalized ROR	223,201,833	134,570,436	74,668,603	885,833	12,076,362	1,000,598
27							
28							
29	Incremental Return @ Proposed Rates	26,245,662	14,742,219	5,881,212	70,326	3,245,238	2,306,667
30	Incremental Income Taxes	8,725,240	4,900,977	1,955,180	23,380	1,078,863	766,840
31	Incremental Uncollectibles/PSC Fees Increase	408,777	229,610	91,600	1,095	50,545	35,926
32							
33	Total Cost of Service @ Proposed Rates	223,201,693	125,081,187	71,661,739	1,167,993	13,947,491	11,343,283

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF GROSS PLANT IN SERVICE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Intangible Plant:						
2								
3	30100	Organization	8,330	5.4	P, S, T & D Plant	2,972	5,184	173
4	30200	Franchises & Consents	119,853	5.4	P, S, T & D Plant	42,768	74,589	2,496
5	30300	Misc Intangible Plant	-	99.0	-	-	-	-
6								
7		Total Intangible Plant:	128,182			45,740	79,773	2,670
8								
9		Production Plant:						
10								
11	32520	Producing Leaseholds	-	99.0	-	-	-	-
12	32540	Rights of Ways	-	99.0	-	-	-	-
13	33100	Production Gas Wells Equipment	-	99.0	-	-	-	-
14	33201	Field Lines	-	99.0	-	-	-	-
15	33202	Tributary Lines	-	99.0	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	-	99.0	-	-	-	-
17	33600	Purification Equipment	-	99.0	-	-	-	-
18								
19		Total Production Plant	-			0	0	0
20								
21		Storage Plant:						
22								
23	35010	Land	261,127	3.5	Storage (50/50)	-	130,563	130,563
24	35020	Rights of Way	4,682	3.5	Storage (50/50)	-	2,341	2,341
25	35100	Structures and Improvements	17,916	3.5	Storage (50/50)	-	8,958	8,958
26	35102	Compression Station Equipment	223,508	3.5	Storage (50/50)	-	111,754	111,754
27	35103	Meas. & Reg. Sta. Structues	23,138	3.5	Storage (50/50)	-	11,569	11,569
28	35104	Other Structures	137,443	3.5	Storage (50/50)	-	68,721	68,721
29	35200	Wells \ Rights of Way	12,534,611	3.5	Storage (50/50)	-	6,267,306	6,267,306
30	35201	Well Construction	1,699,999	3.5	Storage (50/50)	-	849,999	849,999
31	35202	Well Equipment	667,359	3.5	Storage (50/50)	-	333,680	333,680
32	35203	Cushion Gas	1,694,833	3.5	Storage (50/50)	-	847,416	847,416
33	35210	Leaseholds	178,530	3.5	Storage (50/50)	-	89,265	89,265
34	35211	Storage Rights	54,614	3.5	Storage (50/50)	-	27,307	27,307
35	35301	Field Lines	175,350	3.5	Storage (50/50)	-	87,675	87,675
36	35302	Tributary Lines	209,319	3.5	Storage (50/50)	-	104,659	104,659
37	35400	Compressor Station Equipment	18,065,905	3.5	Storage (50/50)	-	9,032,953	9,032,953
38	35500	Meas & Reg. Equipment	273,084	3.5	Storage (50/50)	-	136,542	136,542
39	35600	Purification Equipment	1,327,498	3.5	Storage (50/50)	-	663,749	663,749
40								
41		Total Storage Plant	37,548,916			0	18,774,458	18,774,458
42								
43		Transmission:						
44								
45	36510	Land & Land Rights	26,970	2.0	Demand	-	26,970	-
46	36520	Rights of Way	867,772	2.0	Demand	-	867,772	-
47	36602	Structures & Improvements	397,833	2.0	Demand	-	397,833	-
48	36603	Other Structues	60,826	2.0	Demand	-	60,826	-
49	36700	Mains Cathodic Protection	47,233	2.0	Demand	-	47,233	-
50	36701	Mains - Steel	27,826,921	2.0	Demand	-	27,826,921	-
51	36703	Mains - Anodes	11,134	2.0	Demand	-	11,134	-
52	36900	Meas. & Reg. Equipment	1,999,587	2.0	Demand	-	1,999,587	-
53	36901	Meas. & Reg. Equipment	2,269,499	2.0	Demand	-	2,269,499	-
54								
55		Total Transmission Plant	33,507,777			0	33,507,777	0
56								
57		Distribution:						
58								
59	37400	Land & Land Rights	613,356	4.0	Mains (All Demand)	-	613,356	-
60	37401	Land	428,640	4.0	Mains (All Demand)	-	428,640	-
61	37402	Land Rights	4,157,536	4.0	Mains (All Demand)	-	4,157,536	-
62	37403	Land Other	2,784	4.0	Mains (All Demand)	-	2,784	-
63	37500	Structures & Improvements	336,168	4.0	Mains (All Demand)	-	336,168	-
64	37501	Structures & Improvements T.B.	99,818	4.0	Mains (All Demand)	-	99,818	-
65	37502	Land Rights	46,264	4.0	Mains (All Demand)	-	46,264	-
66	37503	Improvements	4,005	4.0	Mains (All Demand)	-	4,005	-
67	37600	Mains Cathodic Protection	3,418,283	4.0	Mains (All Demand)	-	3,418,283	-
68	37601	Mains - Steel	230,553,919	4.0	Mains (All Demand)	-	230,553,919	-
69	37602	Mains - Plastic	221,659,304	4.0	Mains (All Demand)	-	221,659,304	-
70	37603	Mains - Anodes	3,599,610	4.0	Mains (All Demand)	-	3,599,610	-
71	37604	Mains - Leak Clamps	6,789,879	4.0	Mains (All Demand)	-	6,789,879	-
72	37800	Meas & Reg. Sta. Equip - General	25,594,946	4.0	Mains (All Demand)	-	25,594,946	-
73	37900	Meas & Reg. Sta. Equip - City Gate	9,712,761	4.0	Mains (All Demand)	-	9,712,761	-
74	37905	Meas & Reg. Sta. Equipment T.b.	1,718,293	4.0	Mains (All Demand)	-	1,718,293	-
75	38000	Services	193,916,542	1.0	Customer	193,916,542	-	-
76	38100	Meters	55,920,540	1.0	Customer	55,920,540	-	-
77	38200	Meter Installations	61,761,518	1.0	Customer	61,761,518	-	-
78	38300	House Regulators	3,974,497	1.0	Customer	3,974,497	-	-
79	38400	House Reg. Installations	378,094	1.0	Customer	378,094	-	-
80	38500	Ind. Meas. & Reg. Sta. Equipment	5,725,878	1.0	Customer	5,725,878	-	-
81	38600	Other Prop. On Cust. Prem	-	99.0	-	-	-	-
82								
83		Total Distribution Plant	830,412,635			321,677,069	508,735,567	0
84								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF GROSS PLANT IN SERVICE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
85		General:						
86								
87	38900	Land & Land Rights	1,211,697	5.4	P, S, T & D Plant	432,378	754,084	25,235
88	39000	Structures & Improvements	9,256,964	5.4	P, S, T & D Plant	3,303,222	5,760,952	192,790
89	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
90	39002	Structures-Brick	173,115	5.4	P, S, T & D Plant	61,774	107,736	3,605
91	39003	Improvements	876,634	5.4	P, S, T & D Plant	312,815	545,562	18,257
92	39004	Air Conditioning Equipment	12,955	5.4	P, S, T & D Plant	4,623	8,062	270
93	39009	Improvement to leased Premises	1,267,195	5.4	P, S, T & D Plant	452,181	788,623	26,391
94	39100	Office Furniture & Equipment	1,816,939	5.4	P, S, T & D Plant	648,350	1,130,748	37,840
95	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
96	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
97	39200	Transportation Equipment	180,749	5.4	P, S, T & D Plant	64,498	112,487	3,764
98	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
99	39202	Trailers	36,588	5.4	P, S, T & D Plant	13,056	22,770	762
100	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
101	39400	Tools, Shop & Garage Equipment	7,143,379	5.4	P, S, T & D Plant	2,549,018	4,445,590	148,772
102	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
103	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
104	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
105	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
106	39700	Communication Equipment	433,938	5.4	P, S, T & D Plant	154,845	270,056	9,037
107	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
108	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
109	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
110	39800	Miscellaneous Equipment	2,982,913	5.4	P, S, T & D Plant	1,064,412	1,856,377	62,124
111	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
112	39901	Other Tangible Property - Servers - H/W	21,425	5.4	P, S, T & D Plant	7,645	13,334	446
113	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
114	39903	Other Tangible Property - Network - H/W	-	5.4	P, S, T & D Plant	-	-	-
115	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
116	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
117	39906	Other Tang. Property - PC Hardware	530,662	5.4	P, S, T & D Plant	189,359	330,250	11,052
118	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
119	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
120	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
121	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
122								
123		Total General Plant	25,945,153			9,258,175	16,146,631	540,347
124								
125		TOTAL DIRECT PLANT	927,542,664			330,980,984	577,244,205	19,317,475
126								
127		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
128								
129		Kentucky Mid-States General Office:						
130								
131		Intangible Plant:						
132								
133	30100	Organization	92,599	5.4	P, S, T & D Plant	33,043	57,628	1,929
134	30200	Franchises & Consents	-	5.4	P, S, T & D Plant	-	-	-
135	30300	Misc Intangible Plant	554,443	5.4	P, S, T & D Plant	197,845	345,050	11,547
136								
137		Total Intangible Plant:	647,042			230,888	402,678	13,476
138								
139		General:						
140								
141	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
142	39001	Structures Frame	89,615	5.4	P, S, T & D Plant	31,978	55,771	1,866
143	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
144	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
145	39004	Air Conditioning Equipment	7,687	5.4	P, S, T & D Plant	2,743	4,784	160
146	39009	Improvement to leased Premises	19,405	5.4	P, S, T & D Plant	6,925	12,077	404
147	39100	Office Furniture & Equipment	13,456	5.4	P, S, T & D Plant	4,802	8,374	280
148	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
149	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
150	39200	Transportation Equipment	2,054	5.4	P, S, T & D Plant	733	1,278	43
151	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
152	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
153	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
154	39400	Tools, Shop & Garage Equipment	55,081	5.4	P, S, T & D Plant	19,655	34,279	1,147
155	39600	Power Operated Equipment	4,736	5.4	P, S, T & D Plant	1,690	2,948	99
156	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
157	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
158	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
159	39700	Communication Equipment	-	5.4	P, S, T & D Plant	-	-	-
160	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
161	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
162	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
163	39800	Miscellaneous Equipment	-	5.4	P, S, T & D Plant	-	-	-
164	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
165	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
166	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
167	39903	Other Tangible Property - Network - H/W	14,125	5.4	P, S, T & D Plant	5,040	8,790	294
168	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
169	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
170	39906	Other Tang. Property - PC Hardware	-	5.4	P, S, T & D Plant	-	-	-
171	39907	Other Tang. Property - PC Software	21,748	5.4	P, S, T & D Plant	7,760	13,535	453
172	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
173	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
174	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
175								
176		Total General Plant	227,907			81,326	141,835	4,747
177								
178		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
179								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF GROSS PLANT IN SERVICE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
180		Shared Services General Office:						
181								
182		General:						
183								
184	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
185	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
186	36602	Structures & Improvements	483,221	5.4	P, S, T & D Plant	172,431	300,727	10,064
187	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
188	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
189	39009	Improvement to leased Premises	642,376	5.4	P, S, T & D Plant	229,223	399,775	13,378
190	39100	Office Furniture & Equipment	384,176	5.4	P, S, T & D Plant	137,088	239,087	8,001
191	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
192	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
193	39200	Transportation Equipment	14,389	5.4	P, S, T & D Plant	5,135	8,955	300
194	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
195	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
196	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
197	39400	Tools, Shop & Garage Equipment	1,375	5.4	P, S, T & D Plant	491	856	29
198	39500	Tools, Shop & Garage Equipment	-	5.4	P, S, T & D Plant	-	-	-
199	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
200	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
201	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
202	39700	Communication Equipment	35,202	5.4	P, S, T & D Plant	12,561	21,907	733
203	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
204	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
205	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
206	39800	Miscellaneous Equipment	5,516	5.4	P, S, T & D Plant	1,968	3,433	115
207	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
208	39901	Other Tangible Property - Servers - H/W	2,628,270	5.4	P, S, T & D Plant	937,862	1,635,670	54,738
209	39902	Other Tangible Property - Servers - S/W	2,115,244	5.4	P, S, T & D Plant	754,796	1,316,395	44,053
210	39903	Other Tangible Property - Network - H/W	292,050	5.4	P, S, T & D Plant	104,214	181,754	6,082
211	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
212	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
213	39906	Other Tang. Property - PC Hardware	214,855	5.4	P, S, T & D Plant	76,668	133,712	4,475
214	39907	Other Tang. Property - PC Software	3,774	5.4	P, S, T & D Plant	1,347	2,349	79
215	39908	Other Tang. Property - Mainframe S/W	4,940,307	5.4	P, S, T & D Plant	1,762,881	3,074,536	102,889
216	39909	Other Tang. Property - Application Software	1,654,844	5.4	P, S, T & D Plant	590,509	1,029,871	34,465
217	39931	Other Tang. Property - ALGN	799,338	5.4	P, S, T & D Plant	285,233	497,458	16,647
218								
219		Total General Plant	14,214,939			5,072,408	8,846,484	296,048
220								
221		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
222								
223		Shared Services Customer Support:						
224								
225		General:						
226								
227	37400	Land & Land Rights	211,229	5.4	P, S, T & D Plant	75,374	131,455	4,399
228	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
229	36602	Structures & Improvements	1,107,950	5.4	P, S, T & D Plant	395,357	689,519	23,075
230	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
231	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
232	39009	Improvement to leased Premises	170,931	5.4	P, S, T & D Plant	60,995	106,377	3,560
233	39100	Office Furniture & Equipment	176,418	5.4	P, S, T & D Plant	62,952	109,791	3,674
234	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
235	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
236	39200	Transportation Equipment	2,237	5.4	P, S, T & D Plant	798	1,392	47
237	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
238	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
239	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
240	39400	Tools, Shop & Garage Equipment	21,259	5.4	P, S, T & D Plant	7,586	13,230	443
241	39510	Laboratory Equip	-	5.4	P, S, T & D Plant	-	-	-
242	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
243	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
244	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
245	39700	Communication Equipment	105,908	5.4	P, S, T & D Plant	37,792	65,911	2,206
246	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
247	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
248	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
249	39800	Miscellaneous Equipment	29,842	5.4	P, S, T & D Plant	10,649	18,572	621
250	39900	Other Tangible Property	8,234	5.4	P, S, T & D Plant	2,938	5,124	171
251	39901	Other Tangible Property - Servers - H/W	304,635	5.4	P, S, T & D Plant	108,705	189,586	6,344
252	39902	Other Tangible Property - Servers - S/W	98,374	5.4	P, S, T & D Plant	35,104	61,222	2,049
253	39903	Other Tangible Property - Network - H/W	35,543	5.4	P, S, T & D Plant	12,683	22,119	740
254	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
255	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
256	39906	Other Tang. Property - PC Hardware	93,706	5.4	P, S, T & D Plant	33,438	58,317	1,952
257	39907	Other Tang. Property - PC Software	98	5.4	P, S, T & D Plant	35	61	2
258	39908	Other Tang. Property - Mainframe S/W	5,800,519	5.4	P, S, T & D Plant	2,069,836	3,609,878	120,805
259	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
260	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
261								
262		Total General Plant	8,166,885			2,914,242	5,082,555	170,088
263								
264		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
265								
266		TOTAL PLANT IN SERVICE	950,799,437			339,279,847	591,717,758	19,801,832
267								
268		TOTAL CWIP W/O AFUDC	-			0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Intangible Plant:						
2								
3	30100	Organization	8,330	5.4	P, S, T & D Plant	2,972	5,184	173
4	30200	Franchises & Consents	119,853	5.4	P, S, T & D Plant	42,768	74,589	2,496
5	30300	Misc Intangible Plant	-	99.0	-	-	-	-
6								
7		Total Intangible Plant:	128,182			45,740	79,773	2,670
8								
9		Production Plant:						
10								
11	32520	Producing Leaseholds	-	99.0	-	-	-	-
12	32540	Rights of Ways	-	99.0	-	-	-	-
13	33100	Production Gas Wells Equipment	-	99.0	-	-	-	-
14	33201	Field Lines	-	99.0	-	-	-	-
15	33202	Tributary Lines	-	99.0	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	-	99.0	-	-	-	-
17	33600	Purification Equipment	-	99.0	-	-	-	-
18								
19		Total Production Plant	-			0	0	0
20								
21		Storage Plant:						
22								
23	35010	Land	-	3.5	Storage (50/50)	-	-	-
24	35020	Rights of Way	4,200	3.5	Storage (50/50)	-	2,100	2,100
25	35100	Structures and Improvements	7,863	3.5	Storage (50/50)	-	3,931	3,931
26	35102	Compression Station Equipment	120,440	3.5	Storage (50/50)	-	60,220	60,220
27	35103	Meas. & Reg. Sta. Structues	20,864	3.5	Storage (50/50)	-	10,432	10,432
28	35104	Other Structures	106,003	3.5	Storage (50/50)	-	53,002	53,002
29	35200	Wells \ Rights of Way	2,463,749	3.5	Storage (50/50)	-	1,231,874	1,231,874
30	35201	Well Construction	1,502,528	3.5	Storage (50/50)	-	751,264	751,264
31	35202	Well Equipment	474,361	3.5	Storage (50/50)	-	237,180	237,180
32	35203	Cushion Gas	702,999	3.5	Storage (50/50)	-	351,499	351,499
33	35210	Leaseholds	167,328	3.5	Storage (50/50)	-	83,664	83,664
34	35211	Storage Rights	44,691	3.5	Storage (50/50)	-	22,346	22,346
35	35301	Field Lines	105,566	3.5	Storage (50/50)	-	52,783	52,783
36	35302	Tributary Lines	153,747	3.5	Storage (50/50)	-	76,873	76,873
37	35400	Compressor Station Equipment	682,172	3.5	Storage (50/50)	-	341,086	341,086
38	35500	Meas & Reg. Equipment	167,060	3.5	Storage (50/50)	-	83,530	83,530
39	35600	Purification Equipment	322,628	3.5	Storage (50/50)	-	161,314	161,314
40								
41		Total Storage Plant	7,046,197			0	3,523,099	3,523,099
42								
43		Transmission:						
44								
45	36510	Land & Land Rights	-	2.0	Demand	-	-	-
46	36520	Rights of Way	587,414	2.0	Demand	-	587,414	-
47	36602	Structures & Improvements	29,122	2.0	Demand	-	29,122	-
48	36603	Other Structues	62,894	2.0	Demand	-	62,894	-
49	36700	Mains Cathodic Protection	33,163	2.0	Demand	-	33,163	-
50	36701	Mains - Steel	18,044,112	2.0	Demand	-	18,044,112	-
51	36703	Mains - Anodes	11,180	2.0	Demand	-	11,180	-
52	36900	Meas. & Reg. Equipment	620,559	2.0	Demand	-	620,559	-
53	36901	Meas. & Reg. Equipment	2,023,747	2.0	Demand	-	2,023,747	-
54								
55		Total Transmission Plant	21,412,190			0	21,412,190	0
56								
57		Distribution:						
58								
59	37400	Land & Land Rights	-	4.0	Mains (All Demand)	-	-	-
60	37401	Land	-	4.0	Mains (All Demand)	-	-	-
61	37402	Land Rights	644,160	4.0	Mains (All Demand)	-	644,160	-
62	37403	Land Other	-	4.0	Mains (All Demand)	-	-	-
63	37500	Structures & Improvements	136,375	4.0	Mains (All Demand)	-	136,375	-
64	37501	Structures & Improvements T.B.	81,770	4.0	Mains (All Demand)	-	81,770	-
65	37502	Land Rights	40,711	4.0	Mains (All Demand)	-	40,711	-
66	37503	Improvements	2,204	4.0	Mains (All Demand)	-	2,204	-
67	37600	Mains Cathodic Protection	1,792,334	4.0	Mains (All Demand)	-	1,792,334	-
68	37601	Mains - Steel	30,950,942	4.0	Mains (All Demand)	-	30,950,942	-
69	37602	Mains - Plastic	28,052,270	4.0	Mains (All Demand)	-	28,052,270	-
70	37603	Mains - Anodes	1,851,162	4.0	Mains (All Demand)	-	1,851,162	-
71	37604	Mains - Leak Clamps	5,615,083	4.0	Mains (All Demand)	-	5,615,083	-
72	37800	Meas & Reg. Sta. Equip - General	5,288,177	4.0	Mains (All Demand)	-	5,288,177	-
73	37900	Meas & Reg. Sta. Equip - City Gate	1,456,651	4.0	Mains (All Demand)	-	1,456,651	-
74	37905	Meas & Reg. Sta. Equipment T.b.	1,068,358	4.0	Mains (All Demand)	-	1,068,358	-
75	38000	Services	38,828,841	1.0	Customer	38,828,841	-	-
76	38100	Meters	23,998,006	1.0	Customer	23,998,006	-	-
77	38200	Meter Installaitons	22,719,274	1.0	Customer	22,719,274	-	-
78	38300	House Regulators	469,350	1.0	Customer	469,350	-	-
79	38400	House Reg. Installations	130,024	1.0	Customer	130,024	-	-
80	38500	Ind. Meas. & Reg. Sta. Equipment	3,090,645	1.0	Customer	3,090,645	-	-
81	38600	Other Prop. On Cust. Prem	-	99.0	-	-	-	-
82								
83		Total Distribution Plant	166,216,337			89,236,139	76,980,198	0
84								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
85		General:						
86								
87	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
88	39000	Structures & Improvements	1,968,463	5.4	P, S, T & D Plant	702,419	1,225,047	40,996
89	39002	Structures - Brick	118,817	5.4	P, S, T & D Plant	42,398	73,944	2,475
90	39003	Improvements	335,075	5.4	P, S, T & D Plant	119,567	208,530	6,978
91	39003	Air Conditioning Equipment	8,916	5.4	P, S, T & D Plant	3,181	5,548	186
92	39004	Improvement to Leased Premises	1,267,195	5.4	P, S, T & D Plant	452,181	788,623	26,391
93	39009	Office Furniture & Equipment	1,473,706	5.4	P, S, T & D Plant	525,872	917,142	30,692
94	39100	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
95	39102	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
96	39103	Transportation Equipment	75,817	5.4	P, S, T & D Plant	27,054	47,184	1,579
97	39200	Trucks	-	5.4	P, S, T & D Plant	-	-	-
98	39201	Trailers	8,658	5.4	P, S, T & D Plant	3,089	5,388	180
99	39202	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
100	39400	Tools, Shop & Garage Equipment	3,345,740	5.4	P, S, T & D Plant	1,193,882	2,082,178	69,680
101	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
102	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
103	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
104	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
105	39700	Communication Equipment	366,653	5.4	P, S, T & D Plant	130,835	228,182	7,636
106	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
107	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
108	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
109	39800	Miscellaneous Equipment	1,548,948	5.4	P, S, T & D Plant	552,721	963,968	32,259
110	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
111	39901	Other Tangible Property - Servers - H/W	21,595	5.4	P, S, T & D Plant	7,706	13,439	450
112	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
113	39903	Other Tangible Property - Network - H/W	-	5.4	P, S, T & D Plant	-	-	-
114	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
115	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
116	39906	Other Tang. Property - PC Hardware	530,003	5.4	P, S, T & D Plant	189,125	329,841	11,038
117	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
118	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
119	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
120		Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
121		Retirement Work in Progress	(1,655,581)	5.4	P, S, T & D Plant	(590,771)	(1,030,329)	(34,480)
122		AR 15 general plant amortization	-	5.4	P, S, T & D Plant	-	-	-
123								
124		Total General Plant	9,414,005			3,359,260	5,858,685	196,061
125								
126		TOTAL DIRECT RESERVE FOR DEPRECIATION	204,216,911			92,641,139	107,853,944	3,721,829
127								
128		Kentucky Mid-States General Office:						
129								
130		Intangible Plant:						
131								
132	30100	Organization	-	5.4	P, S, T & D Plant	-	-	-
133	30200	Franchises & Consents	-	5.4	P, S, T & D Plant	-	-	-
134	30300	Misc Intangible Plant	-	5.4	P, S, T & D Plant	-	-	-
135								
136		Total Intangible Plant:	-			0	0	0
137								
138		General:						
139								
140	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
141	39001	Structures Frame	60,032	5.4	P, S, T & D Plant	21,422	37,360	1,250
142	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
143	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
144	39004	Air Conditioning Equipment	7,666	5.4	P, S, T & D Plant	2,735	4,771	160
145	39009	Improvement to leased Premises	19,405	5.4	P, S, T & D Plant	6,925	12,077	404
146	39100	Office Furniture & Equipment	4,261	5.4	P, S, T & D Plant	1,520	2,652	89
147	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
148	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
149	39200	Transportation Equipment	(990)	5.4	P, S, T & D Plant	(353)	(616)	(21)
150	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
151	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
152	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
153	39400	Tools, Shop & Garage Equipment	26,914	5.4	P, S, T & D Plant	9,604	16,750	561
154	39600	Power Operated Equipment	1,496	5.4	P, S, T & D Plant	534	931	31
155	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
156	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
157	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
158	39700	Communication Equipment	(11,027)	5.4	P, S, T & D Plant	(3,935)	(6,862)	(230)
159	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
160	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
161	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
162	39800	Miscellaneous Equipment	(63,459)	5.4	P, S, T & D Plant	(22,645)	(39,493)	(1,322)
163	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
164	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
165	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
166	39903	Other Tangible Property - Network - H/W	9,760	5.4	P, S, T & D Plant	3,483	6,074	203
167	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
168	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
169	39906	Other Tang. Property - PC Hardware	-	5.4	P, S, T & D Plant	-	-	-
170	39907	Other Tang. Property - PC Software	21,748	5.4	P, S, T & D Plant	7,760	13,535	453
171	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
172	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
173	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
174		Retirement Work in Progress	26,243	5.4	P, S, T & D Plant	9,364	16,332	547
175								
176		Total General Plant	102,049			36,415	63,509	2,125
177								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
178		Shared Services General Office:						
179								
180		General:						
181								
182	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
183	39000	Structures & Improvements	158,337	5.4	P, S, T & D Plant	56,501	98,539	3,298
184	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
185	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
186	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
187	39009	Improvement to leased Premises	496,454	5.4	P, S, T & D Plant	177,153	308,962	10,339
188	39100	Office Furniture & Equipment	193,036	5.4	P, S, T & D Plant	68,882	120,133	4,020
189	39102	Remittance Processing Equip	0	5.4	P, S, T & D Plant	0	0	0
190	39103	Office Machines	0	5.4	P, S, T & D Plant	0	0	0
191	39200	Transportation Equipment	10,393	5.4	P, S, T & D Plant	3,709	6,468	216
192	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
193	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
194	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
195	39400	Tools, Shop & Garage Equipment	1,267	5.4	P, S, T & D Plant	452	788	26
196	39500	39500-Laboratory Equipment	-	5.4	P, S, T & D Plant	-	-	-
197	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
198	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
199	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
200	39700	Communication Equipment	7,704	5.4	P, S, T & D Plant	2,749	4,795	160
201	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
202	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
203	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
204	39800	Miscellaneous Equipment	2,531	5.4	P, S, T & D Plant	903	1,575	53
205	39900	Other Tangible Property	(0)	5.4	P, S, T & D Plant	(0)	(0)	(0)
206	39901	Other Tangible Property - Servers - H/W	595,292	5.4	P, S, T & D Plant	212,422	370,472	12,398
207	39902	Other Tangible Property - Servers - S/W	703,290	5.4	P, S, T & D Plant	250,959	437,683	14,647
208	39903	Other Tangible Property - Network - H/W	95,736	5.4	P, S, T & D Plant	34,162	59,580	1,994
209	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
210	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
211	39906	Other Tang. Property - PC Hardware	86,835	5.4	P, S, T & D Plant	30,986	54,041	1,808
212	39907	Other Tang. Property - PC Software	3,178	5.4	P, S, T & D Plant	1,134	1,978	66
213	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
214	39909	Other Tang. Property - Application Software	4,933,686	5.4	P, S, T & D Plant	1,760,519	3,070,416	102,751
215	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
216	ADJ	WTW Adjustment	9,173	5.4	P, S, T & D Plant	3,273	5,708	191
217								
218		Total General Plant	7,296,912			2,603,804	4,541,139	151,969
219								
220		Shared Services Customer Support:						
221								
222		General:						
223								
224	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
225	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
226	36602	Structures & Improvements	420,763	5.4	P, S, T & D Plant	150,143	261,856	8,763
227	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
228	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
229	39009	Improvement to leased Premises	136,913	5.4	P, S, T & D Plant	48,855	85,206	2,851
230	39100	Office Furniture & Equipment	99,042	5.4	P, S, T & D Plant	35,342	61,638	2,063
231	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
232	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
233	39200	Transportation Equipment	2,251	5.4	P, S, T & D Plant	803	1,401	47
234	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
235	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
236	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
237	39400	Tools, Shop & Garage Equipment	10,609	5.4	P, S, T & D Plant	3,786	6,602	221
238	39500	Laboratory Equipment	4	5.4	P, S, T & D Plant	1	2	0
239	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
240	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
241	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
242	39700	Communication Equipment	98,184	5.4	P, S, T & D Plant	35,036	61,104	2,045
243	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
244	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
245	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
246	39800	Miscellaneous Equipment	10,096	5.4	P, S, T & D Plant	3,603	6,283	210
247	39900	Other Tangible Property	(8,317)	5.4	P, S, T & D Plant	(2,968)	(5,176)	(173)
248	39901	Other Tangible Property - Servers - H/W	208,015	5.4	P, S, T & D Plant	74,227	129,456	4,332
249	39902	Other Tangible Property - Servers - S/W	99,003	5.4	P, S, T & D Plant	35,328	61,613	2,062
250	39903	Other Tangible Property - Network - H/W	17,716	5.4	P, S, T & D Plant	6,322	11,025	369
251	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
252	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
253	39906	Other Tang. Property - PC Hardware	34,234	5.4	P, S, T & D Plant	12,216	21,305	713
254	39907	Other Tang. Property - PC Software	(3,876)	5.4	P, S, T & D Plant	(1,383)	(2,412)	(81)
255	39908	Other Tang. Property - Mainframe S/W	4,158,816	5.4	P, S, T & D Plant	1,484,017	2,588,185	86,614
256	39909	Other Tang. Property - Application Software	5,952	5.4	P, S, T & D Plant	2,124	3,704	124
257	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
258		Retirement Work in Progress	-	5.4	P, S, T & D Plant	-	-	-
259								
260		Total General Plant	5,289,404			1,887,452	3,291,792	110,160
261								
262		TOTAL RESERVE FOR DEPRECIATION	216,905,276			97,168,809	115,750,384	3,986,083

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF OTHER RATE BASE

		Test Year	Classif.	Classif.	Customer	Demand	Commodity
		$	Factor	Basis	$	$	$
1	Rate Base Additions:						
2							
3	Materials and Supplies - KY Direct	(29,510)	9.1	Allocated O&M Expenses	(1,810)	(6,064)	(21,636)
4	Materials and Supplies - KY Mid-States GO	549,932	9.1	Allocated O&M Expenses	33,722	113,001	403,209
5	Materials and Supplies - Shared Services GO	14,276	9.1	Allocated O&M Expenses	875	2,934	10,467
6	Materials and Supplies - Shared Services CS	0	9.1	Allocated O&M Expenses	-	-	-
7	Gas Storage Inventory	9,182,907	3.0	Commodity	-	-	9,182,907
8	Prepayments - KY Direct	0	9.1	Allocated O&M Expenses	-	-	-
9	Prepayments - KY Mid-States GO	0	9.1	Allocated O&M Expenses	-	-	-
10	Prepayments - Shared Services GO	0	9.1	Allocated O&M Expenses	-	-	-
11	Prepayments - Shared Services CS	0	9.1	Allocated O&M Expenses	-	-	-
12	Cash Working Capital	(2,199,566)	9.1	Allocated O&M Expenses	(134,880)	(451,970)	(1,612,716)
13	Regulatory Assets/Liabilities	(3,720,791)	9.1	Allocated O&M Expenses	(228,163)	(764,553)	(2,728,075)
14							
15	Total Rate Base Additions	3,797,249			(330,255)	(1,106,652)	5,234,156
16							
17							
18	Rate Base Deductions:						
19							
20	Customer Advances - KY Direct	(736,136)	1.0	Customer	(736,136)	-	-
21	Customer Advances - KY Mid-States GO	0	1.0	Customer	-	-	-
22	Customer Advances - Shared Services GO	0	1.0	Customer	-	-	-
23	Customer Advances - Shared Services CS	0	1.0	Customer	-	-	-
24	ADIT - KY Direct (Div 009)	(94,613,910)	5.7	Net Plant	(31,213,046)	(61,361,892)	(2,038,972)
25	ADIT - Shared Services GO (Div 002)	(7,615,553)	5.7	Net Plant	(2,512,364)	(4,939,070)	(164,119)
26	ADIT - Shared Services CS (Div 012)	(492,256)	5.7	Net Plant	(162,395)	(319,253)	(10,608)
27	ADIT - KY Mid-States GO (Div 091)	(184,730)	5.7	Net Plant	(60,942)	(119,807)	(3,981)
28	Change in Net Operating Loss Carryforward	(5,815,333)	5.7	Net Plant	(1,918,473)	(3,771,537)	(125,323)
29							
30	Total Rate Base Deductions	(109,457,919)			(36,603,357)	(70,511,559)	(2,343,003)
31							
32							
33	TOTAL OTHER RB	(105,660,670)			(36,933,611)	(71,618,211)	2,891,152
34							
35	Interest on Customer Deposits	0	1.0	Customer	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF O&M EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Production & Gathering:						
2		Operation						
3	7500	Op., Sup., & Eng.	0	99.0	-	-	-	-
4	7510	Production Maps & Records	0	99.0	-	-	-	-
5	7530	Field Lines Expenses	0	99.0	-	-	-	-
6	7540	Field Compressor Station Expense	0	99.0	-	-	-	-
7	7550	Field Compressor Sta. Fuel & Pwr.	0	99.0	-	-	-	-
8	7560	Field Meas. & Regul. Station Exp	0	99.0	-	-	-	-
9	7570	Purification Expense	0	99.0	-	-	-	-
10	7590	Other Expenses	0	99.0	-	-	-	-
11		Maintenance						
12	7610	Maint. Sup., & Eng.	0	99.0	-	-	-	-
13	7620	Structures and Improvements	0	99.0	-	-	-	-
14	7640	Field Line Maintenance	0	99.0	-	-	-	-
15	7650	Compressor Station Equip. Maint.	0	99.0	-	-	-	-
16	7660	Meas. & Regul. Station Equip Maint	0	99.0	-	-	-	-
17	7670	Purification Equipment Maintenance	0	99.0	-	-	-	-
18	7680	Other Equipment Maintenance	0	99.0	-	-	-	-
19	7690	Gas Processed By Others	0	99.0	-	-	-	-
20		Total Production & Gathering	0			0	0	0
21								
22		Other Gas Supply Expenses:						
23		Operation						
24	8001	Intercompany Gas Well-head Purchases	0	3.0	Commodity	-	-	-
25	8010	Natural gas field line purchases	115,617	3.0	Commodity	-	-	115,617
26	8040	Natural gas city gate purchases	50,226,537	3.0	Commodity	-	-	50,226,537
27	8050	Transmission-Operation supervision and engineering	(29,531)	3.0	Commodity	-	-	(29,531)
28	8051	Other Gas Purchases / Gas Cost Adjustments	53,391,020	3.0	Commodity	-	-	53,391,020
29	8052	PGA for Commercial	30,150,016	3.0	Commodity	-	-	30,150,016
30	8053	PGA for Industrial	4,872,096	3.0	Commodity	-	-	4,872,096
31	8054	PGA for Public Authority	4,999,866	3.0	Commodity	-	-	4,999,866
32	8058	Unbilled PGA Cost	(5,763,929)	3.0	Commodity	-	-	(5,763,929)
33	8059	PGA Offset to Unrecovered Gas Cost	(109,657,357)	3.0	Commodity	-	-	(109,657,357)
34	8060	Exchange gas	(122,035)	3.0	Commodity	-	-	(122,035)
35	8081	Gas withdrawn from storage-Debit	30,798,939	3.0	Commodity	-	-	30,798,939
36	8082	Gas delivered to storage-Credit	(14,414,625)	3.0	Commodity	-	-	(14,414,625)
37	8120	Gas used for other utility operations-Credit	(8,172)	3.0	Commodity	-	-	(8,172)
38	8580	Transmission and compression of gas by others	43,082,454	3.0	Commodity	-	-	43,082,454
39		Maintenance						
40	8350	Maint. Of Purch. Gas Meas. Sta.	0	3.0	Commodity	-	-	-
41		Total Other Gas Supply Expenses	87,640,898			0	0	87,640,898
42								
43		Underground Storage:						
44		Operation						
45	8140	Storage-Operation supervision and engineering	0	3.5	Storage (50/50)	-	-	-
46	8160	Wells expenses	35,164	3.5	Storage (50/50)	-	17,582	17,582
47	8170	Lines expenses	22,782	3.5	Storage (50/50)	-	11,391	11,391
48	8180	Compressor station expenses	44,776	3.5	Storage (50/50)	-	22,388	22,388
49	8190	Compressor station fuel and power	0	3.5	Storage (50/50)	-	-	-
50	8200	Storage-Measuring and regulating station expenses	9,536	3.5	Storage (50/50)	-	4,768	4,768
51	8210	Storage-Purification expenses	83,940	3.5	Storage (50/50)	-	41,970	41,970
52	8240	Storage-Other expenses	0	3.5	Storage (50/50)	-	-	-
53	8250	Storage well royalties	10,482	3.5	Storage (50/50)	-	5,241	5,241
54	8260	Rents	0	3.5	Storage (50/50)	-	-	-
55		Maintenance						
56	8300	Maint. Sup., & Eng.	0	3.5	Storage (50/50)	-	-	-
57	8310	Structures and Improvements	0	3.5	Storage (50/50)	-	-	-
58	8320	Reservoirs & Wells Maintenance	0	3.5	Storage (50/50)	-	-	-
59	8330	Line Maintenance	0	3.5	Storage (50/50)	-	-	-
60	8340	Compressor Station Equip Maint	46,416	3.5	Storage (50/50)	-	23,208	23,208
61	8350	Meas. & Regul. Station Equip Maint	0	3.5	Storage (50/50)	-	-	-
62	8360	Purification Equipment Maintenance	0	3.5	Storage (50/50)	-	-	-
63	8410	Other storage expenses-Operation labor and expenses	233,243	3.5	Storage (50/50)	-	116,621	116,621
64		Total Underground Storage Expense	486,338			0	243,169	243,169
65								
66		Transmission:						
67		Operation						
68	8500	Op., Sup., & Eng.	0	2.0	Demand	-	-	-
69	8510	System Control & Load Dispatching	0	2.0	Demand	-	-	-
70	8520	Communication Systems Expense	0	2.0	Demand	-	-	-
71	8530	Compressor Station Labor Expense	0	2.0	Demand	-	-	-
72	8540	Compressor Station Fuel Gas	0	2.0	Demand	-	-	-
73	8550	Compressor Station Fuel & Power	488	2.0	Demand	-	488	-
74	8560	Mains Expense	145,499	2.0	Demand	-	145,499	-
75	8570	Meas. & Regul. Station Expenses	11,936	2.0	Demand	-	11,936	-
76	8580	LDC Payment	0	2.0	Demand	-	-	-
77	8580	LDC Payment - A&G	0	2.0	Demand	-	-	-
78	8590	Other Expenses	0	2.0	Demand	-	-	-
79	8600	Rents	0	2.0	Demand	-	-	-
80		Maintenance						
81	8610	Maint. Sup., & Eng.	0	2.0	Demand	-	-	-
82	8620	Structures and Improvements	0	2.0	Demand	-	-	-
83	8630	Mains	22,915	2.0	Demand	-	22,915	-
84	8640	Compressor Station Equip Maint	0	2.0	Demand	-	-	-
85	8650	Meas. & Regul. Station Equip Maint	0	2.0	Demand	-	-	-
86	8660	Communication Equipment Maintenance	0	2.0	Demand	-	-	-
87	8670	Other Equipment Maintenance	0	2.0	Demand	-	-	-
88		Total Transmission Expense	180,838			0	180,838	0
89								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF O&M EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
90		Distribution:						
91		Operation						
92	8700	Supervision and Engineering	2,140,705	10.0	Composite of Accts. 871-879 & 886-893	211,070	1,868,213	61,423
93	8710	Distribution Load Dispatching	(41)	3.0	Commodity	-	-	(41)
94	8711	Odorization	132,819	3.0	Commodity	-	-	132,819
94	8720	Compressor Station Labor & Expenses	0	3.0	Commodity	-	-	-
95	8740	Mains & Services	6,802,984	12.0	Composite of Accts. 374-379	-	6,802,984	-
96	8750	Measuring and Regulating Station Exp. - Gen	1,361,535	12.0	Composite of Accts. 374-379	-	1,361,535	-
97	8760	Measuring and Regulating Station Exp. - Ind.	523	1.0	Customer	523	-	-
98	8770	Measuring and Regulating Sta. Exp. - City Gate	5,487	12.0	Composite of Accts. 374-379	-	5,487	-
99	8780	Meters and House Regulator Expense	938,471	1.0	Customer	938,471	-	-
100	8790	Customer Installations Expense	257	1.0	Customer	257	-	-
101	8800	Other Expense	3,085	10.0	Composite of Accts. 871-879 & 886-893	304	2,692	89
102	8810	Rents	75,023	10.0	Composite of Accts. 871-879 & 886-893	7,397	65,473	2,153
103		Maintenance						
104	8850	Maintenance Supervision and Engineering	0	10.0	Composite of Accts. 871-879 & 886-893	-	-	-
105	8860	Maintenance of Structures and Improvements	0	12.0	Composite of Accts. 374-379	-	-	-
106	8870	Maintenance of Mains	144,480	12.0	Composite of Accts. 374-379	-	144,480	-
107	8890	Maintenance of compressor station equipment	140,590	3.0	Commodity	-	-	140,590
108	8900	Maint. of Measuring and Regulating Station Equip. - General	0	12.0	Composite of Accts. 374-379	-	-	-
109	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	135	1.0	Customer	135	-	-
110	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	178	12.0	Composite of Accts. 374-379	-	178	-
111	8930	Maintenance of Services	0	1.0	Customer	-	-	-
112	8940	Maintenance of Meters and House Regulators	0	1.0	Customer	-	-	-
113	8950	Maintenance of Other Equipment	0	10.0	Composite of Accts. 871-879 & 886-893	-	-	-
114		Total Distribution	11,746,231			1,158,157	10,251,043	337,032
115								
116		Customer Accounts:						
117	9010	Supervision	0	1.0	Customer	-	-	-
118	9020	Meter Reading Expense	735,288	1.0	Customer	735,288	-	-
119	9030	Customer Records and Collection Expenses	1,067,803	1.0	Customer	1,067,803	-	-
120	9040	Uncollectible Accounts	731,532	1.0	Customer	731,532	-	-
121	9050	Miscellaneous Customer Accounts Expenses	0	1.0	Customer	-	-	-
122		Total Customer Accounts	2,534,624			2,534,624	0	0
123								
124		Customer Service and Information:						
125	9070	Supervision	0	1.0	Customer	-	-	-
126	9080	Customer Assistance Expenses	0	1.0	Customer	-	-	-
127	9090	Informational and Instructional Advertising Expenses	214,461	1.0	Customer	214,461	-	-
128	9100	Miscellaneous Customer Service and Informational Expenses	0	1.0	Customer	-	-	-
129		Total Customer Service and Information	214,461			214,461	0	0
130								
131		Sales:						
132	9110	Supervision	158,549	1.0	Customer	158,549	-	-
133	9120	Demonstrating and Selling Expenses	77,078	1.0	Customer	77,078	-	-
134	9130	Advertising Expenses	36,821	1.0	Customer	36,821	-	-
135	9160	Miscellaneous Sales Expenses	(188,721)	1.0	Customer	(188,721)	-	-
136		Total Sales	83,728			83,728	0	0
137								
138		Administrative & General:						
139		Operation						
140	9200	Administrative and General Salaries	-	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	-	-	-
141	9210	Office Supplies and Expenses	69,069	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	12,576	54,695	1,798
142	9220	Administrative Expenses Transferred - Customer Support	-	1.0	Customer	-	-	-
143	9220	Administrative Expenses Transferred - General	18,251,309	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	3,323,172	14,452,956	475,181
144	9230	Outside Services Employed	69,993	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	12,744	55,426	1,822
145	9240	Property Insurance	-	5.7	Net Plant	-	-	-
146	9250	Injuries and Damages	23,257	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	4,235	18,417	606
147	9260	Employee Pensions and Benefits	872,759	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	158,911	691,125	22,723
148	9270	Franchise Requirements	635	1.0	Customer	635	-	-
149	9280	Regulatory Commission Expenses	165,392	1.0	Customer	165,392	-	-
150	930.1	General Advertising Expenses	-	1.0	Customer	-	-	-
151	930.2	Miscellaneous General Expense	24,411	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	4,445	19,331	636
152	ADJ	Adjustments	(1,404,321)	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	(255,697)	(1,112,062)	(36,562)
153		Maintenance						
154	9320	Maintenance of General Plant	0	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	-	-	-
155		Total A&G	18,072,504			3,426,413	14,179,888	466,203
156								
157		TOTAL O&M EXPENSE	120,959,622			7,417,382	24,854,938	88,687,302

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Intangible Plant:						
2								
3	30100	Organization	-	99.0	-	-	-	-
4	30200	Franchises & Consents	-	99.0	-	-	-	-
5	30300	Misc Intangible Plant	-	99.0	-	-	-	-
6								
7		Total Intangible Plant:	0			0	0	0
8								
9		Production Plant:						
10								
11	32520	Producing Leaseholds	-	99.0	-	-	-	-
12	32540	Rights of Ways	-	99.0	-	-	-	-
13	33100	Production Gas Wells Equipment	-	99.0	-	-	-	-
14	33201	Field Lines	-	99.0	-	-	-	-
15	33202	Tributary Lines	-	99.0	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	-	99.0	-	-	-	-
17	33600	Purification Equipment	-	99.0	-	-	-	-
18								
19		Total Production Plant	0			0	0	0
20								
21		Storage Plant:						
22								
23	35010	Land	-	3.5	Storage (50/50)	-	-	-
24	35020	Rights of Way	32	3.5	Storage (50/50)	-	16	16
25	35100	Structures and Improvements	294	3.5	Storage (50/50)	-	147	147
26	35102	Compression Station Equipment	3,062	3.5	Storage (50/50)	-	1,531	1,531
27	35103	Meas. & Reg. Sta. Structues	255	3.5	Storage (50/50)	-	127	127
28	35104	Other Structures	1,897	3.5	Storage (50/50)	-	948	948
29	35200	Wells \ Rights of Way	241,977	3.5	Storage (50/50)	-	120,988	120,988
30	35201	Well Construction	27,200	3.5	Storage (50/50)	-	13,600	13,600
31	35202	Well Equipment	9,210	3.5	Storage (50/50)	-	4,605	4,605
32	35203	Cushion Gas	23,728	3.5	Storage (50/50)	-	11,864	11,864
33	35210	Leaseholds	1,000	3.5	Storage (50/50)	-	500	500
34	35211	Storage Rights	557	3.5	Storage (50/50)	-	279	279
35	35301	Field Lines	2,209	3.5	Storage (50/50)	-	1,105	1,105
36	35302	Tributary Lines	2,637	3.5	Storage (50/50)	-	1,319	1,319
37	35400	Compressor Station Equipment	308,927	3.5	Storage (50/50)	-	154,463	154,463
38	35500	Meas & Reg. Equipment	5,107	3.5	Storage (50/50)	-	2,553	2,553
39	35600	Purification Equipment	33,187	3.5	Storage (50/50)	-	16,594	16,594
40								
41		Total Storage Plant	661,278			0	330,639	330,639
42								
43		Transmission:						
44								
45	36510	Land & Land Rights	-	2.0	Demand	-	-	-
46	36520	Rights of Way	7,376	2.0	Demand	-	7,376	-
47	36602	Structures & Improvements	4,496	2.0	Demand	-	4,496	-
48	36603	Other Structues	-	2.0	Demand	-	-	-
49	36700	Mains Cathodic Protection	1,478	2.0	Demand	-	1,478	-
50	36701	Mains - Steel	384,012	2.0	Demand	-	384,012	-
51	36703	Mains - Anodes	-	2.0	Demand	-	-	-
52	36900	Meas. & Reg. Equipment	35,793	2.0	Demand	-	35,793	-
53	36901	Meas. & Reg. Equipment	40,624	2.0	Demand	-	40,624	-
54								
55		Total Transmission Plant	473,778			0	473,778	0
56								
57		Distribution:						
58								
59	37400	Land & Land Rights	-	4.0	Mains (All Demand)	-	-	-
60	37401	Land	-	4.0	Mains (All Demand)	-	-	-
61	37402	Land Rights	54,464	4.0	Mains (All Demand)	-	54,464	-
62	37403	Land Other	-	4.0	Mains (All Demand)	-	-	-
63	37500	Structures & Improvements	4,841	4.0	Mains (All Demand)	-	4,841	-
64	37501	Structures & Improvements T.B.	1,437	4.0	Mains (All Demand)	-	1,437	-
65	37502	Land Rights	666	4.0	Mains (All Demand)	-	666	-
66	37503	Improvements	58	4.0	Mains (All Demand)	-	58	-
67	37600	Mains Cathodic Protection	159,292	4.0	Mains (All Demand)	-	159,292	-
68	37601	Mains - Steel	3,554,207	4.0	Mains (All Demand)	-	3,554,207	-
69	37602	Mains - Plastic	3,416,357	4.0	Mains (All Demand)	-	3,416,357	-
70	37603	Mains - Anodes	200,720	4.0	Mains (All Demand)	-	200,720	-
71	37604	Mains - Leak Clamps	339,494	4.0	Mains (All Demand)	-	339,494	-
72	37800	Meas & Reg. Sta. Equip - General	573,607	4.0	Mains (All Demand)	-	573,607	-
73	37900	Meas & Reg. Sta. Equip - City Gate	214,735	4.0	Mains (All Demand)	-	214,735	-
74	37905	Meas & Reg. Sta. Equipment T.b.	37,287	4.0	Mains (All Demand)	-	37,287	-
75	38000	Services	4,814,131	1.0	Customer	4,814,131	-	-
76	38100	Meters	2,722,922	1.0	Customer	2,722,922	-	-
77	38200	Meter Installaitons	2,026,363	1.0	Customer	2,026,363	-	-
78	38300	House Regulators	124,799	1.0	Customer	124,799	-	-
79	38400	House Reg. Installations	12,401	1.0	Customer	12,401	-	-
80	38500	Ind. Meas. & Reg. Sta. Equipment	97,340	1.0	Customer	97,340	-	-
81	38600	Other Prop. On Cust. Prem	-	99.0	-	-	-	-
82								
83		Total Distribution Plant	18,355,122			9,797,957	8,557,165	0
84								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
85		General:						
86								
87	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
88	39000	Structures & Improvements	225,186	5.4	P, S, T & D Plant	80,355	140,142	4,690
89	39001	Structures - Brick	4,207	5.4	P, S, T & D Plant	1,501	2,618	88
90	39002	Improvements	21,302	5.4	P, S, T & D Plant	7,601	13,257	444
91	39003	Air Conditioning Equipment	553	5.4	P, S, T & D Plant	197	344	12
92	39004	Improvement to leased Premises	-	5.4	P, S, T & D Plant	-	-	-
93	39009	Office Furniture & Equipment	90,847	5.4	P, S, T & D Plant	32,417	56,537	1,892
94	39100	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
95	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
96	39200	Transportation Equipment	2,511	5.4	P, S, T & D Plant	896	1,563	52
97	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
98	39202	Trailers	508	5.4	P, S, T & D Plant	181	316	11
99	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
100	39400	Tools, Shop & Garage Equipment	169,362	5.4	P, S, T & D Plant	60,435	105,400	3,527
101	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
102	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
103	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
104	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
105	39700	Communication Equipment	28,944	5.4	P, S, T & D Plant	10,328	18,013	603
106	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
107	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
108	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
109	39800	Miscellaneous Equipment	199,380	5.4	P, S, T & D Plant	71,146	124,082	4,152
110	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
111	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
112	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
113	39903	Other Tangible Property - Network - H/W	-	5.4	P, S, T & D Plant	-	-	-
114	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
115	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
116	39906	Other Tang. Property - PC Hardware	11,055	5.4	P, S, T & D Plant	3,945	6,880	230
117	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
118	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
119	39908	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
120	40600	Amortization of gas plant acquisition adjustments	49,305	5.4	P, S, T & D Plant	17,594	30,684	1,027
121								
122								
123		Total General Plant	803,161			286,597	499,837	16,727
124								
125		TOTAL DIRECT DEPRECIATION EXPENSE	20,293,339			10,084,554	9,861,419	347,366
126								
127		Kentucky Mid-States General Office:						
128								
129		Intangible Plant:						
130								
131	30100	Organization	-	5.4	P, S, T & D Plant	-	-	-
132	30200	Franchises & Consents	-	5.4	P, S, T & D Plant	-	-	-
133	30300	Misc Intangible Plant	-	5.4	P, S, T & D Plant	-	-	-
134								
135		Total Intangible Plant:	0			0	0	0
136								
137		General:						
138								
139	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
140	39001	Structures Frame	3,943	5.4	P, S, T & D Plant	1,407	2,454	82
141	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
142	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
143	39004	Air Conditioning Equipment	156	5.4	P, S, T & D Plant	56	97	3
144	39009	Improvement to leased Premises	-	5.4	P, S, T & D Plant	-	-	-
145	39100	Office Furniture & Equipment	865	5.4	P, S, T & D Plant	309	538	18
146	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
147	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
148	39200	Transportation Equipment	62	5.4	P, S, T & D Plant	22	38	1
149	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
150	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
151	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
152	39400	Tools, Shop & Garage Equipment	1,400	5.4	P, S, T & D Plant	500	871	29
153	39600	Power Operated Equipment	10	5.4	P, S, T & D Plant	4	6	0
154	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
155	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
156	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
157	39700	Communication Equipment	-	5.4	P, S, T & D Plant	-	-	-
158	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
159	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
160	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
161	39800	Miscellaneous Equipment	-	5.4	P, S, T & D Plant	-	-	-
162	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
163	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
164	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
165	39903	Other Tangible Property - Network - H/W	1,552	5.4	P, S, T & D Plant	554	966	32
166	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
167	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
168	39906	Other Tang. Property - PC Hardware	-	5.4	P, S, T & D Plant	-	-	-
169	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
170	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
171	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
172	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
173								
174								
175		Total General Plant	7,989			2,851	4,972	166

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
176								
177		Shared Services General Office:						
178								
179		General:						
180								
181	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
182	39000	Structures & Improvements	11,489	5.4	P, S, T & D Plant	4,100	7,150	239
183	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
184	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
185	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
186	39009	Improvement to leased Premises	28,706	5.4	P, S, T & D Plant	10,243	17,865	598
187	39100	Office Furniture & Equipment	24,600	5.4	P, S, T & D Plant	8,778	15,310	512
188	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
189	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
190	39200	Transportation Equipment	948	5.4	P, S, T & D Plant	338	590	20
191	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
192	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
193	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
194	39400	Tools, Shop & Garage Equipment	171	5.4	P, S, T & D Plant	61	106	4
195	39500	Laboratory Equipment	-	5.4	P, S, T & D Plant	-	-	-
196	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
197	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
198	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
199	39700	Communication Equipment	2,242	5.4	P, S, T & D Plant	800	1,395	47
200	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
201	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
202	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
203	39800	Miscellaneous Equipment	386	5.4	P, S, T & D Plant	138	240	8
204	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
205	39901	Other Tangible Property - Servers - H/W	336,969	5.4	P, S, T & D Plant	120,243	209,709	7,018
206	39902	Other Tangible Property - Servers - S/W	221,166	5.4	P, S, T & D Plant	78,920	137,640	4,606
207	39903	Other Tangible Property - Network - H/W	33,165	5.4	P, S, T & D Plant	11,835	20,640	691
208	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
209	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
210	39906	Other Tang. Property - PC Hardware	42,815	5.4	P, S, T & D Plant	15,278	26,646	892
211	39907	Other Tang. Property - PC Software	440	5.4	P, S, T & D Plant	157	274	9
212	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
213	39909	Other Tang. Property - Application Software	510,816	5.4	P, S, T & D Plant	182,278	317,900	10,639
214	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
215	ADJ	WTW Adjustment	(8,467)	5.4	P, S, T & D Plant	(3,021)	(5,269)	(176)
216								
217		Total General Plant	1,205,447			430,147	750,194	25,105
218								
219		Shared Services Customer Support:						
220								
221		General:						
222								
223	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
224	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
225	36602	Structures & Improvements	26,371	5.4	P, S, T & D Plant	9,410	16,412	549
226	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
227	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
228	39009	Improvement to leased Premises	7,572	5.4	P, S, T & D Plant	2,702	4,712	158
229	39100	Office Furniture & Equipment	11,237	5.4	P, S, T & D Plant	4,010	6,993	234
230	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
231	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
232	39200	Transportation Equipment	-	5.4	P, S, T & D Plant	-	-	-
233	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
234	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
235	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
236	39500	Laboratory Equipment	2,649	5.4	P, S, T & D Plant	945	1,649	55
237	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
238	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
239	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
240	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
241	39700	Communication Equipment	6,715	5.4	P, S, T & D Plant	2,396	4,179	140
242	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
243	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
244	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
245	39800	Miscellaneous Equipment	2,101	5.4	P, S, T & D Plant	750	1,307	44
246	39900	Other Tangible Property	1,186	5.4	P, S, T & D Plant	423	738	25
247	39901	Other Tangible Property - Servers - H/W	38,567	5.4	P, S, T & D Plant	13,762	24,002	803
248	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
249	39903	Other Tangible Property - Network - H/W	4,009	5.4	P, S, T & D Plant	1,431	2,495	83
250	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
251	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
252	39906	Other Tang. Property - PC Hardware	18,676	5.4	P, S, T & D Plant	6,664	11,623	389
253	39907	Other Tang. Property - PC Software	11	5.4	P, S, T & D Plant	4	7	0
254	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
255	39909	Other Tang. Property - Application Software	402,314	5.4	P, S, T & D Plant	143,560	250,375	8,379
256	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
257								
258								
259		Total General Plant	521,409			186,058	324,492	10,859
260								
261	NTB	To Match Schedule C-1	192.03	5.4	P, S, T & D Plant	69	120	4
262								
263		TOTAL DEPRECIATION EXPENSE	22,028,375			10,703,678	10,941,196	383,501

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

		Test Year	Classif.	Classif.	Customer	Demand	Commodity
		$	Factor	Basis	$	$	$
1	Taxes Other Than Income						
2							
3	Non Revenue Related:						
4	Payroll Related	375,952	9.1	Allocated O&M Expenses	23,054	77,251	275,647
5	Property Related	12,386,174	5.4	P, S, T & D Plant	4,419,838	7,708,375	257,961
6	DOT Transmission User Tax	232,790	9.1	Allocated O&M Expenses	14,275	47,834	170,681
7	Other	444,432	9.1	Allocated O&M Expenses	27,253	91,322	325,857
8	Total Non Revenue Related:	13,439,348			4,484,419	7,924,783	1,030,146
9							
10	Revenue Related:						
11	State Gross Receipts - Tax	0	99.0	-	-	-	-
12	Local Gross Receipts - Tax	0	99.0	-	-	-	-
13	Public Service Commission Assessment	291,875	3.0	Commodity	-	-	291,875
14	Total Revenue Related:	291,875			0	0	291,875
15							
16	Total Taxes, Other Than Income	13,731,224			4,484,419	7,924,783	1,322,021
17							
18							
19	Interest Expense	10,240,350	13.0	Rate Base	3,344,439	6,590,984	304,927
20							
21	Amortization of COS and Depreciation Reserves	(2,188,517)	18.0	Total Cost of Service at Equalized ROR	(434,546)	(848,250)	(905,722)
22							
23	Amortization of Excess ADIT	(189,998)	18.0	Total Cost of Service at Equalized ROR	(37,725)	(73,641)	(78,631)

Atmos Energy Corporation, Kentucky/Mid-States Division							
Class Cost of Service - Demand - Only Study							
Forecasted Test Period: Twelve Months Ended March 31, 2026							
SUMMARY OF CLASSIFICATION							
1							
2							
3							
4		Test Year	Classif.	Classif.	Customer	Demand	Commodity
5		$	Factor	Basis	$	$	$
6							
7	Operating Revenues	187,822,013			32,763,472	63,739,570	91,318,971
8							
9	Operating Expenses:						
10							
11	Operating & Maintenance	120,959,622			7,417,382	24,854,938	88,687,302
12	Depreciation & Amortization	22,028,375			10,703,678	10,941,196	383,501
13	Taxes Other Than Income	13,731,224			4,484,419	7,924,783	1,322,021
14							
15	Total Operating Expenses	156,719,221			22,605,479	43,720,917	90,392,824
16							
17	Income Before Taxes	31,102,792			10,157,992	20,018,653	926,147
18							
19	Interest Expense	10,240,350			3,344,439	6,590,984	304,927
20							
21	Income Taxes:						
22							
23	State Income Taxes	1,043,122	5.00%		340,678	671,383	31,061
24	Federal Income Taxes	4,162,057	21.00%		1,359,304	2,678,820	123,934
25	Total Deferred Income Taxes	0			0	0	0
26	Amortization of ITC	0			0	0	0
27							
28	Total Income Taxes	5,205,179			1,699,981	3,350,203	154,995
29							
30	Net Income	25,897,613			8,458,011	16,668,450	771,153
31							
32	Total Rate Base	628,233,491			205,177,426	404,349,163	18,706,901
33							
34	Rate of Return	4.1223%			4.1223%	4.1223%	4.1223%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Intangible Plant:								
2										
3	30100	Organization	6.2	P, S, T & D Plant - Customer	2,972	2,376	572	1	15	9
4	30200	Franchises & Consents	6.2	P, S, T & D Plant - Customer	42,768	34,182	8,230	16	212	128
5	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
6										
7		Total Intangible Plant:			45,740	36,558	8,802	17	227	137
8										
9		Production Plant:								
10										
11	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
12	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
13	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
14	33201	Field Lines	99.0	-	0	-	-	-	-	-
15	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
17	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
18										
19		Total Production Plant			0	0	0	0	0	0
20										
21		Storage Plant:								
22										
23	35010	Land	99.0	-	0	-	-	-	-	-
24	35020	Rights of Way	99.0	-	0	-	-	-	-	-
25	35100	Structures and Improvements	99.0	-	0	-	-	-	-	-
26	35102	Compression Station Equipment	99.0	-	0	-	-	-	-	-
27	35103	Meas. & Reg. Sta. Structues	99.0	-	0	-	-	-	-	-
28	35104	Other Structures	99.0	-	0	-	-	-	-	-
29	35200	Wells \ Rights of Way	99.0	-	0	-	-	-	-	-
30	35201	Well Construction	99.0	-	0	-	-	-	-	-
31	35202	Well Equipment	99.0	-	0	-	-	-	-	-
32	35203	Cushion Gas	99.0	-	0	-	-	-	-	-
33	35210	Leaseholds	99.0	-	0	-	-	-	-	-
34	35211	Storage Rights	99.0	-	0	-	-	-	-	-
35	35301	Field Lines	99.0	-	0	-	-	-	-	-
36	35302	Tributary Lines	99.0	-	0	-	-	-	-	-
37	35400	Compressor Station Equipment	99.0	-	0	-	-	-	-	-
38	35500	Meas & Reg. Equipment	99.0	-	0	-	-	-	-	-
39	35600	Purification Equipment	99.0	-	0	-	-	-	-	-
40										
41		Total Storage Plant			0	0	0	0	0	0
42										
43		Transmission:								
44										
45	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
46	36520	Rights of Way	99.0	-	0	-	-	-	-	-
47	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
48	36603	Other Structues	99.0	-	0	-	-	-	-	-
49	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
50	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
51	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
52	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
53	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
54										
55		Total Transmission Plant			0	0	0	0	0	0
56										
57		Distribution:								
58										
59	37400	Land & Land Rights	2.0	Bills	0	-	-	-	-	-
60	37401	Land	2.0	Bills	0	-	-	-	-	-
61	37402	Land Rights	2.0	Bills	0	-	-	-	-	-
62	37403	Land Other	2.0	Bills	0	-	-	-	-	-
63	37500	Structures & Improvements	2.0	Bills	0	-	-	-	-	-
64	37501	Structures & Improvements T.B.	2.0	Bills	0	-	-	-	-	-
65	37502	Land Rights	2.0	Bills	0	-	-	-	-	-
66	37503	Improvements	2.0	Bills	0	-	-	-	-	-
67	37600	Mains Cathodic Protection	2.0	Bills	0	-	-	-	-	-
68	37601	Mains - Steel	2.0	Bills	0	-	-	-	-	-
69	37602	Mains - Plastic	2.0	Bills	0	-	-	-	-	-
70	37603	Mains - Anodes	2.0	Bills	0	-	-	-	-	-
71	37604	Mains - Leak Clamps	2.0	Bills	0	-	-	-	-	-
72	37800	Meas & Reg. Sta. Equip - General	2.0	Bills	0	-	-	-	-	-
73	37900	Meas & Reg. Sta. Equip - City Gate	2.0	Bills	0	-	-	-	-	-
74	37905	Meas & Reg. Sta. Equipment T.b.	2.0	Bills	0	-	-	-	-	-
75	38000	Services	2.0	Bills	193,916,542	172,131,494	21,572,990	9,386	126,507	76,164
76	38100	Meters	4.0	Meter Investment	55,920,540	38,934,861	15,880,938	48,900	659,055	396,787
77	38200	Meter Installaitons	4.0	Meter Investment	61,761,518	43,001,661	17,539,724	54,007	727,894	438,232
78	38300	House Regulators	4.0	Meter Investment	3,974,497	2,767,256	1,128,722	3,476	46,842	28,201
79	38400	House Reg. Installations	4.0	Meter Investment	378,094	263,249	107,375	331	4,456	2,683
80	38500	Ind. Meas. & Reg. Sta. Equipment	2.2	Non-Residential Bills	5,725,878	-	5,670,142	2,467	33,251	20,019
81	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
82										
83		Total Distribution Plant			321,677,069	257,098,521	61,899,891	118,567	1,598,004	962,086

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF PLANT IN SERVICE											
84											
85		General:									
86											
87	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	432,378	345,575	83,202	159	2,148	1,293	
88	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	3,303,222	2,640,081	635,635	1,218	16,410	9,879	
89	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
90	39002	Structures-Brick	6.2	P, S, T & D Plant - Customer	61,774	49,372	11,887	23	307	185	
91	39003	Improvements	6.2	P, S, T & D Plant - Customer	312,815	250,016	60,195	115	1,554	936	
92	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	4,623	3,695	890	2	23	14	
93	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	452,181	361,403	87,013	167	2,246	1,352	
94	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	648,350	518,190	124,761	239	3,221	1,939	
95	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
96	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
97	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	64,498	51,550	12,411	24	320	193	
98	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
99	39202	Trailers	6.2	P, S, T & D Plant - Customer	13,056	10,435	2,512	5	65	39	
100	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
101	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	2,549,018	2,037,287	490,504	940	12,663	7,624	
102	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
103	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
104	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
105	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
106	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	154,845	123,759	29,797	57	769	463	
107	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
108	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
109	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
110	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	1,064,412	850,725	204,823	392	5,288	3,183	
111	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
112	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	7,645	6,110	1,471	3	38	23	
113	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
114	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
115	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
116	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
117	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	189,359	151,344	36,438	70	941	566	
118	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
119	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
120	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
121	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
122											
123		Total General Plant			9,258,175	7,399,542	1,781,538	3,412	45,992	27,690	
124											
125		TOTAL DIRECT PLANT			330,980,984	264,534,621	63,690,231	121,996	1,644,223	989,912	
126											
127		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
128											
129		Kentucky Mid-States General Office:									
130											
131		Intangible Plant:									
132											
133	30100	Organization	6.2	P, S, T & D Plant - Customer	33,043	26,409	6,358	12	164	99	
134	30200	Franchises & Consents	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
135	30300	Misc Intangible Plant	6.2	P, S, T & D Plant - Customer	197,845	158,127	38,071	73	983	592	
136											
137		Total Intangible Plant			230,888	184,536	44,429	85	1,147	691	
138											
139		General:									
140											
141	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
142	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	31,978	25,558	6,153	12	159	96	
143	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
144	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
145	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	2,743	2,192	528	1	14	8	
146	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	6,925	5,534	1,332	3	34	21	
147	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	4,802	3,838	924	2	24	14	
148	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
149	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
150	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	733	586	141	0	4	2	
151	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
152	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
153	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
154	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	19,655	15,709	3,782	7	98	59	
155	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	1,690	1,351	325	1	8	5	
156	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
157	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
158	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
159	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
160	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
161	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
162	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
163	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
164	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
165	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
166	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
167	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	5,040	4,028	970	2	25	15	
168	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
169	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
170	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
171	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	7,760	6,202	1,493	3	39	23	
172	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
173	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
174	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
175											
176		Total General Plant			81,326	64,999	15,649	30	404	243	
177											
178		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
179										
180		Shared Services General Office:								
181										
182		General:								
183										
184	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
185	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
186	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	172,431	137,814	33,181	64	857	516
187	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
188	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
189	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	229,223	183,205	44,109	84	1,139	686
190	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	137,088	109,567	26,380	51	681	410
191	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
192	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
193	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	5,135	4,104	988	2	26	15
194	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
195	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
196	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
197	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	491	392	94	0	2	1
198	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
199	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
200	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
201	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
202	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	12,561	10,039	2,417	5	62	38
203	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
204	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
205	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
206	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	1,968	1,573	379	1	10	6
207	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
208	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	937,862	749,581	180,472	346	4,659	2,805
209	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	754,796	603,266	145,244	278	3,750	2,257
210	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	104,214	83,293	20,054	38	518	312
211	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
212	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
213	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	76,668	61,277	14,753	28	381	229
214	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	1,347	1,076	259	0	7	4
215	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	1,762,881	1,408,973	339,229	650	8,758	5,273
216	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	590,509	471,961	113,631	218	2,933	1,766
217	39931	Other Tang. Property - ALGN	6.2	P, S, T & D Plant - Customer	285,233	227,971	54,887	105	1,417	853
218										
219		Total General Plant			5,072,408	4,054,092	976,077	1,870	25,198	15,171
220										
221		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
222										
223		Shared Services Customer Support:								
224										
225		General:								
226										
227	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	75,374	60,242	14,504	28	374	225
228	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
229	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	395,357	315,987	76,078	146	1,964	1,182
230	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
231	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
232	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	60,995	48,750	11,737	22	303	182
233	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	62,952	50,314	12,114	23	313	188
234	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
235	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
236	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	798	638	154	0	4	2
237	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
238	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
239	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
240	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	7,586	6,063	1,460	3	38	23
241	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
242	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
243	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
244	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
245	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	37,792	30,205	7,272	14	188	113
246	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
247	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
248	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
249	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	10,649	8,511	2,049	4	53	32
250	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	2,938	2,348	565	1	15	9
251	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	108,705	86,882	20,918	40	540	325
252	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	35,104	28,056	6,755	13	174	105
253	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	12,683	10,137	2,441	5	63	38
254	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
255	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
256	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	33,438	26,725	6,434	12	166	100
257	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	35	28	7	0	0	0
258	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	2,069,836	1,654,305	398,296	763	10,282	6,191
259	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
260	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
261										
262		Total General Plant			2,914,242	2,329,191	560,784	1,074	14,477	8,716
263										
264		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
265										
266		TOTAL PLANT IN SERVICE - CUSTOMER			339,279,847	271,167,439	65,287,170	125,055	1,685,450	1,014,733
267										
268		TOTAL CWIP W/O AFUDC - CUSTOMER			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
269		Intangible Plant:								
270										
271	30100	Organization	6.4	P, S, T & D Plant - Demand	5,184	2,799	1,727	-	657	-
272	30200	Franchises & Consents	6.4	P, S, T & D Plant - Demand	74,589	40,274	24,855	-	9,459	-
273	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
274										
275		Total Intangible Plant:			79,773	43,074	26,583	0	10,117	0
276										
277		Production Plant:								
278										
279	32520	Producing Leaseholds	3.0	Peak Day	0	-	-	-	-	-
280	32540	Rights of Ways	3.0	Peak Day	0	-	-	-	-	-
281	33100	Production Gas Wells Equipment	3.0	Peak Day	0	-	-	-	-	-
282	33201	Field Lines	3.0	Peak Day	0	-	-	-	-	-
283	33202	Tributary Lines	3.0	Peak Day	0	-	-	-	-	-
284	33400	Field Meas. & Reg. Sta. Equip	3.0	Peak Day	0	-	-	-	-	-
285	33600	Purification Equipment	3.0	Peak Day	0	-	-	-	-	-
286										
287		Total Production Plant			0	0	0	0	0	0
288										
289		Storage Plant:								
290										
291	35010	Land	3.0	Peak Day	130,563	70,498	43,507	-	16,558	-
292	35020	Rights of Way	3.0	Peak Day	2,341	1,264	780	-	297	-
293	35100	Structures and Improvements	3.0	Peak Day	8,958	4,837	2,985	-	1,136	-
294	35102	Compression Station Equipment	3.0	Peak Day	111,754	60,342	37,240	-	14,172	-
295	35103	Meas. & Reg. Sta. Structues	3.0	Peak Day	11,569	6,247	3,855	-	1,467	-
296	35104	Other Structures	3.0	Peak Day	68,721	37,106	22,900	-	8,715	-
297	35200	Wells \ Rights of Way	3.0	Peak Day	6,267,306	3,384,052	2,088,445	-	794,808	-
298	35201	Well Construction	3.0	Peak Day	849,999	458,960	283,244	-	107,795	-
299	35202	Well Equipment	3.0	Peak Day	333,680	180,171	111,192	-	42,317	-
300	35203	Cushion Gas	3.0	Peak Day	847,416	457,565	282,383	-	107,468	-
301	35210	Leaseholds	3.0	Peak Day	89,265	48,199	29,746	-	11,320	-
302	35211	Storage Rights	3.0	Peak Day	27,307	14,745	9,100	-	3,463	-
303	35301	Field Lines	3.0	Peak Day	87,675	47,341	29,216	-	11,119	-
304	35302	Tributary Lines	3.0	Peak Day	104,659	56,511	34,876	-	13,273	-
305	35400	Compressor Station Equipment	3.0	Peak Day	9,032,953	4,877,372	3,010,038	-	1,145,543	-
306	35500	Meas & Reg. Equipment	3.0	Peak Day	136,542	73,726	45,500	-	17,316	-
307	35600	Purification Equipment	3.0	Peak Day	663,749	358,393	221,180	-	84,175	-
308										
309		Total Storage Plant			18,774,458	10,137,330	6,256,185	0	2,380,942	0
310										
311		Transmission:								
312										
313	36510	Land & Land Rights	3.0	Peak Day	26,970	14,563	8,987	-	3,420	-
314	36520	Rights of Way	3.0	Peak Day	867,772	468,556	289,166	-	110,049	-
315	36602	Structures & Improvements	3.0	Peak Day	397,833	214,811	132,569	-	50,452	-
316	36603	Other Structues	3.0	Peak Day	60,826	32,843	20,269	-	7,714	-
317	36700	Mains Cathodic Protection	3.0	Peak Day	47,233	25,504	15,739	-	5,990	-
318	36701	Mains - Steel	3.0	Peak Day	27,826,921	15,025,237	9,272,724	-	3,528,959	-
319	36703	Mains - Anodes	3.0	Peak Day	11,134	6,012	3,710	-	1,412	-
320	36900	Meas. & Reg. Equipment	3.0	Peak Day	1,999,587	1,079,684	666,320	-	253,584	-
321	36901	Meas. & Reg. Equipment	3.0	Peak Day	2,269,499	1,225,424	756,262	-	287,814	-
322										
323		Total Transmission Plant			33,507,777	18,092,634	11,165,748	0	4,249,395	0
324										
325		Distribution:								
326										
327	37400	Land & Land Rights	3.0	Peak Day	613,356	331,184	204,388	-	77,785	-
328	37401	Land	3.0	Peak Day	428,640	231,446	142,835	-	54,359	-
329	37402	Land Rights	3.0	Peak Day	4,157,536	2,244,875	1,385,410	-	527,251	-
330	37403	Land Other	3.0	Peak Day	2,784	1,503	928	-	353	-
331	37500	Structures & Improvements	3.0	Peak Day	336,168	181,515	112,021	-	42,632	-
332	37501	Structures & Improvements T.B.	3.0	Peak Day	99,818	53,897	33,262	-	12,659	-
333	37502	Land Rights	3.0	Peak Day	46,264	24,981	15,417	-	5,867	-
334	37503	Improvements	3.0	Peak Day	4,005	2,163	1,335	-	508	-
335	37600	Mains Cathodic Protection	3.0	Peak Day	3,418,283	1,845,713	1,139,069	-	433,500	-
336	37601	Mains - Steel	3.0	Peak Day	230,553,919	124,488,346	76,827,147	-	29,238,426	-
337	37602	Mains - Plastic	3.0	Peak Day	221,659,304	119,685,669	73,863,208	-	28,110,428	-
338	37603	Mains - Anodes	3.0	Peak Day	3,599,610	1,943,621	1,199,493	-	456,496	-
339	37604	Mains - Leak Clamps	3.0	Peak Day	6,789,879	3,666,218	2,262,582	-	861,080	-
340	37800	Meas & Reg. Sta. Equip - General	3.0	Peak Day	25,594,946	13,820,075	8,528,967	-	3,245,904	-
341	37900	Meas & Reg. Sta. Equip - City Gate	3.0	Peak Day	9,712,761	5,244,437	3,236,569	-	1,231,755	-
342	37905	Meas & Reg. Sta. Equipment T.b.	3.0	Peak Day	1,718,293	927,798	572,584	-	217,911	-
343	38000	Services	99.0	-	0	-	-	-	-	-
344	38100	Meters	99.0	-	0	-	-	-	-	-
345	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
346	38300	House Regulators	99.0	-	0	-	-	-	-	-
347	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
348	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
349	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
350										
351		Total Distribution Plant			508,735,567	274,693,439	169,525,213	0	64,516,914	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
352										
353		General:								
354										
355	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	754,084	407,170	251,282	-	95,632	-
356	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	5,760,952	3,110,645	1,919,714	-	730,593	-
357	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
358	39002	Structures-Brick	6.4	P, S, T & D Plant - Demand	107,736	58,172	35,901	-	13,663	-
359	39003	Improvements	6.4	P, S, T & D Plant - Demand	545,562	294,578	181,797	-	69,187	-
360	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	8,062	4,353	2,687	-	1,022	-
361	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	788,623	425,819	262,792	-	100,012	-
362	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	1,130,748	610,551	376,798	-	143,399	-
363	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
364	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
365	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	112,487	60,738	37,484	-	14,265	-
366	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
367	39202	Trailers	6.4	P, S, T & D Plant - Demand	22,770	12,295	7,588	-	2,888	-
368	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
369	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	4,445,590	2,400,411	1,481,397	-	563,782	-
370	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
371	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
372	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
373	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
374	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	270,056	145,817	89,990	-	34,248	-
375	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
376	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
377	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
378	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	1,856,377	1,002,357	618,598	-	235,422	-
379	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
380	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	13,334	7,200	4,443	-	1,691	-
381	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
382	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
383	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
384	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
385	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	330,250	178,320	110,049	-	41,882	-
386	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
387	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
388	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
389	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
390										
391		Total General Plant			16,146,631	8,718,426	5,380,518	0	2,047,686	0
392										
393		TOTAL DIRECT PLANT			577,244,205	311,684,903	192,354,247	0	73,205,055	0
394										
395		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
396										
397		Kentucky Mid-States General Office:								
398										
399		Intangible Plant:								
400										
401	30100	Organization	6.4	P, S, T & D Plant - Demand	57,628	31,116	19,203	-	7,308	-
402	30200	Franchises & Consents	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
403	30300	Misc Intangible Plant	6.4	P, S, T & D Plant - Demand	345,050	186,311	114,981	-	43,759	-
404										
405		Total Intangible Plant:			402,678	217,427	134,184	0	51,067	0
406										
407		General:								
408										
409	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
410	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	55,771	30,114	18,584	-	7,073	-
411	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
412	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
413	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	4,784	2,583	1,594	-	607	-
414	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	12,077	6,521	4,024	-	1,532	-
415	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	8,374	4,522	2,790	-	1,062	-
416	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
417	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
418	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	1,278	690	426	-	162	-
419	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
420	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
421	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
422	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	34,279	18,509	11,423	-	4,347	-
423	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	2,948	1,592	982	-	374	-
424	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
425	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
426	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
427	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
428	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
429	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
430	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
431	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
432	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
433	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
434	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
435	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	8,790	4,746	2,929	-	1,115	-
436	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
437	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
438	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
439	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	13,535	7,308	4,510	-	1,716	-
440	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
441	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
442	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
443										
444		Total General Plant			141,835	76,584	47,264	0	17,987	0
445										
446		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF PLANT IN SERVICE											
447											
448		Shared Services General Office:									
449											
450		General:									
451											
452	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
453	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
454	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	300,727	162,378	100,211	-	38,138	-	
455	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
456	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
457	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	399,775	215,860	133,216	-	50,699	-	
458	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	239,087	129,096	79,671	-	30,321	-	
459	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
460	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
461	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	8,955	4,835	2,984	-	1,136	-	
462	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
463	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
464	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
465	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	856	462	285	-	109	-	
466	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
467	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
468	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
469	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
470	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	21,907	11,829	7,300	-	2,778	-	
471	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
472	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
473	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
474	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	3,433	1,854	1,144	-	435	-	
475	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
476	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	1,635,670	883,185	545,052	-	207,433	-	
477	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	1,316,395	710,792	438,660	-	166,943	-	
478	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	181,754	98,139	60,566	-	23,050	-	
479	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
480	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
481	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	133,712	72,198	44,557	-	16,957	-	
482	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	2,349	1,268	783	-	298	-	
483	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	3,074,536	1,660,106	1,024,523	-	389,907	-	
484	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	1,029,871	556,082	343,182	-	130,606	-	
485	39931	Other Tang. Property - ALGN	6.4	P, S, T & D Plant - Demand	497,458	268,604	165,767	-	63,087	-	
486											
487		Total General Plant			8,846,484	4,776,688	2,947,901	0	1,121,895	0	
488											
489		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
490											
491		Shared Services Customer Support:									
492											
493		General:									
494											
495	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	131,455	70,980	43,805	-	16,671	-	
496	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
497	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	689,519	372,308	229,767	-	87,443	-	
498	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
499	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
500	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	106,377	57,439	35,448	-	13,491	-	
501	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	109,791	59,282	36,586	-	13,924	-	
502	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
503	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
504	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	1,392	752	464	-	177	-	
505	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
506	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
507	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
508	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	13,230	7,144	4,409	-	1,678	-	
509	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
510	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
511	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
512	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
513	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	65,911	35,589	21,963	-	8,359	-	
514	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
515	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
516	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
517	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	18,572	10,028	6,189	-	2,355	-	
518	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	5,124	2,767	1,708	-	650	-	
519	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	189,586	102,367	63,175	-	24,043	-	
520	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	61,222	33,057	20,401	-	7,764	-	
521	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	22,119	11,943	7,371	-	2,805	-	
522	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
523	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
524	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	58,317	31,488	19,433	-	7,396	-	
525	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	61	33	20	-	8	-	
526	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	3,609,878	1,949,166	1,202,915	-	457,798	-	
527	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
528	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
529											
530		Total General Plant			5,082,555	2,744,342	1,693,652	0	644,560	0	
531											
532		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
533											
534		TOTAL PLANT IN SERVICE - DEMAND			591,717,758	319,499,946	197,177,248	0	75,040,564	0	
535											
536		TOTAL CWIP W/O AFUDC - DEMAND			0	0	0	0	0	0	

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
537		Intangible Plant:								
538										
539	30100	Organization	6.6	P, S, T & D Plant - Commodity	173	66	43	1	31	32
540	30200	Franchises & Consents	6.6	P, S, T & D Plant - Commodity	2,496	948	626	13	445	464
541	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
542										
543		Total Intangible Plant:			2,670	1,014	669	14	475	496
544										
545		Production Plant:								
546										
547	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
548	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
549	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
550	33201	Field Lines	99.0	-	0	-	-	-	-	-
551	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
552	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
553	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
554										
555		Total Production Plant			0	0	0	0	0	0
556										
557		Storage Plant:								
558										
559	35010	Land	1.5	Winter Volumes	130,563	49,601	32,736	705	23,252	24,269
560	35020	Rights of Way	1.5	Winter Volumes	2,341	889	587	13	417	435
561	35100	Structures and Improvements	1.5	Winter Volumes	8,958	3,403	2,246	48	1,595	1,665
562	35102	Compression Station Equipment	1.5	Winter Volumes	111,754	42,456	28,020	604	19,903	20,772
563	35103	Meas. & Reg. Sta. Structues	1.5	Winter Volumes	11,569	4,395	2,901	62	2,060	2,150
564	35104	Other Structures	1.5	Winter Volumes	68,721	26,107	17,230	371	12,239	12,774
565	35200	Wells \ Rights of Way	1.5	Winter Volumes	6,267,306	2,380,970	1,571,376	33,854	1,116,163	1,164,943
566	35201	Well Construction	1.5	Winter Volumes	849,999	322,918	213,117	4,591	151,379	157,995
567	35202	Well Equipment	1.5	Winter Volumes	333,680	126,766	83,662	1,802	59,426	62,023
568	35203	Cushion Gas	1.5	Winter Volumes	847,416	321,936	212,469	4,577	150,919	157,515
569	35210	Leaseholds	1.5	Winter Volumes	89,265	33,912	22,381	482	15,897	16,592
570	35211	Storage Rights	1.5	Winter Volumes	27,307	10,374	6,847	148	4,863	5,076
571	35301	Field Lines	1.5	Winter Volumes	87,675	33,308	21,982	474	15,614	16,297
572	35302	Tributary Lines	1.5	Winter Volumes	104,659	39,760	26,241	565	18,639	19,454
573	35400	Compressor Station Equipment	1.5	Winter Volumes	9,032,953	3,431,648	2,264,795	48,793	1,608,705	1,679,011
574	35500	Meas & Reg. Equipment	1.5	Winter Volumes	136,542	51,873	34,235	738	24,317	25,380
575	35600	Purification Equipment	1.5	Winter Volumes	663,749	252,160	166,419	3,585	118,209	123,375
576										
577		Total Storage Plant			18,774,458	7,132,478	4,707,243	101,414	3,343,599	3,489,724
578										
579		Transmission:								
580										
581	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
582	36520	Rights of Way	99.0	-	0	-	-	-	-	-
583	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
584	36603	Other Structues	99.0	-	0	-	-	-	-	-
585	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
586	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
587	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
588	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
589	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
590										
591		Total Transmission Plant			0	0	0	0	0	0
592										
593		Distribution:								
594										
595	37400	Land & Land Rights	1.0	Mcf	0	-	-	-	-	-
596	37401	Land	1.0	Mcf	0	-	-	-	-	-
597	37402	Land Rights	1.0	Mcf	0	-	-	-	-	-
598	37403	Land Other	1.0	Mcf	0	-	-	-	-	-
599	37500	Structures & Improvements	1.0	Mcf	0	-	-	-	-	-
600	37501	Structures & Improvements T.B.	1.0	Mcf	0	-	-	-	-	-
601	37502	Land Rights	1.0	Mcf	0	-	-	-	-	-
602	37503	Improvements	1.0	Mcf	0	-	-	-	-	-
603	37600	Mains Cathodic Protection	1.0	Mcf	0	-	-	-	-	-
604	37601	Mains - Steel	1.0	Mcf	0	-	-	-	-	-
605	37602	Mains - Plastic	1.0	Mcf	0	-	-	-	-	-
606	37603	Mains - Anodes	1.0	Mcf	0	-	-	-	-	-
607	37604	Mains - Leak Clamps	1.0	Mcf	0	-	-	-	-	-
608	37800	Meas & Reg. Sta. Equip - General	1.0	Mcf	0	-	-	-	-	-
609	37900	Meas & Reg. Sta. Equip - City Gate	1.0	Mcf	0	-	-	-	-	-
610	37905	Meas & Reg. Sta. Equipment T.b.	1.0	Mcf	0	-	-	-	-	-
611	38000	Services	99.0	-	0	-	-	-	-	-
612	38100	Meters	99.0	-	0	-	-	-	-	-
613	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
614	38300	House Regulators	99.0	-	0	-	-	-	-	-
615	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
616	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
617	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
618										
619		Total Distribution Plant			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
620										
621		General:								
622										
623	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	25,235	9,587	6,327	136	4,494	4,691
624	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	192,790	73,242	48,338	1,041	34,335	35,835
625	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
626	39002	Structures-Brick	6.6	P, S, T & D Plant - Commodity	3,605	1,370	904	19	642	670
627	39003	Improvements	6.6	P, S, T & D Plant - Commodity	18,257	6,936	4,578	99	3,251	3,394
628	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	270	102	68	1	48	50
629	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	26,391	10,026	6,617	143	4,700	4,906
630	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	37,840	14,376	9,488	204	6,739	7,034
631	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
632	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
633	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	3,764	1,430	944	20	670	700
634	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
635	39202	Trailers	6.6	P, S, T & D Plant - Commodity	762	289	191	4	136	142
636	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
637	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	148,772	56,519	37,301	804	26,495	27,653
638	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
639	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
640	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
641	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
642	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	9,037	3,433	2,266	49	1,609	1,680
643	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
644	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
645	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
646	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	62,124	23,601	15,576	336	11,064	11,547
647	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
648	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	446	170	112	2	79	83
649	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
650	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
651	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
652	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
653	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	11,052	4,199	2,771	60	1,968	2,054
654	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
655	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
656	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
657	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
658										
659		Total General Plant			540,347	205,280	135,479	2,919	96,232	100,438
660										
661		TOTAL DIRECT PLANT			19,317,475	7,338,772	4,843,391	104,347	3,440,306	3,590,658
662										
663		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
664										
665		Kentucky Mid-States General Office:								
666										
667		Intangible Plant:								
668										
669	30100	Organization	6.6	P, S, T & D Plant - Commodity	1,929	733	484	10	343	358
670	30200	Franchises & Consents	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
671	30300	Misc Intangible Plant	6.6	P, S, T & D Plant - Commodity	11,547	4,387	2,895	62	2,056	2,146
672										
673		Total Intangible Plant:			13,476	5,119	3,379	73	2,400	2,505
674										
675		General:								
676										
677	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
678	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	1,866	709	468	10	332	347
679	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
680	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
681	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	160	61	40	1	29	30
682	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	404	154	101	2	72	75
683	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	280	106	70	2	50	52
684	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
685	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
686	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	43	16	11	0	8	8
687	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
688	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
689	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
690	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	1,147	436	288	6	204	213
691	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	99	37	25	1	18	18
692	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
693	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
694	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
695	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
696	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
697	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
698	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
699	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
700	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
701	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
702	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
703	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	294	112	74	2	52	55
704	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
705	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
706	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
707	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	453	172	114	2	81	84
708	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
709	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
710	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
711										
712		Total General Plant			4,747	1,803	1,190	26	845	882
713										
714		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
715										
716		Shared Services General Office:								
717										
718		General:								
719										
720	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
721	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
722	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	10,064	3,823	2,523	54	1,792	1,871
723	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
724	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
725	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	13,378	5,083	3,354	72	2,383	2,487
726	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	8,001	3,040	2,006	43	1,425	1,487
727	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
728	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
729	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	300	114	75	2	53	56
730	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
731	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
732	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
733	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	29	11	7	0	5	5
734	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
735	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
736	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
737	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
738	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	733	279	184	4	131	136
739	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
740	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
741	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
742	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	115	44	29	1	20	21
743	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
744	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	54,738	20,795	13,724	296	9,748	10,174
745	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	44,053	16,736	11,045	238	7,846	8,188
746	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	6,082	2,311	1,525	33	1,083	1,131
747	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
748	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
749	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	4,475	1,700	1,122	24	797	832
750	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	79	30	20	0	14	15
751	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	102,889	39,088	25,797	556	18,324	19,125
752	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	34,465	13,093	8,641	186	6,138	6,406
753	39931	Other Tang. Property - ALGN	6.6	P, S, T & D Plant - Commodity	16,647	6,324	4,174	90	2,965	3,094
754										
755		Total General Plant			296,048	112,469	74,227	1,599	52,724	55,028
756										
757		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
758										
759		Shared Services Customer Support:								
760										
761		General:								
762										
763	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	4,399	1,671	1,103	24	783	818
764	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
765	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	23,075	8,766	5,785	125	4,109	4,289
766	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
767	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
768	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	3,560	1,352	893	19	634	662
769	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	3,674	1,396	921	20	654	683
770	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
771	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
772	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	47	18	12	0	8	9
773	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
774	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
775	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
776	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	443	168	111	2	79	82
777	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
778	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
779	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
780	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
781	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	2,206	838	553	12	393	410
782	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
783	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
784	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
785	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	621	236	156	3	111	116
786	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	171	65	43	1	31	32
787	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	6,344	2,410	1,591	34	1,130	1,179
788	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	2,049	778	514	11	365	381
789	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	740	281	186	4	132	138
790	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
791	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
792	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	1,952	741	489	11	348	363
793	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	2	1	1	0	0	0
794	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	120,805	45,894	30,289	653	21,514	22,455
795	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
796	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
797										
798		Total General Plant			170,088	64,617	42,645	919	30,291	31,615
799										
800		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
801										
802		TOTAL PLANT IN SERVICE - COMMODITY			19,801,832	7,522,781	4,964,832	106,964	3,526,567	3,680,688
803										
804		TOTAL CWIP W/O AFUDC - COMMODITY			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Total Plant in Service

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
805		Intangible Plant:								
806										
807	30100	Organization			8,330	5,241	2,343	2	703	41
808	30200	Franchises & Consents			119,853	75,405	33,711	29	10,116	592
809	30300	Misc Intangible Plant			0	-	-	-	-	-
810										
811		Total Intangible Plant:			128,182	80,645	36,054	31	10,819	633
812										
813		Production Plant:								
814										
815	32520	Producing Leaseholds			0	-	-	-	-	-
816	32540	Rights of Ways			0	-	-	-	-	-
817	33100	Production Gas Wells Equipment			0	-	-	-	-	-
818	33201	Field Lines			0	-	-	-	-	-
819	33202	Tributary Lines			0	-	-	-	-	-
820	33400	Field Meas. & Reg. Sta. Equip			0	-	-	-	-	-
821	33600	Purification Equipment			0	-	-	-	-	-
822										
823		Total Production Plant			0	0	0	0	0	0
824										
825		Storage Plant:								
826										
827	35010	Land			261,127	120,100	76,243	705	39,810	24,269
828	35020	Rights of Way			4,682	2,153	1,367	13	714	435
829	35100	Structures and Improvements			17,916	8,240	5,231	48	2,731	1,665
830	35102	Compression Station Equipment			223,508	102,798	65,259	604	34,075	20,772
831	35103	Meas. & Reg. Sta. Structues			23,138	10,642	6,756	62	3,528	2,150
832	35104	Other Structures			137,443	63,214	40,130	371	20,954	12,774
833	35200	Wells \ Rights of Way			12,534,611	5,765,022	3,659,821	33,854	1,910,971	1,164,943
834	35201	Well Construction			1,699,999	781,877	496,361	4,591	259,174	157,995
835	35202	Well Equipment			667,359	306,937	194,854	1,802	101,743	62,023
836	35203	Cushion Gas			1,694,833	779,502	494,853	4,577	258,387	157,515
837	35210	Leaseholds			178,530	82,111	52,127	482	27,218	16,592
838	35211	Storage Rights			54,614	25,119	15,946	148	8,326	5,076
839	35301	Field Lines			175,350	80,649	51,198	474	26,733	16,297
840	35302	Tributary Lines			209,319	96,272	61,116	565	31,912	19,454
841	35400	Compressor Station Equipment			18,065,905	8,309,021	5,274,833	48,793	2,754,248	1,679,011
842	35500	Meas & Reg. Equipment			273,084	125,599	79,734	738	41,633	25,380
843	35600	Purification Equipment			1,327,498	610,554	387,599	3,585	202,384	123,375
844										
845		Total Storage Plant			37,548,916	17,269,809	10,963,428	101,414	5,724,541	3,489,724
846										
847		Transmission:								
848										
849	36510	Land & Land Rights			26,970	14,563	8,987	-	3,420	-
850	36520	Rights of Way			867,772	468,556	289,166	-	110,049	-
851	36602	Structures & Improvements			397,833	214,811	132,569	-	50,452	-
852	36603	Other Structues			60,826	32,843	20,269	-	7,714	-
853	36700	Mains Cathodic Protection			47,233	25,504	15,739	-	5,990	-
854	36701	Mains - Steel			27,826,921	15,025,237	9,272,724	-	3,528,959	-
855	36703	Mains - Anodes			11,134	6,012	3,710	-	1,412	-
856	36900	Meas. & Reg. Equipment			1,999,587	1,079,684	666,320	-	253,584	-
857	36901	Meas. & Reg. Equipment			2,269,499	1,225,424	756,262	-	287,814	-
858										
859		Total Transmission Plant			33,507,777	18,092,634	11,165,748	0	4,249,395	0
860										
861		Distribution:								
862										
863	37400	Land & Land Rights			613,356	331,184	204,388	-	77,785	-
864	37401	Land			428,640	231,446	142,835	-	54,359	-
865	37402	Land Rights			4,157,536	2,244,875	1,385,410	-	527,251	-
866	37403	Land Other			2,784	1,503	928	-	353	-
867	37500	Structures & Improvements			336,168	181,515	112,021	-	42,632	-
868	37501	Structures & Improvements T.B.			99,818	53,897	33,262	-	12,659	-
869	37502	Land Rights			46,264	24,981	15,417	-	5,867	-
870	37503	Improvements			4,005	2,163	1,335	-	508	-
871	37600	Mains Cathodic Protection			3,418,283	1,845,713	1,139,069	-	433,500	-
872	37601	Mains - Steel			230,553,919	124,488,346	76,827,147	-	29,238,426	-
873	37602	Mains - Plastic			221,659,304	119,685,669	73,863,208	-	28,110,428	-
874	37603	Mains - Anodes			3,599,610	1,943,621	1,199,493	-	456,496	-
875	37604	Mains - Leak Clamps			6,789,879	3,666,218	2,262,582	-	861,080	-
876	37800	Meas & Reg. Sta. Equip - General			25,594,946	13,820,075	8,528,967	-	3,245,904	-
877	37900	Meas & Reg. Sta. Equip - City Gate			9,712,761	5,244,437	3,236,569	-	1,231,755	-
878	37905	Meas & Reg. Sta. Equipment T.b.			1,718,293	927,798	572,584	-	217,911	-
879	38000	Services			193,916,542	172,131,494	21,572,990	9,386	126,507	76,164
880	38100	Meters			55,920,540	38,934,861	15,880,938	48,900	659,055	396,787
881	38200	Meter Installaitons			61,761,518	43,001,661	17,539,724	54,007	727,894	438,232
882	38300	House Regulators			3,974,497	2,767,256	1,128,722	3,476	46,842	28,201
883	38400	House Reg. Installations			378,094	263,249	107,375	331	4,456	2,683
884	38500	Ind. Meas. & Reg. Sta. Equipment			5,725,878	-	5,670,142	2,467	33,251	20,019
885	38600	Other Prop. On Cust. Prem			0	-	-	-	-	-
886										
887		Total Distribution Plant			830,412,635	531,791,960	231,425,105	118,567	66,114,918	962,086

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
888										
889		General:								
890										
891	38900	Land & Land Rights			1,211,697	762,333	340,811	296	102,274	5,984
892	39000	Structures & Improvements			9,256,964	5,823,968	2,603,686	2,259	781,338	45,715
893	39001	Structures Frame			0	-	-	-	-	-
894	39002	Structures-Brick			173,115	108,914	48,692	42	14,612	855
895	39003	Improvements			876,634	551,530	246,569	214	73,993	4,329
896	39004	Air Conditioning Equipment			12,955	8,150	3,644	3	1,093	64
897	39009	Improvement to leased Premises			1,267,195	797,249	356,421	309	106,958	6,258
898	39100	Office Furniture & Equipment			1,816,939	1,143,117	511,046	443	153,359	8,973
899	39102	Remittance Processing Equip			0	-	-	-	-	-
900	39103	Office Machines			0	-	-	-	-	-
901	39200	Transportation Equipment			180,749	113,717	50,839	44	15,256	893
902	39201	Trucks			0	-	-	-	-	-
903	39202	Trailers			36,588	23,019	10,291	9	3,088	181
904	39300	Stores Equipment			0	-	-	-	-	-
905	39400	Tools, Shop & Garage Equipment			7,143,379	4,494,217	2,009,202	1,743	602,940	35,277
906	39600	Power Operated Equipment			0	-	-	-	-	-
907	39603	Ditchers			0	-	-	-	-	-
908	39604	Backhoes			0	-	-	-	-	-
909	39605	Welders			0	-	-	-	-	-
910	39700	Communication Equipment			433,938	273,009	122,053	106	36,627	2,143
911	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
912	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
913	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
914	39800	Miscellaneous Equipment			2,982,913	1,876,683	838,997	728	251,774	14,731
915	39900	Other Tangible Property			0	-	-	-	-	-
916	39901	Other Tangible Property - Servers - H/W			21,425	13,480	6,026	5	1,808	106
917	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
918	39903	Other Tangible Property - Network - H/W			0	-	-	-	-	-
919	39904	Other Tang. Property - CPU			0	-	-	-	-	-
920	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
921	39906	Other Tang. Property - PC Hardware			530,662	333,863	149,258	129	44,791	2,621
922	39907	Other Tang. Property - PC Software			0	-	-	-	-	-
923	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
924	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
925	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
926										
927		Total General Plant			25,945,153	16,323,248	7,297,536	6,331	2,189,910	128,127
928										
929		TOTAL DIRECT PLANT			927,542,664	583,558,296	260,887,870	226,343	78,289,584	4,580,570
930										
931		CWIP w/o AFUDC			0	-	-	-	-	-
932										
933		Kentucky Mid-States General Office:								
934										
935		Intangible Plant:								
936										
937	30100	Organization			92,599	58,258	26,045	23	7,816	457
938	30200	Franchises & Consents			0	-	-	-	-	-
939	30300	Misc Intangible Plant			554,443	348,825	155,947	135	46,798	2,738
940										
941		Total Intangible Plant:			647,042	407,083	181,992	158	54,614	3,195
942										
943		General:								
944										
945	37400	Land & Land Rights			0	-	-	-	-	-
946	39001	Structures Frame			89,615	56,381	25,206	22	7,564	443
947	36602	Structures & Improvements			0	-	-	-	-	-
948	38900	Land & Land Rights			0	-	-	-	-	-
949	39004	Air Conditioning Equipment			7,687	4,836	2,162	2	649	38
950	39009	Improvement to leased Premises			19,405	12,209	5,458	5	1,638	96
951	39100	Office Furniture & Equipment			13,456	8,466	3,785	3	1,136	66
952	39102	Remittance Processing Equip			0	-	-	-	-	-
953	39103	Office Machines			0	-	-	-	-	-
954	39200	Transportation Equipment			2,054	1,292	578	1	173	10
955	39201	Trucks			0	-	-	-	-	-
956	39202	Trailers			0	-	-	-	-	-
957	39300	Stores Equipment			0	-	-	-	-	-
958	39400	Tools, Shop & Garage Equipment			55,081	34,654	15,492	13	4,649	272
959	39600	Power Operated Equipment			4,736	2,980	1,332	1	400	23
960	39603	Ditchers			0	-	-	-	-	-
961	39604	Backhoes			0	-	-	-	-	-
962	39605	Welders			0	-	-	-	-	-
963	39700	Communication Equipment			0	-	-	-	-	-
964	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
965	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
966	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
967	39800	Miscellaneous Equipment			0	-	-	-	-	-
968	39900	Other Tangible Property			0	-	-	-	-	-
969	39901	Other Tangible Property - Servers - H/W			0	-	-	-	-	-
970	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
971	39903	Other Tangible Property - Network - H/W			14,125	8,887	3,973	3	1,192	70
972	39904	Other Tang. Property - CPU			0	-	-	-	-	-
973	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
974	39906	Other Tang. Property - PC Hardware			0	-	-	-	-	-
975	39907	Other Tang. Property - PC Software			21,748	13,683	6,117	5	1,836	107
976	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
977	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
978	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
979										
980		Total General Plant			227,907	143,387	64,103	56	19,237	1,125
981										
982		CWIP w/o AFUDC			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
983										
984		Shared Services General Office:								
985										
986		General:								
987										
988	37400	Land & Land Rights			0	-	-	-	-	-
989	39001	Structures Frame			0	-	-	-	-	-
990	36602	Structures & Improvements			483,221	304,016	135,915	118	40,786	2,386
991	37503	Improvements			0	-	-	-	-	-
992	39004	Air Conditioning Equipment			0	-	-	-	-	-
993	39009	Improvement to leased Premises			642,376	404,147	180,680	157	54,220	3,172
994	39100	Office Furniture & Equipment			384,176	241,702	108,056	94	32,427	1,897
995	39102	Remittance Processing Equip			0	-	-	-	-	-
996	39103	Office Machines			0	-	-	-	-	-
997	39200	Transportation Equipment			14,389	9,053	4,047	4	1,215	71
998	39201	Trucks			0	-	-	-	-	-
999	39202	Trailers			0	-	-	-	-	-
1000	39300	Stores Equipment			0	-	-	-	-	-
1001	39400	Tools, Shop & Garage Equipment			1,375	865	387	0	116	7
1002	39600	Power Operated Equipment			0	-	-	-	-	-
1003	39603	Ditchers			0	-	-	-	-	-
1004	39604	Backhoes			0	-	-	-	-	-
1005	39605	Welders			0	-	-	-	-	-
1006	39700	Communication Equipment			35,202	22,147	9,901	9	2,971	174
1007	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
1008	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
1009	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
1010	39800	Miscellaneous Equipment			5,516	3,470	1,551	1	466	27
1011	39900	Other Tangible Property			0	-	-	-	-	-
1012	39901	Other Tangible Property - Servers - H/W			2,628,270	1,653,561	739,248	641	221,840	12,979
1013	39902	Other Tangible Property - Servers - S/W			2,115,244	1,330,794	594,950	516	178,538	10,446
1014	39903	Other Tangible Property - Network - H/W			292,050	183,742	82,144	71	24,651	1,442
1015	39904	Other Tang. Property - CPU			0	-	-	-	-	-
1016	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
1017	39906	Other Tang. Property - PC Hardware			214,855	135,175	60,432	52	18,135	1,061
1018	39907	Other Tang. Property - PC Software			3,774	2,375	1,062	1	319	19
1019	39908	Other Tang. Property - Mainframe S/W			4,940,307	3,108,167	1,389,549	1,206	416,988	24,397
1020	39909	Other Tang. Property - Application Software			1,654,844	1,041,136	465,454	404	139,678	8,172
1021	39931	Other Tang. Property - ALGN			799,338	502,899	224,828	195	67,468	3,947
1022										
1023		Total General Plant			14,214,939	8,943,250	3,998,204	3,469	1,199,817	70,199
1024										
1025		CWIP w/o AFUDC			0	-	-	-	-	-
1026										
1027		Shared Services Customer Support:								
1028										
1029		General:								
1030										
1031	37400	Land & Land Rights			211,229	132,893	59,412	52	17,829	1,043
1032	39001	Structures Frame			0	-	-	-	-	-
1033	36602	Structures & Improvements			1,107,950	697,061	311,631	270	93,517	5,471
1034	37503	Improvements			0	-	-	-	-	-
1035	39004	Air Conditioning Equipment			0	-	-	-	-	-
1036	39009	Improvement to leased Premises			170,931	107,541	48,077	42	14,428	844
1037	39100	Office Furniture & Equipment			176,418	110,992	49,621	43	14,891	871
1038	39102	Remittance Processing Equip			0	-	-	-	-	-
1039	39103	Office Machines			0	-	-	-	-	-
1040	39200	Transportation Equipment			2,237	1,407	629	1	189	11
1041	39201	Trucks			0	-	-	-	-	-
1042	39202	Trailers			0	-	-	-	-	-
1043	39300	Stores Equipment			0	-	-	-	-	-
1044	39400	Tools, Shop & Garage Equipment			21,259	13,375	5,979	5	1,794	105
1045	39600	Power Operated Equipment			0	-	-	-	-	-
1046	39603	Ditchers			0	-	-	-	-	-
1047	39604	Backhoes			0	-	-	-	-	-
1048	39605	Welders			0	-	-	-	-	-
1049	39700	Communication Equipment			105,908	66,632	29,789	26	8,939	523
1050	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
1051	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
1052	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
1053	39800	Miscellaneous Equipment			29,842	18,775	8,393	7	2,519	147
1054	39900	Other Tangible Property			8,234	5,180	2,316	2	695	41
1055	39901	Other Tangible Property - Servers - H/W			304,635	191,660	85,684	74	25,713	1,504
1056	39902	Other Tangible Property - Servers - S/W			98,374	61,892	27,670	24	8,303	486
1057	39903	Other Tangible Property - Network - H/W			35,543	22,361	9,997	9	3,000	176
1058	39904	Other Tang. Property - CPU			0	-	-	-	-	-
1059	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
1060	39906	Other Tang. Property - PC Hardware			93,706	58,955	26,357	23	7,909	463
1061	39907	Other Tang. Property - PC Software			98	62	28	0	8	0
1062	39908	Other Tang. Property - Mainframe S/W			5,800,519	3,649,364	1,631,499	1,415	489,595	28,645
1063	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
1064	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
1065										
1066		Total General Plant			8,166,885	5,138,150	2,297,082	1,993	689,329	40,331
1067										
1068		CWIP w/o AFUDC			0	-	-	-	-	-
1069										
1070		TOTAL PLANT IN SERVICE			950,799,437	598,190,165	267,429,251	232,019	80,252,581	4,695,421
1071										
1072		TOTAL CWIP W/O AFUDC			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Intangible Plant:								
2										
3	30100	Organization	6.2	P, S, T & D Plant - Customer	2,972	2,376	572	1	15	9
4	30200	Franchises & Consents	6.2	P, S, T & D Plant - Customer	42,768	34,182	8,230	16	212	128
5	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
6										
7		Total Intangible Plant:			45,740	36,558	8,802	17	227	137
8										
9		Production Plant:								
10										
11	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
12	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
13	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
14	33201	Field Lines	99.0	-	0	-	-	-	-	-
15	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
17	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
18										
19		Total Production Plant			0	0	0	0	0	0
20										
21		Storage Plant:								
22										
23	35010	Land	99.0	-	0	-	-	-	-	-
24	35020	Rights of Way	99.0	-	0	-	-	-	-	-
25	35100	Structures and Improvements	99.0	-	0	-	-	-	-	-
26	35102	Compression Station Equipment	99.0	-	0	-	-	-	-	-
27	35103	Meas. & Reg. Sta. Structues	99.0	-	0	-	-	-	-	-
28	35104	Other Structures	99.0	-	0	-	-	-	-	-
29	35200	Wells \ Rights of Way	99.0	-	0	-	-	-	-	-
30	35201	Well Construction	99.0	-	0	-	-	-	-	-
31	35202	Well Equipment	99.0	-	0	-	-	-	-	-
32	35203	Cushion Gas	99.0	-	0	-	-	-	-	-
33	35210	Leaseholds	99.0	-	0	-	-	-	-	-
34	35211	Storage Rights	99.0	-	0	-	-	-	-	-
35	35301	Field Lines	99.0	-	0	-	-	-	-	-
36	35302	Tributary Lines	99.0	-	0	-	-	-	-	-
37	35400	Compressor Station Equipment	99.0	-	0	-	-	-	-	-
38	35500	Meas & Reg. Equipment	99.0	-	0	-	-	-	-	-
39	35600	Purification Equipment	99.0	-	0	-	-	-	-	-
40										
41		Total Storage Plant			0	-	-	-	-	-
42										
43		Transmission:								
44										
45	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
46	36520	Rights of Way	99.0	-	0	-	-	-	-	-
47	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
48	36603	Other Structues	99.0	-	0	-	-	-	-	-
49	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
50	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
51	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
52	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
53	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
54										
55		Total Transmission Plant			0	-	-	-	-	-
56										
57		Distribution:								
58										
59	37400	Land & Land Rights	2.0	Bills	0	-	-	-	-	-
60	37401	Land	2.0	Bills	0	-	-	-	-	-
61	37402	Land Rights	2.0	Bills	0	-	-	-	-	-
62	37403	Land Other	2.0	Bills	0	-	-	-	-	-
63	37500	Structures & Improvements	2.0	Bills	0	-	-	-	-	-
64	37501	Structures & Improvements T.B.	2.0	Bills	0	-	-	-	-	-
65	37502	Land Rights	2.0	Bills	0	-	-	-	-	-
66	37503	Improvements	2.0	Bills	0	-	-	-	-	-
67	37600	Mains Cathodic Protection	2.0	Bills	0	-	-	-	-	-
68	37601	Mains - Steel	2.0	Bills	0	-	-	-	-	-
69	37602	Mains - Plastic	2.0	Bills	0	-	-	-	-	-
70	37603	Mains - Anodes	2.0	Bills	0	-	-	-	-	-
71	37604	Mains - Leak Clamps	2.0	Bills	0	-	-	-	-	-
72	37800	Meas & Reg. Sta. Equip - General	2.0	Bills	0	-	-	-	-	-
73	37900	Meas & Reg. Sta. Equip - City Gate	2.0	Bills	0	-	-	-	-	-
74	37905	Meas & Reg. Sta. Equipment T.b.	2.0	Bills	0	-	-	-	-	-
75	38000	Services	2.0	Bills	38,828,841	34,466,716	4,319,663	1,879	25,331	15,251
76	38100	Meters	4.0	Meter Investment	23,998,006	16,708,691	6,815,221	20,985	282,830	170,279
77	38200	Meter Installaitons	4.0	Meter Investment	22,719,274	15,818,369	6,452,072	19,867	267,759	161,206
78	38300	House Regulators	4.0	Meter Investment	469,350	326,786	133,291	410	5,532	3,330
79	38400	House Reg. Installations	4.0	Meter Investment	130,024	90,530	36,926	114	1,532	923
80	38500	Ind. Meas. & Reg. Sta. Equipment	2.2	Non-Residential Bills	3,090,645	-	3,060,560	1,332	17,948	10,805
81	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
82										
83		Total Distribution Plant			89,236,139	67,411,092	20,817,734	44,587	600,932	361,794

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
84											
85		General:									
86											
87	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
88	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	702,419	561,404	135,166	259	3,489	2,101	
89	39002	Structures - Brick	6.2	P, S, T & D Plant - Customer	42,398	33,886	8,159	16	211	127	
90	39003	Improvements	6.2	P, S, T & D Plant - Customer	119,567	95,563	23,008	44	594	358	
91	39003	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	3,181	2,543	612	1	16	10	
92	39004	Improvement to Leased Premises	6.2	P, S, T & D Plant - Customer	452,181	361,403	87,013	167	2,246	1,352	
93	39009	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	525,872	420,300	101,193	194	2,612	1,573	
94	39100	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
95	Composite	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
96	39103	Transportation Equipment	6.2	P, S, T & D Plant - Customer	27,054	21,623	5,206	10	134	81	
97	39200	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
98	39201	Trailers	6.2	P, S, T & D Plant - Customer	3,089	2,469	595	1	15	9	
99	39202	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
100	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	1,193,882	954,203	229,737	440	5,931	3,571	
101	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
102	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
103	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
104	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
105	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	130,835	104,569	25,176	48	650	391	
106	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
107	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
108	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
109	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	552,721	441,759	106,359	204	2,746	1,653	
110	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
111	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	7,706	6,159	1,483	3	38	23	
112	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
113	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
114	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
115	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
116	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	189,125	151,157	36,393	70	940	566	
117	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
118	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
119	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
120		Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
121		Retirement Work in Progress	6.2	P, S, T & D Plant - Customer	(590,771)	(472,171)	(113,681)	(218)	(2,935)	(1,767)	
122		AR 15 general plant amortization	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
123											
124		Total General Plant			3,359,260	2,684,869	646,418	1,238	16,688	10,047	
125											
126		TOTAL DIRECT RESERVE FOR DEPRECIATION			92,641,139	70,132,518	21,472,953	45,842	617,847	371,978	
127											
128		Kentucky Mid-States General Office:									
129											
130		Intangible Plant:									
131											
132	30100	Organization	99.0	-	0	-	-	-	-	-	
133	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
134	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
135											
136		Total Intangible Plant:									
137											
138		General:									
139											
140	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
141	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	21,422	17,121	4,122	8	106	64	
142	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
143	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
144	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	2,735	2,186	526	1	14	8	
145	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	6,925	5,534	1,332	3	34	21	
146	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	1,520	1,215	293	1	8	5	
147	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
148	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
149	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	(353)	(282)	(68)	(0)	(2)	(1)	
150	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
151	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
152	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
153	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	9,604	7,676	1,848	4	48	29	
154	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	534	427	103	0	3	2	
155	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
156	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
157	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
158	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	(3,935)	(3,145)	(757)	(1)	(20)	(12)	
159	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
160	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
161	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
162	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	(22,645)	(18,098)	(4,357)	(8)	(112)	(68)	
163	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
164	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
165	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
166	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	3,483	2,784	670	1	17	10	
167	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
168	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
169	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
170	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	7,760	6,202	1,493	3	39	23	
171	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
172	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
173	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
174		Retirement Work in Progress	6.2	P, S, T & D Plant - Customer	9,364	7,484	1,802	3	47	28	
175											
176		Total General Plant			36,415	29,104	7,007	13	181	109	

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
177											
178		Shared Services General Office:									
179											
180		General:									
181											
182	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
183	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	56,501	45,158	10,872	21	281	169	
184	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
185	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
186	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
187	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	177,153	141,588	34,089	65	880	530	
188	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	68,882	55,054	13,255	25	342	206	
189	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	0	0	0	0	0	
190	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	0	0	0	0	0	
191	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	3,709	2,964	714	1	18	11	
192	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
193	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
194	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
195	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	452	361	87	0	2	1	
196	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
197	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
198	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
199	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
200	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	2,749	2,197	529	1	14	8	
201	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
202	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
203	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
204	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	903	722	174	0	4	3	
205	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	(0)	(0)	(0)	(0)	(0)	(0)	
206	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	212,422	169,777	40,876	78	1,055	635	
207	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	250,959	200,578	48,292	93	1,247	751	
208	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	34,162	27,304	6,574	13	170	102	
209	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
210	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
211	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	30,986	24,765	5,963	11	154	93	
212	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	1,134	906	218	0	6	3	
213	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
214	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	1,760,519	1,407,084	338,774	649	8,746	5,265	
215	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
216	ADJ	WTW Adjustment	6.2	P, S, T & D Plant - Customer	3,273	2,616	630	1	16	10	
217											
218		Total General Plant			2,603,804	2,081,075	501,046	960	12,935	7,788	
219					867,566	693,397	166,945	320	4,310	2,595	
220		Shared Services Customer Support:									
221											
222		General:									
223											
224	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
225	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
226	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	150,143	120,001	28,892	55	746	449	
227	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
228	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
229	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	48,855	39,047	9,401	18	243	146	
230	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	35,342	28,247	6,801	13	176	106	
231	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
232	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
233	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	803	642	155	0	4	2	
234	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
235	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
236	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
237	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	3,786	3,026	728	1	19	11	
238	39500	Laboratory Equipment	6.2	P, S, T & D Plant - Customer	1	1	0	0	0	0	
239	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
240	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
241	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
242	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	35,036	28,002	6,742	13	174	105	
243	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
244	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
245	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
246	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	3,603	2,880	693	1	18	11	
247	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	(2,968)	(2,372)	(571)	(1)	(15)	(9)	
248	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	74,227	59,326	14,283	27	369	222	
249	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	35,328	28,236	6,798	13	175	106	
250	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	6,322	5,053	1,216	2	31	19	
251	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
252	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
253	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	12,216	9,763	2,351	5	61	37	
254	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	(1,383)	(1,106)	(266)	(1)	(7)	(4)	
255	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	1,484,017	1,186,092	285,567	547	7,372	4,438	
256	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	2,124	1,697	409	1	11	6	
257	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
258		Retirement Work in Progress	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
259											
260		Total General Plant			1,887,452	1,508,535	363,200	696	9,376	5,645	
261											
262		TOTAL RESERVE FOR DEPRECIATION - CUSTOMER			97,168,809	73,751,233	22,344,207	47,511	640,339	385,519	

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
263		Intangible Plant:								
264										
265	30100	Organization	6.4	P, S, T & D Plant - Demand	5,184	2,799	1,727	-	657	-
266	30200	Franchises & Consents	6.4	P, S, T & D Plant - Demand	74,589	40,274	24,855	-	9,459	-
267	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
268										
269		Total Intangible Plant:			79,773	43,074	26,583	0	10,117	0
270										
271		Production Plant:								
272										
273	32520	Producing Leaseholds	3.0	Peak Day	0	-	-	-	-	-
274	32540	Rights of Ways	3.0	Peak Day	0	-	-	-	-	-
275	33100	Production Gas Wells Equipment	3.0	Peak Day	0	-	-	-	-	-
276	33201	Field Lines	3.0	Peak Day	0	-	-	-	-	-
277	33202	Tributary Lines	3.0	Peak Day	0	-	-	-	-	-
278	33400	Field Meas. & Reg. Sta. Equip	3.0	Peak Day	0	-	-	-	-	-
279	33600	Purification Equipment	3.0	Peak Day	0	-	-	-	-	-
280										
281		Total Production Plant			0	0	0	0	0	0
282										
283		Storage Plant:								
284										
285	35010	Land	3.0	Peak Day	0	-	-	-	-	-
286	35020	Rights of Way	3.0	Peak Day	2,100	1,134	700	-	266	-
287	35100	Structures and Improvements	3.0	Peak Day	3,931	2,123	1,310	-	499	-
288	35102	Compression Station Equipment	3.0	Peak Day	60,220	32,516	20,067	-	7,637	-
289	35103	Meas. & Reg. Sta. Structues	3.0	Peak Day	10,432	5,633	3,476	-	1,323	-
290	35104	Other Structures	3.0	Peak Day	53,002	28,618	17,662	-	6,722	-
291	35200	Wells \ Rights of Way	3.0	Peak Day	1,231,874	665,155	410,496	-	156,224	-
292	35201	Well Construction	3.0	Peak Day	751,264	405,647	250,343	-	95,274	-
293	35202	Well Equipment	3.0	Peak Day	237,180	128,066	79,035	-	30,079	-
294	35203	Cushion Gas	3.0	Peak Day	351,499	189,793	117,130	-	44,577	-
295	35210	Leaseholds	3.0	Peak Day	83,664	45,175	27,879	-	10,610	-
296	35211	Storage Rights	3.0	Peak Day	22,346	12,066	7,446	-	2,834	-
297	35301	Field Lines	3.0	Peak Day	52,783	28,500	17,589	-	6,694	-
298	35302	Tributary Lines	3.0	Peak Day	76,873	41,508	25,616	-	9,749	-
299	35400	Compressor Station Equipment	3.0	Peak Day	341,086	184,170	113,660	-	43,256	-
300	35500	Meas & Reg. Equipment	3.0	Peak Day	83,530	45,102	27,835	-	10,593	-
301	35600	Purification Equipment	3.0	Peak Day	161,314	87,102	53,754	-	20,458	-
302										
303		Total Storage Plant			3,523,099	1,902,309	1,173,997	-	446,793	-
304										
305		Transmission:								
306										
307	36510	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
308	36520	Rights of Way	3.0	Peak Day	587,414	317,176	195,743	-	74,495	-
309	36602	Structures & Improvements	3.0	Peak Day	29,122	15,724	9,704	-	3,693	-
310	36603	Other Structues	3.0	Peak Day	62,894	33,960	20,958	-	7,976	-
311	36700	Mains Cathodic Protection	3.0	Peak Day	33,163	17,907	11,051	-	4,206	-
312	36701	Mains - Steel	3.0	Peak Day	18,044,112	9,742,978	6,012,813	-	2,288,321	-
313	36703	Mains - Anodes	3.0	Peak Day	11,180	6,037	3,725	-	1,418	-
314	36900	Meas. & Reg. Equipment	3.0	Peak Day	620,559	335,073	206,788	-	78,698	-
315	36901	Meas. & Reg. Equipment	3.0	Peak Day	2,023,747	1,092,729	674,370	-	256,648	-
316										
317		Total Transmission Plant			21,412,190	11,561,582	7,135,153	-	2,715,455	-
318										
319		Distribution:								
320										
321	37400	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
322	37401	Land	3.0	Peak Day	0	-	-	-	-	-
323	37402	Land Rights	3.0	Peak Day	644,160	347,816	214,653	-	81,691	-
324	37403	Land Other	3.0	Peak Day	0	-	-	-	-	-
325	37500	Structures & Improvements	3.0	Peak Day	136,375	73,636	45,444	-	17,295	-
326	37501	Structures & Improvements T.B.	3.0	Peak Day	81,770	44,152	27,248	-	10,370	-
327	37502	Land Rights	3.0	Peak Day	40,711	21,982	13,566	-	5,163	-
328	37503	Improvements	3.0	Peak Day	2,204	1,190	735	-	280	-
329	37600	Mains Cathodic Protection	3.0	Peak Day	1,792,334	967,777	597,257	-	227,301	-
330	37601	Mains - Steel	3.0	Peak Day	30,950,942	16,712,063	10,313,738	-	3,925,142	-
331	37602	Mains - Plastic	3.0	Peak Day	28,052,270	15,146,916	9,347,817	-	3,557,538	-
332	37603	Mains - Anodes	3.0	Peak Day	1,851,162	999,541	616,860	-	234,761	-
333	37604	Mains - Leak Clamps	3.0	Peak Day	5,615,083	3,031,882	1,871,106	-	712,095	-
334	37800	Meas & Reg. Sta. Equip - General	3.0	Peak Day	5,288,177	2,855,368	1,762,171	-	670,637	-
335	37900	Meas & Reg. Sta. Equip - City Gate	3.0	Peak Day	1,456,651	786,523	485,398	-	184,730	-
336	37905	Meas & Reg. Sta. Equipment T.b.	3.0	Peak Day	1,068,358	576,863	356,007	-	135,487	-
337	38000	Services	99.0	-	0	-	-	-	-	-
338	38100	Meters	99.0	-	0	-	-	-	-	-
339	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
340	38300	House Regulators	99.0	-	0	-	-	-	-	-
341	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
342	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
343	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
344										
345		Total Distribution Plant			76,980,198	41,565,710	25,651,999	-	9,762,488	-

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
346											
347		General:									
348											
349	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
350	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	1,225,047	661,468	408,221	-	155,358	-	
351	39002	Structures - Brick	6.4	P, S, T & D Plant - Demand	73,944	39,926	24,640	-	9,377	-	
352	39003	Improvements	6.4	P, S, T & D Plant - Demand	208,530	112,596	69,488	-	26,445	-	
353	39003	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	5,548	2,996	1,849	-	704	-	
354	39004	Improvement to Leased Premises	6.4	P, S, T & D Plant - Demand	788,623	425,819	262,792	-	100,012	-	
355	39009	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	917,142	495,214	305,618	-	116,310	-	
356	39100	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
357	39102	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
358	39103	Transportation Equipment	6.4	P, S, T & D Plant - Demand	47,184	25,477	15,723	-	5,984	-	
359	39200	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
360	39201	Trailers	6.4	P, S, T & D Plant - Demand	5,388	2,909	1,796	-	683	-	
361	39202	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
362	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	2,082,178	1,124,279	693,841	-	264,058	-	
363	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
364	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
365	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
366	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
367	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	228,182	123,208	76,037	-	28,938	-	
368	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
369	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
370	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
371	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	963,968	520,497	321,222	-	122,249	-	
372	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
373	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	13,439	7,257	4,478	-	1,704	-	
374	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
375	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
376	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
377	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
378	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	329,841	178,099	109,912	-	41,830	-	
379	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
380	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
381	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
382		Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
383		Retirement Work in Progress	6.4	P, S, T & D Plant - Demand	(1,030,329)	(556,330)	(343,335)	-	(130,664)	-	
384		AR 15 general plant amortization	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
385											
386		Total General Plant			5,858,685	3,163,416	1,952,281	-	742,988	-	
387											
388		TOTAL DIRECT RESERVE FOR DEPRECIATION			107,853,944	58,236,091	35,940,013	0	13,677,840	0	
389											
390		Kentucky Mid-States General Office:									
391											
392		Intangible Plant:									
393											
394	30100	Organization	99.0	-	0	-	-	-	-	-	
395	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
396	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
397											
398		Total Intangible Plant:									
399											
400		General:									
401											
402	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
403	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	37,360	20,173	12,449	-	4,738	-	
404	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
405	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
406	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	4,771	2,576	1,590	-	605	-	
407	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	12,077	6,521	4,024	-	1,532	-	
408	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	2,652	1,432	884	-	336	-	
409	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
410	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
411	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	(616)	(333)	(205)	-	(78)	-	
412	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
413	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
414	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
415	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	16,750	9,044	5,581	-	2,124	-	
416	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	931	503	310	-	118	-	
417	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
418	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
419	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
420	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	(6,862)	(3,705)	(2,287)	-	(870)	-	
421	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
422	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
423	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
424	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	(39,493)	(21,324)	(13,160)	-	(5,008)	-	
425	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
426	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
427	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
428	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	6,074	3,280	2,024	-	770	-	
429	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
430	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
431	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
432	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	13,535	7,308	4,510	-	1,716	-	
433	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
434	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
435	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
436	ADJ	WTW Adjustment	6.4	P, S, T & D Plant - Demand	16,332	8,818	5,442	-	2,071	-	
437											
438		Total General Plant			63,509	34,292	21,163	-	8,054	-	

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
439											
440		Shared Services General Office:									
441											
442		General:									
443											
444	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
445	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	98,539	53,207	32,836	-	12,497	-	
446	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
447	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
448	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
449	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	308,962	166,825	102,955	-	39,182	-	
450	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	120,133	64,866	40,032	-	15,235	-	
451	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	0	0	-	0	-	
452	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	0	0	-	0	-	
453	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	6,468	3,492	2,155	-	820	-	
454	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
455	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
456	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
457	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	788	426	263	-	100	-	
458	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
459	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
460	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
461	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
462	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	4,795	2,589	1,598	-	608	-	
463	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
464	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
465	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
466	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	1,575	850	525	-	200	-	
467	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	(0)	(0)	(0)	-	(0)	-	
468	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	370,472	200,038	123,452	-	46,983	-	
469	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	437,683	236,329	145,849	-	55,506	-	
470	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	59,580	32,170	19,854	-	7,556	-	
471	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
472	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
473	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	54,041	29,179	18,008	-	6,853	-	
474	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	1,978	1,068	659	-	251	-	
475	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
476	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	3,070,416	1,657,881	1,023,150	-	389,385	-	
477	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
478		Retirement Work in Progress	6.4	P, S, T & D Plant - Demand	5,708	3,082	1,902	-	724	-	
479											
480		Total General Plant			4,541,139	2,452,003	1,513,237	-	575,899	-	
481											
482		Shared Services Customer Support:									
483											
484		General:									
485											
486	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
487	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
488	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	261,856	141,390	87,258	-	33,208	-	
489	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
490	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
491	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	85,206	46,007	28,393	-	10,806	-	
492	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	61,638	33,281	20,539	-	7,817	-	
493	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
494	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
495	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	1,401	756	467	-	178	-	
496	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
497	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
498	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
499	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	6,602	3,565	2,200	-	837	-	
500	39500	Laboratory Equipment	6.4	P, S, T & D Plant - Demand	2	1	1	-	0	-	
501	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
502	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
503	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
504	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	61,104	32,993	20,362	-	7,749	-	
505	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
506	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
507	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
508	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	6,283	3,393	2,094	-	797	-	
509	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	(5,176)	(2,795)	(1,725)	-	(656)	-	
510	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	129,456	69,900	43,138	-	16,417	-	
511	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	61,613	33,268	20,531	-	7,814	-	
512	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	11,025	5,953	3,674	-	1,398	-	
513	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
514	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
515	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	21,305	11,504	7,099	-	2,702	-	
516	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	(2,412)	(1,303)	(804)	-	(306)	-	
517	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	2,588,185	1,397,499	862,457	-	328,229	-	
518	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	3,704	2,000	1,234	-	470	-	
519	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
520		Retirement Work in Progress	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
521											
522		Total General Plant			3,291,792	1,777,414	1,096,919	-	417,459	-	
523											
524		TOTAL RESERVE FOR DEPRECIATION - DEMAND			115,750,384	62,499,800	38,571,332	0	14,679,252	0	

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
525		Intangible Plant:								
526										
527	30100	Organization	6.6	P, S, T & D Plant - Commodity	173	66	43	1	31	32
528	30200	Franchises & Consents	6.6	P, S, T & D Plant - Commodity	2,496	948	626	13	445	464
529	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
530										
531		Total Intangible Plant:			2,670	1,014	669	14	475	496
532										
533		Production Plant:								
534										
535	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
536	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
537	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
538	33201	Field Lines	99.0	-	0	-	-	-	-	-
539	33202	Tributary Lines	1.2	Sales Mcf	0	-	-	-	-	-
540	33400	Field Meas. & Reg. Sta. Equip	1.2	Sales Mcf	0	-	-	-	-	-
541	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
542										
543		Total Production Plant			0	0	0	0	0	0
544										
545		Storage Plant:								
546										
547	35010	Land	1.5	Winter Volumes	0	-	-	-	-	-
548	35020	Rights of Way	1.5	Winter Volumes	2,100	798	527	11	374	390
549	35100	Structures and Improvements	1.5	Winter Volumes	3,931	1,494	986	21	700	731
550	35102	Compression Station Equipment	1.5	Winter Volumes	60,220	22,878	15,099	325	10,725	11,193
551	35103	Meas. & Reg. Sta. Structues	1.5	Winter Volumes	10,432	3,963	2,616	56	1,858	1,939
552	35104	Other Structures	1.5	Winter Volumes	53,002	20,135	13,289	286	9,439	9,852
553	35200	Wells \ Rights of Way	1.5	Winter Volumes	1,231,874	467,993	308,863	6,654	219,388	228,976
554	35201	Well Construction	1.5	Winter Volumes	751,264	285,408	188,361	4,058	133,795	139,642
555	35202	Well Equipment	1.5	Winter Volumes	237,180	90,106	59,467	1,281	42,240	44,086
556	35203	Cushion Gas	1.5	Winter Volumes	351,499	133,536	88,130	1,899	62,600	65,335
557	35210	Leaseholds	1.5	Winter Volumes	83,664	31,784	20,977	452	14,900	15,551
558	35211	Storage Rights	1.5	Winter Volumes	22,346	8,489	5,603	121	3,980	4,154
559	35301	Field Lines	1.5	Winter Volumes	52,783	20,052	13,234	285	9,400	9,811
560	35302	Tributary Lines	1.5	Winter Volumes	76,873	29,204	19,274	415	13,691	14,289
561	35400	Compressor Station Equipment	1.5	Winter Volumes	341,086	129,580	85,519	1,842	60,745	63,400
562	35500	Meas & Reg. Equipment	1.5	Winter Volumes	83,530	31,733	20,943	451	14,876	15,526
563	35600	Purification Equipment	1.5	Winter Volumes	161,314	61,284	40,446	871	28,729	29,984
564										
565		Total Storage Plant			3,523,099	1,338,437	883,332	19,031	627,439	654,860
566										
567		Transmission:								
568										
569	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
570	36520	Rights of Way	99.0	-	0	-	-	-	-	-
571	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
572	36603	Other Structues	99.0	-	0	-	-	-	-	-
573	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
574	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
575	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
576	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
577	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
578										
579		Total Transmission Plant			0	-	-	-	-	-
580										
581		Distribution:								
582										
583	37400	Land & Land Rights	99.0	-	0	-	-	-	-	-
584	37401	Land	99.0	-	0	-	-	-	-	-
585	37402	Land Rights	1.0	Mcf	0	-	-	-	-	-
586	37403	Land Other	99.0	-	0	-	-	-	-	-
587	37500	Structures & Improvements	1.0	Mcf	0	-	-	-	-	-
588	37501	Structures & Improvements T.B.	1.0	Mcf	0	-	-	-	-	-
589	37502	Land Rights	1.0	Mcf	0	-	-	-	-	-
590	37503	Improvements	1.0	Mcf	0	-	-	-	-	-
591	37600	Mains Cathodic Protection	1.0	Mcf	0	-	-	-	-	-
592	37601	Mains - Steel	1.0	Mcf	0	-	-	-	-	-
593	37602	Mains - Plastic	1.0	Mcf	0	-	-	-	-	-
594	37603	Mains - Anodes	1.0	Mcf	0	-	-	-	-	-
595	37604	Mains - Leak Clamps	1.0	Mcf	0	-	-	-	-	-
596	37800	Meas & Reg. Sta. Equip - General	1.0	Mcf	0	-	-	-	-	-
597	37900	Meas & Reg. Sta. Equip - City Gate	1.0	Mcf	0	-	-	-	-	-
598	37905	Meas & Reg. Sta. Equipment T.b.	1.0	Mcf	0	-	-	-	-	-
599	38000	Services	99.0	-	0	-	-	-	-	-
600	38100	Meters	99.0	-	0	-	-	-	-	-
601	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
602	38300	House Regulators	99.0	-	0	-	-	-	-	-
603	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
604	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
605	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
606										
607		Total Distribution Plant			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF RESERVE FOR DEPRECIATION										
608										
609		General:								
610										
611	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
612	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	40,996	15,575	10,279	221	7,301	7,620
613	39002	Structures - Brick	6.6	P, S, T & D Plant - Commodity	2,475	940	620	13	441	460
614	39003	Improvements	6.6	P, S, T & D Plant - Commodity	6,978	2,651	1,750	38	1,243	1,297
615	39003	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	186	71	47	1	33	35
616	39004	Improvement to Leased Premises	6.6	P, S, T & D Plant - Commodity	26,391	10,026	6,617	143	4,700	4,906
617	39009	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	30,692	11,660	7,695	166	5,466	5,705
618	39100	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
619	39102	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
620	39103	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	1,579	600	396	9	281	293
621	39200	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
622	39201	Trailers	6.6	P, S, T & D Plant - Commodity	180	69	45	1	32	34
623	39202	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
624	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	69,680	26,472	17,471	376	12,410	12,952
625	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
626	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
627	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
628	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
629	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	7,636	2,901	1,915	41	1,360	1,419
630	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
631	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
632	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
633	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	32,259	12,255	8,088	174	5,745	5,996
634	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
635	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	450	171	113	2	80	84
636	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
637	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
638	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
639	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
640	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	11,038	4,193	2,768	60	1,966	2,052
641	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
642	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
643	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
644		Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
645	ADJ	WTW Adjustment	6.6	P, S, T & D Plant - Commodity	(34,480)	(13,099)	(8,645)	(186)	(6,141)	(6,409)
646		AR 15 general plant amortization	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
647										
648		Total General Plant			196,061	74,484	49,158	1,059	34,917	36,443
649										
650		TOTAL DIRECT RESERVE FOR DEPRECIATION			3,721,829	1,413,935	933,159	20,104	662,832	691,799
651										
652		Kentucky Mid-States General Office:								
653										
654		Intangible Plant:								
655										
656	30100	Organization	99.0	-	0	-	-	-	-	-
657	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
658	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
659										
660		Total Intangible Plant:								
661										
662		General:								
663										
664	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
665	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	1,250	475	313	7	223	232
666	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
667	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
668	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	160	61	40	1	28	30
669	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	404	154	101	2	72	75
670	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	89	34	22	0	16	16
671	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
672	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
673	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	(21)	(8)	(5)	(0)	(4)	(4)
674	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
675	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
676	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
677	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	561	213	141	3	100	104
678	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	31	12	8	0	6	6
679	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
680	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
681	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
682	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	(230)	(87)	(58)	(1)	(41)	(43)
683	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
684	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
685	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
686	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	(1,322)	(502)	(331)	(7)	(235)	(246)
687	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
688	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
689	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
690	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	203	77	51	1	36	38
691	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
692	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
693	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
694	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	453	172	114	2	81	84
695	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
696	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
697	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
698		Retirement Work in Progress	6.6	P, S, T & D Plant - Commodity	547	208	137	3	97	102
699										
700		Total General Plant			2,125	807	533	11	379	395

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF RESERVE FOR DEPRECIATION										
701										
702		Shared Services General Office:								
703										
704		General:								
705										
706	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
707	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	3,298	1,253	827	18	587	613
708	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
709	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
710	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
711	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	10,339	3,928	2,592	56	1,841	1,922
712	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	4,020	1,527	1,008	22	716	747
713	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
714	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
715	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	216	82	54	1	39	40
716	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
717	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
718	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
719	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	26	10	7	0	5	5
720	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
721	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
722	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
723	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
724	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	160	61	40	1	29	30
725	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
726	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
727	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
728	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	53	20	13	0	9	10
729	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	(0)	(0)	(0)	(0)	(0)	(0)
730	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	12,398	4,710	3,108	67	2,208	2,304
731	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	14,647	5,564	3,672	79	2,609	2,723
732	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	1,994	757	500	11	355	371
733	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
734	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
735	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	1,808	687	453	10	322	336
736	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	66	25	17	0	12	12
737	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
738	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	102,751	39,036	25,762	555	18,299	19,099
739	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
740		Retirement Work in Progress	6.6	P, S, T & D Plant - Commodity	191	73	48	1	34	36
741										
742		Total General Plant			151,969	57,734	38,103	821	27,065	28,247
743					50,635	19,236	12,695	274	9,018	9,412
744		Shared Services Customer Support:								
745										
746		General:								
747										
748	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
749	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
750	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	8,763	3,329	2,197	47	1,561	1,629
751	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
752	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
753	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	2,851	1,083	715	15	508	530
754	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	2,063	784	517	11	367	383
755	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
756	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
757	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	47	18	12	0	8	9
758	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
759	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
760	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
761	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	221	84	55	1	39	41
762	39500	Laboratory Equipment	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
763	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
764	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
765	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
766	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	2,045	777	513	11	364	380
767	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
768	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
769	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
770	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	210	80	53	1	37	39
771	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	(173)	(66)	(43)	(1)	(31)	(32)
772	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	4,332	1,646	1,086	23	772	805
773	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	2,062	783	517	11	367	383
774	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	369	140	93	2	66	69
775	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
776	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
777	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	713	271	179	4	127	133
778	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	(81)	(31)	(20)	(0)	(14)	(15)
779	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	86,614	32,905	21,716	468	15,425	16,099
780	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	124	47	31	1	22	23
781	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
782		Retirement Work in Progress	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
783										
784		Total General Plant			110,160	41,850	27,620	595	19,619	20,476
785										
786		TOTAL RESERVE FOR DEPRECIATION - COMMODITY			3,986,083	1,514,326	999,414	21,532	709,893	740,918

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Total Reserve for Depreciation

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
787		Intangible Plant:								
788										
789	30100	Organization			8,330	5,241	2,343	2	703	41
790	30200	Franchises & Consents			119,853	75,405	33,711	29	10,116	592
791	30300	Misc Intangible Plant			0	-	-	-	-	-
792										
793		Total Intangible Plant:			128,182	80,645	36,054	31	10,819	633
794										
795		Production Plant:								
796										
797	32520	Producing Leaseholds			0	-	-	-	-	-
798	32540	Rights of Ways			0	-	-	-	-	-
799	33100	Production Gas Wells Equipment			0	-	-	-	-	-
800	33201	Field Lines			0	-	-	-	-	-
801	33202	Tributary Lines			0	-	-	-	-	-
802	33400	Field Meas. & Reg. Sta. Equip			0	-	-	-	-	-
803	33600	Purification Equipment			0	-	-	-	-	-
804										
805		Total Production Plant			0	0	0	0	0	0
806										
807		Storage Plant:								
808										
809	35010	Land			0	-	-	-	-	-
810	35020	Rights of Way			4,200	1,932	1,226	11	640	390
811	35100	Structures and Improvements			7,863	3,616	2,296	21	1,199	731
812	35102	Compression Station Equipment			120,440	55,394	35,166	325	18,362	11,193
813	35103	Meas. & Reg. Sta. Structues			20,864	9,596	6,092	56	3,181	1,939
814	35104	Other Structures			106,003	48,754	30,951	286	16,161	9,852
815	35200	Wells \ Rights of Way			2,463,749	1,133,148	719,358	6,654	375,612	228,976
816	35201	Well Construction			1,502,528	691,055	438,704	4,058	229,069	139,642
817	35202	Well Equipment			474,361	218,172	138,502	1,281	72,319	44,086
818	35203	Cushion Gas			702,999	323,329	205,260	1,899	107,176	65,335
819	35210	Leaseholds			167,328	76,959	48,856	452	25,510	15,551
820	35211	Storage Rights			44,691	20,555	13,049	121	6,813	4,154
821	35301	Field Lines			105,566	48,553	30,823	285	16,094	9,811
822	35302	Tributary Lines			153,747	70,713	44,891	415	23,440	14,289
823	35400	Compressor Station Equipment			682,172	313,750	199,179	1,842	104,001	63,400
824	35500	Meas & Reg. Equipment			167,060	76,836	48,778	451	25,469	15,526
825	35600	Purification Equipment			322,628	148,386	94,200	871	49,186	29,984
826										
827		Total Storage Plant			7,046,197	3,240,745	2,057,329	19,031	1,074,232	654,860
828										
829		Transmission:								
830										
831	36510	Land & Land Rights			0	-	-	-	-	-
832	36520	Rights of Way			587,414	317,176	195,743	-	74,495	-
833	36602	Structures & Improvements			29,122	15,724	9,704	-	3,693	-
834	36603	Other Structues			62,894	33,960	20,958	-	7,976	-
835	36700	Mains Cathodic Protection			33,163	17,907	11,051	-	4,206	-
836	36701	Mains - Steel			18,044,112	9,742,978	6,012,813	-	2,288,321	-
837	36703	Mains - Anodes			11,180	6,037	3,725	-	1,418	-
838	36900	Meas. & Reg. Equipment			620,559	335,073	206,788	-	78,698	-
839	36901	Meas. & Reg. Equipment			2,023,747	1,092,729	674,370	-	256,648	-
840										
841		Total Transmission Plant			21,412,190	11,561,582	7,135,153	-	2,715,455	-
842										
843		Distribution:								
844										
845	37400	Land & Land Rights			0	-	-	-	-	-
846	37401	Land			0	-	-	-	-	-
847	37402	Land Rights			644,160	347,816	214,653	-	81,691	-
848	37403	Land Other			0	-	-	-	-	-
849	37500	Structures & Improvements			136,375	73,636	45,444	-	17,295	-
850	37501	Structures & Improvements T.B.			81,770	44,152	27,248	-	10,370	-
851	37502	Land Rights			40,711	21,982	13,566	-	5,163	-
852	37503	Improvements			2,204	1,190	735	-	280	-
853	37600	Mains Cathodic Protection			1,792,334	967,777	597,257	-	227,301	-
854	37601	Mains - Steel			30,950,942	16,712,063	10,313,738	-	3,925,142	-
855	37602	Mains - Plastic			28,052,270	15,146,916	9,347,817	-	3,557,538	-
856	37603	Mains - Anodes			1,851,162	999,541	616,860	-	234,761	-
857	37604	Mains - Leak Clamps			5,615,083	3,031,882	1,871,106	-	712,095	-
858	37800	Meas & Reg. Sta. Equip - General			5,288,177	2,855,368	1,762,171	-	670,637	-
859	37900	Meas & Reg. Sta. Equip - City Gate			1,456,651	786,523	485,398	-	184,730	-
860	37905	Meas & Reg. Sta. Equipment T.b.			1,068,358	576,863	356,007	-	135,487	-
861	38000	Services			38,828,841	34,466,716	4,319,663	1,879	25,331	15,251
862	38100	Meters			23,998,006	16,708,691	6,815,221	20,985	282,830	170,279
863	38200	Meter Installaitons			22,719,274	15,818,369	6,452,072	19,867	267,759	161,206
864	38300	House Regulators			469,350	326,786	133,291	410	5,532	3,330
865	38400	House Reg. Installations			130,024	90,530	36,926	114	1,532	923
866	38500	Ind. Meas. & Reg. Sta. Equipment			3,090,645	-	3,060,560	1,332	17,948	10,805
867	38600	Other Prop. On Cust. Prem			0	-	-	-	-	-
868										
869		Total Distribution Plant			166,216,337	108,976,803	46,469,733	44,587	10,363,420	361,794

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF RESERVE FOR DEPRECIATION										
870										
871		General:								
872										
873	38900	Land & Land Rights			0	-	-	-	-	-
874	39000	Structures & Improvements			1,968,463	1,238,447	553,665	480	166,149	9,721
875	39002	Structures - Brick			118,817	74,753	33,419	29	10,029	587
876	39003	Improvements			335,075	210,811	94,246	82	28,282	1,655
877	39003	Air Conditioning Equipment			8,916	5,609	2,508	2	753	44
878	39004	Improvement to Leased Premises			1,267,195	797,249	356,421	309	106,958	6,258
879	39009	Office Furniture & Equipment			1,473,706	927,174	414,506	360	124,389	7,278
880	39100	Remittance Processing Equip			0	-	-	-	-	-
881	39102	Office Machines			0	-	-	-	-	-
882	39103	Transportation Equipment			75,817	47,700	21,325	19	6,399	374
883	39200	Trucks			0	-	-	-	-	-
884	39201	Trailers			8,658	5,447	2,435	2	731	43
885	39202	Stores Equipment			0	-	-	-	-	-
886	39400	Tools, Shop & Garage Equipment			3,345,740	2,104,954	941,049	816	282,398	16,523
887	39600	Power Operated Equipment			0	-	-	-	-	-
888	39603	Ditchers			0	-	-	-	-	-
889	39604	Backhoes			0	-	-	-	-	-
890	39605	Welders			0	-	-	-	-	-
891	39700	Communication Equipment			366,653	230,678	103,128	89	30,947	1,811
892	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
893	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
894	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
895	39800	Miscellaneous Equipment			1,548,948	974,512	435,669	378	130,740	7,649
896	39900	Other Tangible Property			0	-	-	-	-	-
897	39901	Other Tangible Property - Servers - H/W			21,595	13,586	6,074	5	1,823	107
898	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
899	39903	Other Tangible Property - Network - H/W			0	-	-	-	-	-
900	39904	Other Tang. Property - CPU			0	-	-	-	-	-
901	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
902	39906	Other Tang. Property - PC Hardware			530,003	333,449	149,073	129	44,735	2,617
903	39907	Other Tang. Property - PC Software			0	-	-	-	-	-
904	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
905	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
906		Other Tang. Property - General Startup Costs			0	-	-	-	-	-
907	ADJ	WTW Adjustment			(1,655,581)	(1,041,599)	(465,662)	(404)	(139,740)	(8,176)
908		AR 15 general plant amortization			0	-	-	-	-	-
909										
910		Total General Plant			9,414,005	5,922,769	2,647,856	2,297	794,593	46,490
911										
912		TOTAL DIRECT RESERVE FOR DEPRECIATION			204,216,911	129,782,544	58,346,125	65,947	14,958,518	1,063,777
913										
914		Kentucky Mid-States General Office:								
915										
916		Intangible Plant:								
917										
918	30100	Organization			0	-	-	-	-	-
919	30200	Franchises & Consents			0	-	-	-	-	-
920	30300	Misc Intangible Plant			0	-	-	-	-	-
921										
922		Total Intangible Plant:								
923										
924		General:								
925										
926	37400	Land & Land Rights			0	-	-	-	-	-
927	39001	Structures Frame			60,032	37,769	16,885	15	5,067	296
928	36602	Structures & Improvements			0	-	-	-	-	-
929	38900	Land & Land Rights			0	-	-	-	-	-
930	39004	Air Conditioning Equipment			7,666	4,823	2,156	2	647	38
931	39009	Improvement to leased Premises			19,405	12,209	5,458	5	1,638	96
932	39100	Office Furniture & Equipment			4,261	2,681	1,198	1	360	21
933	39102	Remittance Processing Equip			0	-	-	-	-	-
934	39103	Office Machines			0	-	-	-	-	-
935	39200	Transportation Equipment			(990)	(623)	(279)	(0)	(84)	(5)
936	39201	Trucks			0	-	-	-	-	-
937	39202	Trailers			0	-	-	-	-	-
938	39300	Stores Equipment			0	-	-	-	-	-
939	39400	Tools, Shop & Garage Equipment			26,914	16,933	7,570	7	2,272	133
940	39600	Power Operated Equipment			1,496	941	421	0	126	7
941	39603	Ditchers			0	-	-	-	-	-
942	39604	Backhoes			0	-	-	-	-	-
943	39605	Welders			0	-	-	-	-	-
944	39700	Communication Equipment			(11,027)	(6,937)	(3,101)	(3)	(931)	(54)
945	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
946	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
947	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
948	39800	Miscellaneous Equipment			(63,459)	(39,925)	(17,849)	(15)	(5,356)	(313)
949	39900	Other Tangible Property			0	-	-	-	-	-
950	39901	Other Tangible Property - Servers - H/W			0	-	-	-	-	-
951	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
952	39903	Other Tangible Property - Network - H/W			9,760	6,141	2,745	2	824	48
953	39904	Other Tang. Property - CPU			0	-	-	-	-	-
954	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
955	39906	Other Tang. Property - PC Hardware			0	-	-	-	-	-
956	39907	Other Tang. Property - PC Software			21,748	13,683	6,117	5	1,836	107
957	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
958	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
959	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
960		Retirement Work in Progress			26,243	16,511	7,381	6	2,215	130
961										
962		Total General Plant			102,049	64,204	28,703	25	8,614	504

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF RESERVE FOR DEPRECIATION										
963										
964		Shared Services General Office:								
965										
966		General:								
967										
968	37400	Land & Land Rights			0	-	-	-	-	-
969	39000	Structures & Improvements			158,337	99,617	44,535	39	13,365	782
970	36602	Structures & Improvements			0	-	-	-	-	-
971	37503	Improvements			0	-	-	-	-	-
972	39004	Air Conditioning Equipment			0	-	-	-	-	-
973	39009	Improvement to leased Premises			496,454	312,341	139,637	121	41,903	2,452
974	39100	Office Furniture & Equipment			193,036	121,447	54,295	47	16,293	953
975	39102	Remittance Processing Equip			0	0	0	0	0	0
976	39103	Office Machines			0	0	0	0	0	0
977	39200	Transportation Equipment			10,393	6,539	2,923	3	877	51
978	39201	Trucks			0	-	-	-	-	-
979	39202	Trailers			0	-	-	-	-	-
980	39300	Stores Equipment			0	-	-	-	-	-
981	39400	Tools, Shop & Garage Equipment			1,267	797	356	0	107	6
982	39600	Power Operated Equipment			0	-	-	-	-	-
983	39603	Ditchers			0	-	-	-	-	-
984	39604	Backhoes			0	-	-	-	-	-
985	39605	Welders			0	-	-	-	-	-
986	39700	Communication Equipment			7,704	4,847	2,167	2	650	38
987	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
988	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
989	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
990	39800	Miscellaneous Equipment			2,531	1,592	712	1	214	12
991	39900	Other Tangible Property			(0)	(0)	(0)	(0)	(0)	(0)
992	39901	Other Tangible Property - Servers - H/W			595,292	374,525	167,437	145	50,246	2,940
993	39902	Other Tangible Property - Servers - S/W			703,290	442,471	197,813	172	59,361	3,473
994	39903	Other Tangible Property - Network - H/W			95,736	60,232	26,927	23	8,081	473
995	39904	Other Tang. Property - CPU			0	-	-	-	-	-
996	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
997	39906	Other Tang. Property - PC Hardware			86,835	54,632	24,424	21	7,329	429
998	39907	Other Tang. Property - PC Software			3,178	2,000	894	1	268	16
999	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
1000	39909	Other Tang. Property - Application Software			4,933,686	3,104,001	1,387,687	1,204	416,430	24,364
1001	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
1002		Retirement Work in Progress			9,173	5,771	2,580	2	774	45
1003										
1004		Total General Plant			7,296,912	4,590,811	2,052,386	1,781	615,899	36,035
1005										
1006		Shared Services Customer Support:								
1007										
1008		General:								
1009										
1010	37400	Land & Land Rights			0	-	-	-	-	-
1011	39001	Structures Frame			0	-	-	-	-	-
1012	36602	Structures & Improvements			420,763	264,721	118,347	103	35,515	2,078
1013	37503	Improvements			0	-	-	-	-	-
1014	39004	Air Conditioning Equipment			0	-	-	-	-	-
1015	39009	Improvement to leased Premises			136,913	86,138	38,509	33	11,556	676
1016	39100	Office Furniture & Equipment			99,042	62,312	27,857	24	8,360	489
1017	39102	Remittance Processing Equip			0	-	-	-	-	-
1018	39103	Office Machines			0	-	-	-	-	-
1019	39200	Transportation Equipment			2,251	1,416	633	1	190	11
1020	39201	Trucks			0	-	-	-	-	-
1021	39202	Trailers			0	-	-	-	-	-
1022	39300	Stores Equipment			0	-	-	-	-	-
1023	39400	Tools, Shop & Garage Equipment			10,609	6,674	2,984	3	895	52
1024	39500	Laboratory Equipment			4	2	1	0	0	0
1025	39603	Ditchers			0	-	-	-	-	-
1026	39604	Backhoes			0	-	-	-	-	-
1027	39605	Welders			0	-	-	-	-	-
1028	39700	Communication Equipment			98,184	61,772	27,616	24	8,287	485
1029	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
1030	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
1031	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
1032	39800	Miscellaneous Equipment			10,096	6,352	2,840	2	852	50
1033	39900	Other Tangible Property			(8,317)	(5,232)	(2,339)	(2)	(702)	(41)
1034	39901	Other Tangible Property - Servers - H/W			208,015	130,872	58,508	51	17,558	1,027
1035	39902	Other Tangible Property - Servers - S/W			99,003	62,287	27,846	24	8,356	489
1036	39903	Other Tangible Property - Network - H/W			17,716	11,146	4,983	4	1,495	87
1037	39904	Other Tang. Property - CPU			0	-	-	-	-	-
1038	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
1039	39906	Other Tang. Property - PC Hardware			34,234	21,538	9,629	8	2,889	169
1040	39907	Other Tang. Property - PC Software			(3,876)	(2,439)	(1,090)	(1)	(327)	(19)
1041	39908	Other Tang. Property - Mainframe S/W			4,158,816	2,616,496	1,169,741	1,015	351,026	20,538
1042	39909	Other Tang. Property - Application Software			5,952	3,744	1,674	1	502	29
1043	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
1044		Retirement Work in Progress			0	-	-	-	-	-
1045										
1046		Total General Plant			5,289,404	3,327,799	1,487,739	1,291	446,454	26,121
1047										
1048		TOTAL RESERVE FOR DEPRECIATION			216,905,276	137,765,358	61,914,953	69,043	16,029,484	1,126,437

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF OTHER RATE BASE

Customer

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Rate Base Additions:								
2									
3	Materials and Supplies - KY Direct	7.2	Allocated O&M Expenses - Cust	(1,810)	(1,440)	(355)	(1)	(9)	(5)
4	Materials and Supplies - KY Mid-States GO	7.2	Allocated O&M Expenses - Cust	33,722	26,830	6,624	12	160	96
5	Materials and Supplies - Shared Services GO	7.2	Allocated O&M Expenses - Cust	875	697	172	0	4	2
6	Materials and Supplies - Shared Services CS	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
7	Gas Storage Inventory	99.0	-	0	-	-	-	-	-
8	Prepayments - KY Direct	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
9	Prepayments - KY Mid-States GO	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
10	Prepayments - Shared Services GO	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
11	Prepayments - Shared Services CS	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
12	Cash Working Capital	7.2	Allocated O&M Expenses - Cust	(134,880)	(107,312)	(26,495)	(47)	(641)	(384)
13	Regulatory Assets	7.2	Allocated O&M Expenses - Cust	(228,163)	(181,530)	(44,819)	(80)	(1,085)	(650)
14									
15	Total Rate Base Additions			(330,255)	(262,755)	(64,873)	(116)	(1,570)	(940)
16									
17									
18	Rate Base Deductions:								
19									
20	Customer Advances - KY Direct	2.0	Bills	(736,136)	(653,437)	(81,894)	(36)	(480)	(289)
21	Customer Advances - KY Mid-States GO	2.0	Bills	0	-	-	-	-	-
22	Customer Advances - Shared Services GO	2.0	Bills	0	-	-	-	-	-
23	Customer Advances - Shared Services CS	2.0	Bills	0	-	-	-	-	-
24	ADIT - KY Direct (Div 009)	9.2	Allocated Net Plant - Cust	(31,213,046)	(25,450,971)	(5,536,223)	(9,997)	(134,736)	(81,118)
25	ADIT - Shared Services GO (Div 002)	9.2	Allocated Net Plant - Cust	(2,512,364)	(2,048,570)	(445,615)	(805)	(10,845)	(6,529)
26	ADIT - Shared Services CS (Div 012)	9.2	Allocated Net Plant - Cust	(162,395)	(132,416)	(28,804)	(52)	(701)	(422)
27	ADIT - KY Mid-States GO (Div 091)	9.2	Allocated Net Plant - Cust	(60,942)	(49,692)	(10,809)	(20)	(263)	(158)
28	Change in Net Operating Loss Carryforward	9.2	Allocated Net Plant - Cust	(1,918,473)	(1,564,314)	(340,277)	(614)	(8,281)	(4,986)
29									
30	Total Rate Base Deductions			(36,603,357)	(29,899,401)	(6,443,623)	(11,523)	(155,307)	(93,503)
31									
32									
33	TOTAL OTHER RB - CUSTOMER			(36,933,611)	(30,162,156)	(6,508,496)	(11,639)	(156,877)	(94,443)
34									
35	Interest on Customer Deposits	2.0	Bills	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF OTHER RATE BASE

Demand

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
35	Rate Base Additions:								
36									
37	Materials and Supplies - KY Direct	7.4	Allocated O&M Expenses - Demand	(6,064)	(3,274)	(2,021)	-	(769)	-
38	Materials and Supplies - KY Mid-States GO	7.4	Allocated O&M Expenses - Demand	113,001	61,015	37,655	-	14,331	-
39	Materials and Supplies - Shared Services GO	7.4	Allocated O&M Expenses - Demand	2,934	1,584	978	-	372	-
40	Materials and Supplies - Shared Services CS	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
41	Gas Storage Inventory	99.0	-	0	-	-	-	-	-
42	Prepayments - KY Direct	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
43	Prepayments - KY Mid-States GO	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
44	Prepayments - Shared Services GO	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
45	Prepayments - Shared Services CS	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
46	Cash Working Capital	7.4	Allocated O&M Expenses - Demand	(451,970)	(244,042)	(150,609)	-	(57,318)	-
47	Regulatory Assets	7.4	Allocated O&M Expenses - Demand	(764,553)	(412,823)	(254,771)	-	(96,959)	-
48									
49	Total Rate Base Additions			(1,106,652)	(597,540)	(368,768)	0	(140,344)	0
50									
51									
52	Rate Base Deductions:								
53									
54	Customer Advances - KY Direct	99.0	-	0	-	-	-	-	-
55	Customer Advances - KY Mid-States GO	99.0	-	0	-	-	-	-	-
56	Customer Advances - Shared Services GO	99.0	-	0	-	-	-	-	-
57	Customer Advances - Shared Services CS	99.0	-	0	-	-	-	-	-
58	ADIT - KY Direct (Div 009)	9.4	Allocated Net Plant - Demand	(61,361,892)	(33,132,555)	(20,447,534)	-	(7,781,803)	-
59	ADIT - Shared Services GO (Div 002)	9.4	Allocated Net Plant - Demand	(4,939,070)	(2,666,867)	(1,645,839)	-	(626,364)	-
60	ADIT - Shared Services CS (Div 012)	9.4	Allocated Net Plant - Demand	(319,253)	(172,382)	(106,384)	-	(40,487)	-
61	ADIT - KY Mid-States GO (Div 091)	9.4	Allocated Net Plant - Demand	(119,807)	(64,690)	(39,923)	-	(15,194)	-
62	Change in Net Operating Loss Carryforward	9.4	Allocated Net Plant - Demand	(3,771,537)	(2,036,454)	(1,256,784)	-	(478,299)	-
63									
64	Total Rate Base Deductions			(70,511,559)	(38,072,948)	(23,496,464)	-	(8,942,147)	-
65									
66									
67	TOTAL OTHER RB - DEMAND			(71,618,211)	(38,670,488)	(23,865,232)	-	(9,082,491)	-
68									
69	Interest on Customer Deposits	3.0	Peak Day	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF OTHER RATE BASE

Commodity

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
69	Rate Base Additions:								
70									
71	Materials and Supplies - KY Direct	7.6	Allocated O&M Expenses - Comm	(21,636)	(12,401)	(8,911)	(207)	(56)	(61)
72	Materials and Supplies - KY Mid-States GO	7.6	Allocated O&M Expenses - Comm	403,209	231,093	166,067	3,862	1,051	1,136
73	Materials and Supplies - Shared Services GO	7.6	Allocated O&M Expenses - Comm	10,467	5,999	4,311	100	27	29
74	Materials and Supplies - Shared Services CS	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
75	Gas Storage Inventory	1.0	Mcf	9,182,907	2,698,711	1,939,383	57,760	2,147,889	2,339,165
76	Prepayments - KY Direct	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
77	Prepayments - KY Mid-States GO	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
78	Prepayments - Shared Services GO	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
79	Prepayments - Shared Services CS	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
80	Cash Working Capital	7.6	Allocated O&M Expenses - Comm	(1,612,716)	(924,302)	(664,221)	(15,447)	(4,204)	(4,543)
81	Regulatory Assets	7.6	Allocated O&M Expenses - Comm	(2,728,075)	(1,563,552)	(1,123,597)	(26,131)	(7,111)	(7,684)
82									
83	Total Rate Base Additions			5,234,156	435,548	313,032	19,937	2,137,596	2,328,042
84									
85									
86	Rate Base Deductions:								
87									
88	Customer Advances - KY Direct	99.0	-	0	-	-	-	-	-
89	Customer Advances - KY Mid-States GO	99.0	-	0	-	-	-	-	-
90	Customer Advances - Shared Services GO	99.0	-	0	-	-	-	-	-
91	Customer Advances - Shared Services CS	99.0	-	0	-	-	-	-	-
92	ADIT - KY Direct (Div 009)	9.6	Allocated Net Plant - Comm	(2,038,972)	(774,612)	(511,223)	(11,014)	(363,127)	(378,996)
93	ADIT - Shared Services GO (Div 002)	9.6	Allocated Net Plant - Comm	(164,119)	(62,349)	(41,149)	(887)	(29,228)	(30,506)
94	ADIT - Shared Services CS (Div 012)	9.6	Allocated Net Plant - Comm	(10,608)	(4,030)	(2,660)	(57)	(1,889)	(1,972)
95	ADIT - KY Mid-States GO (Div 091)	9.6	Allocated Net Plant - Comm	(3,981)	(1,512)	(998)	(22)	(709)	(740)
96	Change in Net Operating Loss Carryforward	9.6	Allocated Net Plant - Comm	(125,323)	(47,611)	(31,422)	(677)	(22,319)	(23,295)
97									
98	Total Rate Base Deductions			(2,343,003)	(890,115)	(587,452)	(12,656)	(417,272)	(435,508)
99									
100									
101	TOTAL OTHER RB - COMMODITY			2,891,152	(454,566)	(274,419)	7,281	1,720,323	1,892,534
102									
103	Interest on Customer Deposits	1.0	Mcf	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF OTHER RATE BASE

Total Other Rate Base

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
103	Rate Base Additions:								
104									
105	Materials and Supplies - KY Direct			(29,510)	(17,114)	(11,287)	(208)	(834)	(66)
106	Materials and Supplies - KY Mid-States GO			549,932	318,938	210,347	3,874	15,542	1,232
107	Materials and Supplies - Shared Services GO			14,276	8,280	5,461	101	403	32
108	Materials and Supplies - Shared Services CS			0	-	-	-	-	-
109	Gas Storage Inventory			9,182,907	2,698,711	1,939,383	57,760	2,147,889	2,339,165
110	Prepayments - KY Direct			0	-	-	-	-	-
111	Prepayments - KY Mid-States GO			0	-	-	-	-	-
112	Prepayments - Shared Services GO			0	-	-	-	-	-
113	Prepayments - Shared Services CS			0	-	-	-	-	-
114	Cash Working Capital			(2,199,566)	(1,275,657)	(841,325)	(15,495)	(62,163)	(4,927)
115	Regulatory Assets			(3,720,791)	(2,157,905)	(1,423,187)	(26,211)	(105,156)	(8,334)
116									
117	Total Rate Base Additions			3,797,249	(424,747)	(120,609)	19,822	1,995,681	2,327,102
118									
119									
120	Rate Base Deductions:								
121									
122	Customer Advances - KY Direct			(736,136)	(653,437)	(81,894)	(36)	(480)	(289)
123	Customer Advances - KY Mid-States GO			0	-	-	-	-	-
124	Customer Advances - Shared Services GO			0	-	-	-	-	-
125	Customer Advances - Shared Services CS			0	-	-	-	-	-
126	ADIT - KY Direct (Div 009)			(94,613,910)	(59,358,138)	(26,494,980)	(21,011)	(8,279,666)	(460,115)
127	ADIT - Shared Services GO (Div 002)			(7,615,553)	(4,777,787)	(2,132,603)	(1,691)	(666,437)	(37,035)
128	ADIT - Shared Services CS (Div 012)			(492,256)	(308,828)	(137,848)	(109)	(43,077)	(2,394)
129	ADIT - KY Mid-States GO (Div 091)			(184,730)	(115,894)	(51,730)	(41)	(16,166)	(898)
130	Change in Net Operating Loss Carryforward			(5,815,333)	(3,648,378)	(1,628,483)	(1,291)	(508,900)	(28,280)
131									
132	Total Rate Base Deductions			(109,457,919)	(68,862,463)	(30,527,539)	(24,179)	(9,514,726)	(529,012)
133									
134									
135	TOTAL OTHER RB			(105,660,670)	(69,287,210)	(30,648,147)	(4,358)	(7,519,045)	1,798,090
136									
137	Interest on Customer Deposits			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
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Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Production & Gathering:								
2		Operation								
3	7500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
4	7510	Production Maps & Records	99.0	-	0	-	-	-	-	-
5	7530	Field Lines Expenses	99.0	-	0	-	-	-	-	-
6	7540	Field Compressor Station Expense	99.0	-	0	-	-	-	-	-
7	7550	Field Compressor Sta. Fuel & Pwr.	99.0	-	0	-	-	-	-	-
8	7560	Field Meas. & Regul. Station Exp	99.0	-	0	-	-	-	-	-
9	7570	Purification Expense	99.0	-	0	-	-	-	-	-
10	7590	Other Expenses	99.0	-	0	-	-	-	-	-
11		Maintenance								
12	7610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
13	7620	Structures and Improvements	99.0	-	0	-	-	-	-	-
14	7640	Field Line Maintenance	99.0	-	0	-	-	-	-	-
15	7650	Compressor Station Equip. Maint.	99.0	-	0	-	-	-	-	-
16	7660	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
17	7670	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
18	7680	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
19	7690	Gas Processed By Others	99.0	-	0	-	-	-	-	-
20		Total Production & Gathering			0	0	0	0	0	0
21										
22		Other Gas Supply Expenses:								
23		Operation								
24	8001	Intercompany Gas Well-head Purchases	99.0	-	0	-	-	-	-	-
25	8010	Natural gas field line purchases	99.0	-	0	-	-	-	-	-
26	8040	Natural gas city gate purchases	99.0	-	0	-	-	-	-	-
27	8050	Transmission-Operation supervision and engineering	99.0	-	0	-	-	-	-	-
28	8051	Other Gas Purchases / Gas Cost Adjustments	99.0	-	0	-	-	-	-	-
29	8052	PGA for Commercial	99.0	-	0	-	-	-	-	-
30	8053	PGA for Industrial	99.0	-	0	-	-	-	-	-
31	8054	PGA for Public Authority	99.0	-	0	-	-	-	-	-
32	8058	Unbilled PGA Cost	99.0	-	0	-	-	-	-	-
33	8059	PGA Offset to Unrecovered Gas Cost	99.0	-	0	-	-	-	-	-
34	8060	Exchange gas	99.0	-	0	-	-	-	-	-
35	8081	Gas withdrawn from storage-Debit	99.0	-	0	-	-	-	-	-
36	8082	Gas delivered to storage-Credit	99.0	-	0	-	-	-	-	-
37	8120	Gas used for other utility operations-Credit	99.0	-	0	-	-	-	-	-
38	8580	Transmission and compression of gas by others	99.0	-	0	-	-	-	-	-
39		Maintenance								
40	8350	Maint. Of Purch. Gas Meas. Sta.	99.0	-	0	-	-	-	-	-
41		Total Other Gas Supply Expenses			0	0	0	0	0	0
42										
43		Underground Storage:								
44		Operation								
45	8140	Storage-Operation supervision and engineering	99.0	-	0	-	-	-	-	-
46	8160	Wells expenses	99.0	-	0	-	-	-	-	-
47	8170	Lines expenses	99.0	-	0	-	-	-	-	-
48	8180	Compressor station expenses	99.0	-	0	-	-	-	-	-
49	8190	Compressor station fuel and power	99.0	-	0	-	-	-	-	-
50	8200	Storage-Measuring and regulating station expenses	99.0	-	0	-	-	-	-	-
51	8210	Storage-Purification expenses	99.0	-	0	-	-	-	-	-
52	8240	Storage-Other expenses	99.0	-	0	-	-	-	-	-
53	8250	Storage well royalties	99.0	-	0	-	-	-	-	-
54	8260	Rents	99.0	-	0	-	-	-	-	-
55		Maintenance								
56	8300	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
57	8310	Structures and Improvements	99.0	-	0	-	-	-	-	-
58	8320	Reservoirs & Wells Maintenance	99.0	-	0	-	-	-	-	-
59	8330	Line Maintenance	99.0	-	0	-	-	-	-	-
60	8340	Compressor Station Equip Maint	99.0	-	0	-	-	-	-	-
61	8350	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
62	8360	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
63	8410	Other storage expenses-Operation labor and expenses	99.0	-	0	-	-	-	-	-
64		Total Underground Storage Expense			0	0	0	0	0	0
65										
66		Transmission:								
67		Operation								
68	8500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
69	8510	System Control & Load Dispatching	99.0	-	0	-	-	-	-	-
70	8520	Communication Systems Expense	99.0	-	0	-	-	-	-	-
71	8530	Compressor Station Labor Expense	99.0	-	0	-	-	-	-	-
72	8540	Compressor Station Fuel Gas	99.0	-	0	-	-	-	-	-
73	8550	Compressor Station Fuel & Power	99.0	-	0	-	-	-	-	-
74	8560	Mains Expense	99.0	-	0	-	-	-	-	-
75	8570	Meas. & Regul. Station Expenses	99.0	-	0	-	-	-	-	-
76	8580	LDC Payment	99.0	-	0	-	-	-	-	-
77	8580	LDC Payment - A&G	99.0	-	0	-	-	-	-	-
78	8590	Other Expenses	99.0	-	0	-	-	-	-	-
79	8600	Rents	99.0	-	0	-	-	-	-	-
80		Maintenance								
81	8610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
82	8620	Structures and Improvements	99.0	-	0	-	-	-	-	-
83	8630	Mains	99.0	-	0	-	-	-	-	-
84	8640	Compressor Station Equip Maint	99.0	-	0	-	-	-	-	-
85	8650	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
86	8660	Communication Equipment Maintenance	99.0	-	0	-	-	-	-	-
87	8670	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
88		Total Transmission Expense			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF O&M EXPENSES

89											
90			Distribution:								
91			Operation								
92	8700		Supervision and Engineering	10.2	Composite of Accts. 871-879 & 886-893 - Cust	211,070	146,866	60,036	184	2,486	1,497
93	8710		Distribution Load Dispatching	99.0	-	0	-	-	-	-	-
94	8711		Odorization	99.0	-	0	-	-	-	-	-
94	Accts. 376 & 3		Compressor Station Labor & Expenses	11.2	Composite of Accts. 376 & 380 - Cust	0	-	-	-	-	-
95	8740		Mains & Services	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
96	8750		Measuring and Regulating Station Exp. - Gen	11.2	Composite of Accts. 376 & 380 - Cust	0	-	-	-	-	-
97	8760		Measuring and Regulating Station Exp. - Ind.	2.2	Non-Residential Bills	523	-	518	0	3	2
98	8770		Measuring and Regulating Sta. Exp. - City Gate	11.2	Composite of Accts. 376 & 380 - Cust	0	-	-	-	-	-
99	8780		Meters and House Regulator Expense	13.2	Composite of Accts. 381-383 - Cust	938,471	653,413	266,517	821	11,060	6,659
100	8790		Customer Installations Expense	2.0	Bills	257	228	29	0	0	0
101	8800		Other Expense	10.2	Composite of Accts. 871-879 & 886-893 - Cust	304	212	87	0	4	2
102	8810		Rents	10.2	Composite of Accts. 871-879 & 886-893 - Cust	7,397	5,147	2,104	6	87	52
103			Maintenance								
104	8850		Maintenance Supervision and Engineering	10.2	Composite of Accts. 871-879 & 886-893 - Cust	0	-	-	-	-	-
105	8860		Maintenance of Structures and Improvements	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
106	8870		Maintenance of Mains	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
107	8890		Maintenance of compressor station equipment	99.0	-	0	-	-	-	-	-
108	8900		Maint. of Measuring and Regulating Station Equip. - General	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
109	8910		Maint. of Measuring and Regulating Station Equip. - Industrial	2.2	Non-Residential Bills	135	-	133	0	1	0
110	8920		Maint. of Measuring and Regulating Station Equip. - City Gate	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
111	8930		Maintenance of Services	14.2	Account 380 - Cust	0	-	-	-	-	-
112	8940		Maintenance of Meters and House Regulators	13.2	Composite of Accts. 381-383 - Cust	0	-	-	-	-	-
113	8950		Maintenance of Other Equipment	10.2	Composite of Accts. 871-879 & 886-893 - Cust	0	-	-	-	-	-
114			Total Distribution			1,158,157	805,867	329,424	1,012	13,641	8,213
115											
116			Customer Accounts:								
117	9010		Supervision	2.0	Bills	0	-	-	-	-	-
118	9020		Meter Reading Expense	2.0	Bills	735,288	652,684	81,800	36	480	289
119	9030		Customer Records and Collection Expenses	2.0	Bills	1,067,803	947,844	118,792	52	697	419
120	9040		Uncollectible Accounts	8.0	Customer Deposit Balances	731,532	496,144	235,187	-	200	-
121	9050		Miscellaneous Customer Accounts Expenses	2.0	Bills	0	-	-	-	-	-
122			Total Customer Accounts			2,534,624	2,096,673	435,779	87	1,376	708
123											
124			Customer Service and Information:								
125	9070		Supervision	2.0	Bills	0	-	-	-	-	-
126	9080		Customer Assistance Expenses	2.0	Bills	0	-	-	-	-	-
127	9090		Informational and Instructional Advertising Expenses	2.0	Bills	214,461	190,368	23,859	10	140	84
128	9100		Miscellaneous Customer Service and Informational Expenses	2.0	Bills	0	-	-	-	-	-
129			Total Customer Service and Information			214,461	190,368	23,859	10	140	84
130											
131			Sales:								
132	9110		Supervision	2.0	Bills	158,549	140,737	17,638	8	103	62
133	9120		Demonstrating and Selling Expenses	2.0	Bills	77,078	68,419	8,575	4	50	30
134	9130		Advertising Expenses	2.0	Bills	36,821	32,685	4,096	2	24	14
135	9160		Miscellaneous Sales Expenses	2.0	Bills	(188,721)	(167,520)	(20,995)	(9)	(123)	(74)
136			Total Sales			83,728	74,321	9,315	4	55	33
137											
138			Administrative & General:								
139			Operation								
140	9200		Administrative and General Salaries	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	0	-	-	-	-	-
141	9210		Office Supplies and Expenses	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	12,576	9,978	2,469	6	77	46
142	9220		Administrative Expenses Transferred - Customer Support	2.0	Bills	0	-	-	-	-	-
143	9220		Administrative Expenses Transferred - General	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	3,323,172	2,636,587	652,498	1,509	20,335	12,243
144	9230		Outside Services Employed	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	12,744	10,111	2,502	6	78	47
145	9240		Property Insurance	9.2	Allocated Net Plant - Cust	0	-	-	-	-	-
146	9250		Injuries and Damages	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	4,235	3,360	831	2	26	16
147	9260		Employee Pensions and Benefits	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	158,911	126,079	31,202	72	972	585
148	9270		Franchise Requirements	2.0	Bills	635	564	71	0	0	0
149	9280		Regulatory Commission Expenses	2.0	Bills	165,392	146,811	18,400	8	108	65
150	930.1		General Advertising Expenses	2.0	Bills	0	-	-	-	-	-
151	930.2		Miscellaneous General Expense	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	4,445	3,526	873	2	27	16
152	ADJ		Adjustments	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	(255,697)	(202,868)	(50,205)	(116)	(1,565)	(942)
153			Maintenance								
154	9320		Maintenance of General Plant	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	0	-	-	-	-	-
155			Total A&G			3,426,413	2,734,148	658,640	1,488	20,059	12,077
156											
157			TOTAL O&M EXPENSE - CUSTOMER			7,417,382	5,901,377	1,457,017	2,602	35,271	21,115

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF O&M EXPENSES

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
158		Production & Gathering:								
159		Operation								
160	7500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
161	7510	Production Maps & Records	99.0	-	0	-	-	-	-	-
162	7530	Field Lines Expenses	99.0	-	0	-	-	-	-	-
163	7540	Field Compressor Station Expense	99.0	-	0	-	-	-	-	-
164	7550	Field Compressor Sta. Fuel & Pwr.	99.0	-	0	-	-	-	-	-
165	7560	Field Meas. & Regul. Station Exp	99.0	-	0	-	-	-	-	-
166	7570	Purification Expense	99.0	-	0	-	-	-	-	-
167	7590	Other Expenses	99.0	-	0	-	-	-	-	-
168		Maintenance								
169	7610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
170	7620	Structures and Improvements	99.0	-	0	-	-	-	-	-
171	7640	Field Line Maintenance	99.0	-	0	-	-	-	-	-
172	7650	Compressor Station Equip. Maint.	99.0	-	0	-	-	-	-	-
173	7660	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
174	7670	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
175	7680	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
176	7690	Gas Processed By Others	99.0	-	0	-	-	-	-	-
177		Total Production & Gathering			0	0	0	0	0	0
178										
179		Other Gas Supply Expenses:								
180		Operation								
181	8001	Intercompany Gas Well-head Purchases	99.0	-	0	-	-	-	-	-
182	8010	Natural gas field line purchases	99.0	-	0	-	-	-	-	-
183	8040	Natural gas city gate purchases	99.0	-	0	-	-	-	-	-
184	8050	Transmission-Operation supervision and engineering	99.0	-	0	-	-	-	-	-
185	8051	Other Gas Purchases / Gas Cost Adjustments	99.0	-	0	-	-	-	-	-
186	8052	PGA for Commercial	99.0	-	0	-	-	-	-	-
187	8053	PGA for Industrial	99.0	-	0	-	-	-	-	-
188	8054	PGA for Public Authority	99.0	-	0	-	-	-	-	-
189	8058	Unbilled PGA Cost	99.0	-	0	-	-	-	-	-
190	8059	PGA Offset to Unrecovered Gas Cost	99.0	-	0	-	-	-	-	-
191	8060	Exchange gas	99.0	-	0	-	-	-	-	-
192	8081	Gas withdrawn from storage-Debit	99.0	-	0	-	-	-	-	-
193	8082	Gas delivered to storage-Credit	99.0	-	0	-	-	-	-	-
194	8120	Gas used for other utility operations-Credit	99.0	-	0	-	-	-	-	-
195	8580	Transmission and compression of gas by others	99.0	-	0	-	-	-	-	-
196		Maintenance								
197	8350	Maint. Of Purch. Gas Meas. Sta.	99.0	-	0	-	-	-	-	-
198		Total Other Gas Supply Expenses			0	0	0	0	0	0
199										
200		Underground Storage:								
201		Operation								
202	8140	Storage-Operation supervision and engineering	3.0	Peak Day	0	-	-	-	-	-
203	8160	Wells expenses	3.0	Peak Day	17,582	9,493	5,859	-	2,230	-
204	8170	Lines expenses	3.0	Peak Day	11,391	6,150	3,796	-	1,445	-
205	8180	Compressor station expenses	3.0	Peak Day	22,388	12,089	7,460	-	2,839	-
206	8190	Compressor station fuel and power	3.0	Peak Day	0	-	-	-	-	-
207	8200	Storage-Measuring and regulating station expenses	3.0	Peak Day	4,768	2,575	1,589	-	605	-
208	8210	Storage-Purification expenses	3.0	Peak Day	41,970	22,662	13,986	-	5,323	-
209	8240	Storage-Other expenses	3.0	Peak Day	0	-	-	-	-	-
210	8250	Storage well royalties	3.0	Peak Day	5,241	2,830	1,746	-	665	-
211	8260	Rents	3.0	Peak Day	0	-	-	-	-	-
212		Maintenance								
213	8300	Maint. Sup., & Eng.	3.0	Peak Day	0	-	-	-	-	-
214	8310	Structures and Improvements	3.0	Peak Day	0	-	-	-	-	-
215	8320	Reservoirs & Wells Maintenance	3.0	Peak Day	0	-	-	-	-	-
216	8330	Line Maintenance	3.0	Peak Day	0	-	-	-	-	-
217	8340	Compressor Station Equip Maint	3.0	Peak Day	23,208	12,531	7,734	-	2,943	-
218	8350	Meas. & Regul. Station Equip Maint	3.0	Peak Day	0	-	-	-	-	-
219	8360	Purification Equipment Maintenance	3.0	Peak Day	0	-	-	-	-	-
220	8410	Other storage expenses-Operation labor and expenses	3.0	Peak Day	116,621	62,970	38,862	-	14,790	-
221		Total Underground Storage Expense			243,169	131,300	81,031	0	30,838	0
222										
223		Transmission:								
224		Operation								
225	8500	Op., Sup., & Eng.	3.0	Peak Day	0	-	-	-	-	-
226	8510	System Control & Load Dispatching	3.0	Peak Day	0	-	-	-	-	-
227	8520	Communication Systems Expense	3.0	Peak Day	0	-	-	-	-	-
228	8530	Compressor Station Labor Expense	3.0	Peak Day	0	-	-	-	-	-
229	8540	Compressor Station Fuel Gas	3.0	Peak Day	0	-	-	-	-	-
230	8550	Compressor Station Fuel & Power	3.0	Peak Day	488	264	163	-	62	-
231	8560	Mains Expense	3.0	Peak Day	145,499	78,563	48,484	-	18,452	-
232	8570	Meas. & Regul. Station Expenses	3.0	Peak Day	11,936	6,445	3,977	-	1,514	-
233	8580	LDC Payment	3.0	Peak Day	0	-	-	-	-	-
234	8580	LDC Payment - A&G	3.0	Peak Day	0	-	-	-	-	-
235	8590	Other Expenses	3.0	Peak Day	0	-	-	-	-	-
236	8600	Rents	3.0	Peak Day	0	-	-	-	-	-
237		Maintenance								
238	8610	Maint. Sup., & Eng.	3.0	Peak Day	0	-	-	-	-	-
239	8620	Structures and Improvements	3.0	Peak Day	0	-	-	-	-	-
240	8630	Mains	3.0	Peak Day	22,915	12,373	7,636	-	2,906	-
241	8640	Compressor Station Equip Maint	3.0	Peak Day	0	-	-	-	-	-
242	8650	Meas. & Regul. Station Equip Maint	3.0	Peak Day	0	-	-	-	-	-
243	8660	Communication Equipment Maintenance	3.0	Peak Day	0	-	-	-	-	-
244	8670	Other Equipment Maintenance	3.0	Peak Day	0	-	-	-	-	-
245		Total Transmission Expense			180,838	97,644	60,261	0	22,934	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF O&M EXPENSES										
246										
247		Distribution:								
248		Operation								
249	8700	Supervision and Engineering	10.4	Composite of Accts. 871-879 & 886-893 - Demand	1,868,213	1,008,748	622,542	-	236,923	-
250	8710	Distribution Load Dispatching	99.0	-	0	-	-	-	-	-
251	8711	Odorization	99.0	-	0	-	-	-	-	-
251	8720	Compressor Station Labor & Expenses	11.4	Composite of Accts. 376 & 380 - Demand	0	-	-	-	-	-
252	8740	Mains & Services	12.4	Composite of Accts. 374-379 - Demand	6,802,984	3,673,294	2,266,949	-	862,742	-
253	8750	Measuring and Regulating Station Exp. - Gen	12.4	Composite of Accts. 374-379 - Demand	1,361,535	735,165	453,702	-	172,667	-
254	8760	Measuring and Regulating Station Exp. - Ind.	99.0	-	0	-	-	-	-	-
255	8770	Measuring and Regulating Sta. Exp. - City Gate	12.4	Composite of Accts. 374-379 - Demand	5,487	2,963	1,829	-	696	-
256	8780	Meters and House Regulator Expense	13.4	Composite of Accts. 381-383 - Demand	0	-	-	-	-	-
257	8790	Customer Installations Expense	99.0	-	0	-	-	-	-	-
258	8800	Other Expense	10.4	Composite of Accts. 871-879 & 886-893 - Demand	2,692	1,454	897	-	341	-
259	8810	Rents	10.4	Composite of Accts. 871-879 & 886-893 - Demand	65,473	35,352	21,817	-	8,303	-
260		Maintenance								
261	8850	Maintenance Supervision and Engineering	10.4	Composite of Accts. 871-879 & 886-893 - Demand	0	-	-	-	-	-
262	8860	Maintenance of Structures and Improvements	12.4	Composite of Accts. 374-379 - Demand	0	-	-	-	-	-
263	8870	Maintenance of Mains	12.4	Composite of Accts. 374-379 - Demand	144,480	78,012	48,145	-	18,323	-
264	8890	Maintenance of compressor station equipment	99.0	-	0	-	-	-	-	-
265	8900	Maint. of Measuring and Regulating Station Equip. - General	12.4	Composite of Accts. 374-379 - Demand	0	-	-	-	-	-
266	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	99.0	-	0	-	-	-	-	-
267	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	12.4	Composite of Accts. 374-379 - Demand	178	96	59	-	23	-
268	8930	Maintenance of Services	14.4	Account 380 - Demand	0	-	-	-	-	-
269	8940	Maintenance of Meters and House Regulators	13.4	Composite of Accts. 381-383 - Demand	0	-	-	-	-	-
270	8950	Maintenance of Other Equipment	10.4	Composite of Accts. 871-879 & 886-893 - Demand	0	-	-	-	-	-
271		Total Distribution			10,251,043	5,535,084	3,415,940	0	1,300,018	0
272										
273		Customer Accounts:								
274	9010	Supervision	99.0	-	0	-	-	-	-	-
275	9020	Meter Reading Expense	99.0	-	0	-	-	-	-	-
276	9030	Customer Records and Collection Expenses	99.0	-	0	-	-	-	-	-
277	9040	Uncollectible Accounts	99.0	-	0	-	-	-	-	-
278	9050	Miscellaneous Customer Accounts Expenses	99.0	-	0	-	-	-	-	-
279		Total Customer Accounts			0	-	-	-	-	-
280										
281		Customer Service and Information:								
282	9070	Supervision	99.0	-	0	-	-	-	-	-
283	9080	Customer Assistance Expenses	99.0	-	0	-	-	-	-	-
284	9090	Informational and Instructional Advertising Expenses	99.0	-	0	-	-	-	-	-
285	9100	Miscellaneous Customer Service and Informational Expenses	99.0	-	0	-	-	-	-	-
286		Total Customer Service and Information			0	-	-	-	-	-
287										
288		Sales:								
289	9110	Supervision	99.0	-	0	-	-	-	-	-
290	9120	Demonstrating and Selling Expenses	99.0	-	0	-	-	-	-	-
291	9130	Advertising Expenses	99.0	-	0	-	-	-	-	-
292	9160	Miscellaneous Sales Expenses	99.0	-	0	-	-	-	-	-
293		Total Sales			0	-	-	-	-	-
294										
295		Administrative & General:								
296		Operation								
297	9200	Administrative and General Salaries	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	0	-	-	-	-	-
298	9210	Office Supplies and Expenses	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	54,695	29,533	18,226	-	6,936	-
299	9220	Administrative Expenses Transferred - Customer Support	99.0	-	0	-	-	-	-	-
300	9220	Administrative Expenses Transferred - General	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	14,452,956	7,803,921	4,816,137	-	1,832,897	-
301	9230	Outside Services Employed	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	55,426	29,928	18,470	-	7,029	-
302	9240	Property Insurance	9.4	Allocated Net Plant - Demand	0	-	-	-	-	-
303	9250	Injuries and Damages	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	18,417	9,944	6,137	-	2,336	-
304	9260	Employee Pensions and Benefits	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	691,125	373,175	230,303	-	87,647	-
305	9270	Franchise Requirements	99.0	-	0	-	-	-	-	-
306	9280	Regulatory Commission Expenses	99.0	-	0	-	-	-	-	-
307	930.1	General Advertising Expenses	99.0	-	0	-	-	-	-	-
308	930.2	Miscellaneous General Expense	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	19,331	10,438	6,442	-	2,451	-
309	ADJ	Adjustments	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	(1,112,062)	(600,461)	(370,571)	-	(141,030)	-
310		Maintenance								
311	9320	Maintenance of General Plant	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	0	-	-	-	-	-
312		Total A&G			14,179,888	7,656,477	4,725,143	0	1,798,267	0
313										
314		TOTAL O&M EXPENSE - DEMAND			24,854,938	13,420,505	8,282,375	0	3,152,058	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
315		Production & Gathering:								
316		Operation								
317	7500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
318	7510	Production Maps & Records	99.0	-	0	-	-	-	-	-
319	7530	Field Lines Expenses	99.0	-	0	-	-	-	-	-
320	7540	Field Compressor Station Expense	99.0	-	0	-	-	-	-	-
321	7550	Field Compressor Sta. Fuel & Pwr.	99.0	-	0	-	-	-	-	-
322	7560	Field Meas. & Regul. Station Exp	18.4	Gas Costs	0	-	-	-	-	-
323	7570	Purification Expense	99.0	-	0	-	-	-	-	-
324	7590	Other Expenses	99.0	-	0	-	-	-	-	-
325		Maintenance								
326	7610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
327	7620	Structures and Improvements	99.0	-	0	-	-	-	-	-
328	7640	Field Line Maintenance	99.0	-	0	-	-	-	-	-
329	7650	Compressor Station Equip. Maint.	99.0	-	0	-	-	-	-	-
330	7660	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
331	7670	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
332	7680	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
333	7690	Gas Processed By Others	99.0	-	0	-	-	-	-	-
334		Total Production & Gathering			0	0	0	0	0	0
335										
336		Other Gas Supply Expenses:								
337		Operation								
338	8001	Intercompany Gas Well-head Purchases	18.4	Gas Costs	0	-	-	-	-	-
339	8010	Natural gas field line purchases	18.4	Gas Costs	115,617	66,622	47,883	1,112	-	-
340	8040	Natural gas city gate purchases	18.4	Gas Costs	50,226,537	28,941,994	20,801,358	483,186	-	-
341	8050	Transmission-Operation supervision and engineering	18.4	Gas Costs	(29,531)	(17,016)	(12,230)	(284)	-	-
342	8051	Other Gas Purchases / Gas Cost Adjustments	18.4	Gas Costs	53,391,020	30,765,461	22,111,930	513,629	-	-
343	8052	PGA for Commercial	18.4	Gas Costs	30,150,016	17,373,318	12,486,652	290,047	-	-
344	8053	PGA for Industrial	18.4	Gas Costs	4,872,096	2,807,444	2,017,782	46,870	-	-
345	8054	PGA for Public Authority	18.4	Gas Costs	4,999,866	2,881,068	2,070,698	48,099	-	-
346	8058	Unbilled PGA Cost	18.4	Gas Costs	(5,763,929)	(3,321,344)	(2,387,135)	(55,450)	-	-
347	8059	PGA Offset to Unrecovered Gas Cost	18.4	Gas Costs	(109,657,357)	(63,187,763)	(45,414,676)	(1,054,918)	-	-
348	8060	Exchange gas	18.4	Gas Costs	(122,035)	(70,320)	(50,541)	(1,174)	-	-
349	8081	Gas withdrawn from storage-Debit	18.4	Gas Costs	30,798,939	17,747,246	12,755,403	296,290	-	-
350	8082	Gas delivered to storage-Credit	18.4	Gas Costs	(14,414,625)	(8,306,127)	(5,969,828)	(138,671)	-	-
351	8120	Gas used for other utility operations-Credit	18.4	Gas Costs	(8,172)	(4,709)	(3,384)	(79)	-	-
352	8580	Transmission and compression of gas by others	18.4	Gas Costs	43,082,454	24,825,365	17,842,630	414,459	-	-
353		Maintenance								
354	8350	Maint. Of Purch. Gas Meas. Sta.	18.4	Gas Costs	0	-	-	-	-	-
355		Total Other Gas Supply Expenses			87,640,898	50,501,238	36,296,543	843,117	0	0
356										
357		Underground Storage:								
358		Operation								
359	8140	Storage-Operation supervision and engineering	1.5	Winter Volumes	0	-	-	-	-	-
360	8160	Wells expenses	1.5	Winter Volumes	17,582	6,679	4,408	95	3,131	3,268
361	8170	Lines expenses	1.5	Winter Volumes	11,391	4,327	2,856	62	2,029	2,117
362	8180	Compressor station expenses	1.5	Winter Volumes	22,388	8,505	5,613	121	3,987	4,161
363	8190	Compressor station fuel and power	1.5	Winter Volumes	0	-	-	-	-	-
364	8200	Storage-Measuring and regulating station expenses	1.5	Winter Volumes	4,768	1,811	1,195	26	849	886
365	8210	Storage-Purification expenses	1.5	Winter Volumes	41,970	15,945	10,523	227	7,475	7,801
366	8240	Storage-Other expenses	1.5	Winter Volumes	0	-	-	-	-	-
367	8250	Storage well royalties	1.5	Winter Volumes	5,241	1,991	1,314	28	933	974
368	8260	Rents	1.5	Winter Volumes	0	-	-	-	-	-
369		Maintenance								
370	8300	Maint. Sup., & Eng.	1.5	Winter Volumes	0	-	-	-	-	-
371	8310	Structures and Improvements	1.5	Winter Volumes	0	-	-	-	-	-
372	8320	Reservoirs & Wells Maintenance	1.5	Winter Volumes	0	-	-	-	-	-
373	8330	Line Maintenance	1.5	Winter Volumes	0	-	-	-	-	-
374	8340	Compressor Station Equip Maint	1.5	Winter Volumes	23,208	8,817	5,819	125	4,133	4,314
375	8350	Meas. & Regul. Station Equip Maint	1.5	Winter Volumes	0	-	-	-	-	-
376	8360	Purification Equipment Maintenance	1.5	Winter Volumes	0	-	-	-	-	-
377	8410	Other storage expenses-Operation labor and expenses	1.5	Winter Volumes	116,621	44,305	29,240	630	20,769	21,677
378		Total Underground Storage Expense			243,169	92,381	60,969	1,314	43,307	45,199
379										
380		Transmission:								
381		Operation								
382	8500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
383	8510	System Control & Load Dispatching	99.0	-	0	-	-	-	-	-
384	8520	Communication Systems Expense	99.0	-	0	-	-	-	-	-
385	8530	Compressor Station Labor Expense	99.0	-	0	-	-	-	-	-
386	8540	Compressor Station Fuel Gas	99.0	-	0	-	-	-	-	-
387	8550	Compressor Station Fuel & Power	99.0	-	0	-	-	-	-	-
388	8560	Mains Expense	99.0	-	0	-	-	-	-	-
389	8570	Meas. & Regul. Station Expenses	99.0	-	0	-	-	-	-	-
390	8580	LDC Payment	99.0	-	0	-	-	-	-	-
391	8580	LDC Payment - A&G	99.0	-	0	-	-	-	-	-
392	8590	Other Expenses	99.0	-	0	-	-	-	-	-
393	8600	Rents	99.0	-	0	-	-	-	-	-
394		Maintenance								
395	8610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
396	8620	Structures and Improvements	99.0	-	0	-	-	-	-	-
397	8630	Mains	99.0	-	0	-	-	-	-	-
398	8640	Compressor Station Equip Maint	99.0	-	0	-	-	-	-	-
399	8650	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
400	8660	Communication Equipment Maintenance	99.0	-	0	-	-	-	-	-
401	8670	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
402		Total Transmission Expense			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF O&M EXPENSES										
403										
404		Distribution:								
405		Operation								
406	8700	Supervision and Engineering	10.6	Composite of Accts. 871-879 & 886-893 - Comm	61,423	18,051	12,972	386	14,367	15,646
407	8710	Distribution Load Dispatching	1.0	Mcf	(41)	(12)	(9)	(0)	(10)	(11)
408	8711	Odorization	1.0	Mcf	132,819	39,034	28,051	835	31,067	33,833
408	8720	Compressor Station Labor & Expenses	99.0	-	0	-	-	-	-	-
409	8740	Mains & Services	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
410	8750	Measuring and Regulating Station Exp. - Gen	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
411	8760	Measuring and Regulating Station Exp. - Ind.	99.0	-	0	-	-	-	-	-
412	8770	Measuring and Regulating Sta. Exp. - City Gate	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
413	8780	Meters and House Regulator Expense	99.0	-	0	-	-	-	-	-
414	8790	Customer Installations Expense	99.0	-	0	-	-	-	-	-
415	8800	Other Expense	10.6	Composite of Accts. 871-879 & 886-893 - Comm	89	26	19	1	21	23
416	8810	Rents	10.6	Composite of Accts. 871-879 & 886-893 - Comm	2,153	633	455	14	503	548
417		Maintenance								
418	8850	Maintenance Supervision and Engineering	10.6	Composite of Accts. 871-879 & 886-893 - Comm	0	-	-	-	-	-
419	8860	Maintenance of Structures and Improvements	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
420	8870	Maintenance of Mains	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
421	8890	Maintenance of compressor station equipment	1.0	Mcf	140,590	41,317	29,692	884	32,884	35,812
422	8900	Maint. of Measuring and Regulating Station Equip. - General	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
423	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	5.0	Direct to Transport Interruptible	0	-	-	-	-	-
424	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
425	8930	Maintenance of Services	14.6	Account 380 - Comm	0	-	-	-	-	-
426	8940	Maintenance of Meters and House Regulators	13.6	Composite of Accts. 381-383 - Comm	0	-	-	-	-	-
427	8950	Maintenance of Other Equipment	10.6	Composite of Accts. 871-879 & 886-893 - Comm	0	-	-	-	-	-
428		Total Distribution			337,032	99,048	71,179	2,120	78,832	85,852
429										
430		Customer Accounts:								
431	9010	Supervision	99.0	-	0	-	-	-	-	-
432	9020	Meter Reading Expense	99.0	-	0	-	-	-	-	-
433	9030	Customer Records and Collection Expenses	99.0	-	0	-	-	-	-	-
434	9040	Uncollectible Accounts	99.0	-	0	-	-	-	-	-
435	9050	Miscellaneous Customer Accounts Expenses	99.0	-	0	-	-	-	-	-
436		Total Customer Accounts			0	-	-	-	-	-
437										
438		Customer Service and Information:								
439	9070	Supervision	99.0	-	0	-	-	-	-	-
440	9080	Customer Assistance Expenses	99.0	-	0	-	-	-	-	-
441	9090	Informational and Instructional Advertising Expenses	99.0	-	0	-	-	-	-	-
442	9100	Miscellaneous Customer Service and Informational Expenses	99.0	-	0	-	-	-	-	-
443		Total Customer Service and Information			0	-	-	-	-	-
444										
445		Sales:								
446	9110	Supervision	99.0	-	0	-	-	-	-	-
447	9120	Demonstrating and Selling Expenses	99.0	-	0	-	-	-	-	-
448	9130	Advertising Expenses	99.0	-	0	-	-	-	-	-
449	9160	Miscellaneous Sales Expenses	99.0	-	0	-	-	-	-	-
450		Total Sales			0	-	-	-	-	-
451										
452		Administrative & General:								
453		Operation								
454	9200	Administrative and General Salaries	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	0	-	-	-	-	-
455	9210	Office Supplies and Expenses	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	1,798	528	380	11	421	458
456	9220	Administrative Expenses Transferred - Customer Support	99.0	-	0	-	-	-	-	-
457	9220	Administrative Expenses Transferred - General	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	475,181	139,648	100,356	2,989	111,145	121,043
458	9230	Outside Services Employed	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	1,822	536	385	11	426	464
459	9240	Property Insurance	9.6	Allocated Net Plant - Comm	0	-	-	-	-	-
460	9250	Injuries and Damages	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	606	178	128	4	142	154
461	9260	Employee Pensions and Benefits	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	22,723	6,678	4,799	143	5,315	5,788
462	9270	Franchise Requirements	99.0	-	0	-	-	-	-	-
463	9280	Regulatory Commission Expenses	99.0	-	0	-	-	-	-	-
464	930.1	General Advertising Expenses	99.0	-	0	-	-	-	-	-
465	930.2	Miscellaneous General Expense	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	636	187	134	4	149	162
466	ADJ	Adjustments	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	(36,562)	(10,745)	(7,722)	(230)	(8,552)	(9,313)
467		Maintenance								
468	9320	Maintenance of General Plant	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	0	-	-	-	-	-
469		Total A&G			466,203	137,010	98,460	2,932	109,045	118,756
470										
471		TOTAL O&M EXPENSE - COMMODITY			88,687,302	50,829,677	36,527,151	849,483	231,184	249,808

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
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ALLOCATION OF O&M EXPENSES

Total O&M Expenses

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
472		Production & Gathering:								
473		Operation								
474	7500	Op., Sup., & Eng.			0	0	0	0	0	0
475	7510	Production Maps & Records			0	0	0	0	0	0
476	7530	Field Lines Expenses			0	0	0	0	0	0
477	7540	Field Compressor Station Expense			0	0	0	0	0	0
478	7550	Field Compressor Sta. Fuel & Pwr.			0	0	0	0	0	0
479	7560	Field Meas. & Regul. Station Exp			0	0	0	0	0	0
480	7570	Purification Expense			0	0	0	0	0	0
481	7590	Other Expenses			0	0	0	0	0	0
482		Maintenance								
483	7610	Maint. Sup., & Eng.			0	0	0	0	0	0
484	7620	Structures and Improvements			0	0	0	0	0	0
485	7640	Field Line Maintenance			0	0	0	0	0	0
486	7650	Compressor Station Equip. Maint.			0	0	0	0	0	0
487	7660	Meas. & Regul. Station Equip Maint			0	0	0	0	0	0
488	7670	Purification Equipment Maintenance			0	0	0	0	0	0
489	7680	Other Equipment Maintenance			0	0	0	0	0	0
490	7690	Gas Processed By Others			0	0	0	0	0	0
491		Total Production & Gathering			0	0	0	0	0	0
492										
493		Other Gas Supply Expenses:								
494		Operation								
495	8001	Intercompany Gas Well-head Purchases			0	0	0	0	0	0
496	8010	Natural gas field line purchases			115,617	66,622	47,883	1,112	0	0
497	8040	Natural gas city gate purchases			50,226,537	28,941,994	20,801,358	483,186	0	0
498	8050	Transmission-Operation supervision and engineering			(29,531)	(17,016)	(12,230)	(284)	0	0
499	8051	Other Gas Purchases / Gas Cost Adjustments			53,391,020	30,765,461	22,111,930	513,629	0	0
500	8052	PGA for Commercial			30,150,016	17,373,318	12,486,652	290,047	0	0
501	8053	PGA for Industrial			4,872,096	2,807,444	2,017,782	46,870	0	0
502	8054	PGA for Public Authority			4,999,866	2,881,068	2,070,698	48,099	0	0
503	8058	Unbilled PGA Cost			(5,763,929)	(3,321,344)	(2,387,135)	(55,450)	0	0
504	8059	PGA Offset to Unrecovered Gas Cost			(109,657,357)	(63,187,763)	(45,414,676)	(1,054,918)	0	0
505	8060	Exchange gas			(122,035)	(70,320)	(50,541)	(1,174)	0	0
506	8081	Gas withdrawn from storage-Debit			30,798,939	17,747,246	12,755,403	296,290	0	0
507	8082	Gas delivered to storage-Credit			(14,414,625)	(8,306,127)	(5,969,828)	(138,671)	0	0
508	8120	Gas used for other utility operations-Credit			(8,172)	(4,709)	(3,384)	(79)	0	0
509	8580	Transmission and compression of gas by others			43,082,454	24,825,365	17,842,630	414,459	0	0
510		Maintenance								
511	8350	Maint. Of Purch. Gas Meas. Sta.			0	0	0	0	0	0
512		Total Other Gas Supply Expenses			87,640,898	50,501,238	36,296,543	843,117	0	0
513										
514		Underground Storage:								
515		Operation								
516	8140	Storage-Operation supervision and engineering			0	0	0	0	0	0
517	8160	Wells expenses			35,164	16,173	10,267	95	5,361	3,268
518	8170	Lines expenses			22,782	10,478	6,652	62	3,473	2,117
519	8180	Compressor station expenses			44,776	20,594	13,074	121	6,826	4,161
520	8190	Compressor station fuel and power			0	0	0	0	0	0
521	8200	Storage-Measuring and regulating station expenses			9,536	4,386	2,784	26	1,454	886
522	8210	Storage-Purification expenses			83,940	38,606	24,509	227	12,797	7,801
523	8240	Storage-Other expenses			0	0	0	0	0	0
524	8250	Storage well royalties			10,482	4,821	3,060	28	1,598	974
525	8260	Rents			0	0	0	0	0	0
526		Maintenance								
527	8300	Maint. Sup., & Eng.			0	0	0	0	0	0
528	8310	Structures and Improvements			0	0	0	0	0	0
529	8320	Reservoirs & Wells Maintenance			0	0	0	0	0	0
530	8330	Line Maintenance			0	0	0	0	0	0
531	8340	Compressor Station Equip Maint			46,416	21,348	13,552	125	7,076	4,314
532	8350	Meas. & Regul. Station Equip Maint			0	0	0	0	0	0
533	8360	Purification Equipment Maintenance			0	0	0	0	0	0
534	8410	Other storage expenses-Operation labor and expenses			233,243	107,275	68,102	630	35,559	21,677
535		Total Underground Storage Expense			486,338	223,681	142,000	1,314	74,145	45,199
536										
537		Transmission:								
538		Operation								
539	8500	Op., Sup., & Eng.			0	0	0	0	0	0
540	8510	System Control & Load Dispatching			0	0	0	0	0	0
541	8520	Communication Systems Expense			0	0	0	0	0	0
542	8530	Compressor Station Labor Expense			0	0	0	0	0	0
543	8540	Compressor Station Fuel Gas			0	0	0	0	0	0
544	8550	Compressor Station Fuel & Power			488	264	163	0	62	0
545	8560	Mains Expense			145,499	78,563	48,484	0	18,452	0
546	8570	Meas. & Regul. Station Expenses			11,936	6,445	3,977	0	1,514	0
547	8580	LDC Payment			0	0	0	0	0	0
548	8580	LDC Payment - A&G			0	0	0	0	0	0
549	8590	Other Expenses			0	0	0	0	0	0
550	8600	Rents			0	0	0	0	0	0
551		Maintenance								
552	8610	Maint. Sup., & Eng.			0	0	0	0	0	0
553	8620	Structures and Improvements			0	0	0	0	0	0
554	8630	Mains			22,915	12,373	7,636	0	2,906	0
555	8640	Compressor Station Equip Maint			0	0	0	0	0	0
556	8650	Meas. & Regul. Station Equip Maint			0	0	0	0	0	0
557	8660	Communication Equipment Maintenance			0	0	0	0	0	0
558	8670	Other Equipment Maintenance			0	0	0	0	0	0
559		Total Transmission Expense			180,838	97,644	60,261	0	22,934	0

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF O&M EXPENSES

560									
561		Distribution:							
562		Operation							
563	8700	Supervision and Engineering		2,140,705	1,173,665	695,550	571	253,776	17,143
564	8710	Distribution Load Dispatching		(41)	(12)	(9)	(0)	(10)	(11)
565	8711	Odorization		132,819	39,034	28,051	835	31,067	33,833
565	8720	Compressor Station Labor & Expenses		0	0	0	0	0	0
566	8740	Mains & Services		6,802,984	3,673,294	2,266,949	0	862,742	0
567	8750	Measuring and Regulating Station Exp. - Gen		1,361,535	735,165	453,702	0	172,667	0
568	8760	Measuring and Regulating Station Exp. - Ind.		523	0	518	0	3	2
569	8770	Measuring and Regulating Sta. Exp. - City Gate		5,487	2,963	1,829	0	696	0
570	8780	Meters and House Regulator Expense		938,471	653,413	266,517	821	11,060	6,659
571	8790	Customer Installations Expense		257	228	29	0	0	0
572	8800	Other Expense		3,085	1,691	1,002	1	366	25
573	8810	Rents		75,023	41,132	24,376	20	8,894	601
574		Maintenance							
575	8850	Maintenance Supervision and Engineering		0	0	0	0	0	0
576	8860	Maintenance of Structures and Improvements		0	0	0	0	0	0
577	8870	Maintenance of Mains		144,480	78,012	48,145	0	18,323	0
578	8890	Maintenance of compressor station equipment		140,590	41,317	29,692	884	32,884	35,812
579	8900	Maint. of Measuring and Regulating Station Equip. - General		0	0	0	0	0	0
580	8910	Maint. of Measuring and Regulating Station Equip. - Industrial		135	0	133	0	1	0
581	8920	Maint. of Measuring and Regulating Station Equip. - City Gate		178	96	59	0	23	0
582	8930	Maintenance of Services		0	0	0	0	0	0
583	8940	Maintenance of Meters and House Regulators		0	0	0	0	0	0
584	8950	Maintenance of Other Equipment		0	0	0	0	0	0
585		Total Distribution		11,746,231	6,439,999	3,816,544	3,132	1,392,492	94,065
586									
587		Customer Accounts:							
588	9010	Supervision		0	0	0	0	0	0
589	9020	Meter Reading Expense		735,288	652,684	81,800	36	480	289
590	9030	Customer Records and Collection Expenses		1,067,803	947,844	118,792	52	697	419
591	9040	Uncollectible Accounts		731,532	496,144	235,187	0	200	0
592	9050	Miscellaneous Customer Accounts Expenses		0	0	0	0	0	0
593		Total Customer Accounts		2,534,624	2,096,673	435,779	87	1,376	708
594									
595		Customer Service and Information:							
596	9070	Supervision		0	0	0	0	0	0
597	9080	Customer Assistance Expenses		0	0	0	0	0	0
598	9090	Informational and Instructional Advertising Expenses		214,461	190,368	23,859	10	140	84
599	9100	Miscellaneous Customer Service and Informational Expenses		0	0	0	0	0	0
600		Total Customer Service and Information		214,461	190,368	23,859	10	140	84
601									
602		Sales:							
603	9110	Supervision		158,549	140,737	17,638	8	103	62
604	9120	Demonstrating and Selling Expenses		77,078	68,419	8,575	4	50	30
605	9130	Advertising Expenses		36,821	32,685	4,096	2	24	14
606	9160	Miscellaneous Sales Expenses		(188,721)	(167,520)	(20,995)	(9)	(123)	(74)
607		Total Sales		83,728	74,321	9,315	4	55	33
608									
609		Administrative & General:							
610		Operation							
611	9200	Administrative and General Salaries		0	0	0	0	0	0
612	9210	Office Supplies and Expenses		69,069	40,039	21,075	17	7,434	504
613	9220	Administrative Expenses Transferred - Customer Support		0	0	0	0	0	0
614	9220	Administrative Expenses Transferred - General		18,251,309	10,580,157	5,568,991	4,498	1,964,378	133,286
615	9230	Outside Services Employed		69,993	40,574	21,357	17	7,533	511
616	9240	Property Insurance		0	0	0	0	0	0
617	9250	Injuries and Damages		23,257	13,482	7,096	6	2,503	170
618	9260	Employee Pensions and Benefits		872,759	505,932	266,303	215	93,935	6,374
619	9270	Franchise Requirements		635	564	71	0	0	0
620	9280	Regulatory Commission Expenses		165,392	146,811	18,400	8	108	65
621	930.1	General Advertising Expenses		0	0	0	0	0	0
622	930.2	Miscellaneous General Expense		24,411	14,151	7,448	6	2,627	178
623	ADJ	Adjustments		(1,404,321)	(814,075)	(428,498)	(346)	(151,146)	(10,256)
624		Maintenance							
625	9320	Maintenance of General Plant		0	0	0	0	0	0
626		Total A&G		18,072,504	10,527,635	5,482,243	4,421	1,927,372	130,833
627									
628		TOTAL O&M EXPENSE		120,959,622	70,151,559	46,266,542	852,085	3,418,513	270,923

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF DEPRECIATION EXPENSE

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Intangible Plant:								
2										
3	30100	Organization	99.0	-	0	-	-	-	-	-
4	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
5	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
6										
7		Total Intangible Plant:			0	-	-	-	-	-
8										
9		Production Plant:								
10			99.0	-	0	-	-	-	-	-
11	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
12	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
13	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
14	33201	Field Lines	99.0	-	0	-	-	-	-	-
15	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
17	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
18										
19		Total Production Plant			0	-	-	-	-	-
20										
21		Storage Plant:								
22										
23	35010	Land	99.0	-	0	-	-	-	-	-
24	35020	Rights of Way	99.0	-	0	-	-	-	-	-
25	35100	Structures and Improvements	99.0	-	0	-	-	-	-	-
26	35102	Compression Station Equipment	99.0	-	0	-	-	-	-	-
27	35103	Meas. & Reg. Sta. Structues	99.0	-	0	-	-	-	-	-
28	35104	Other Structures	99.0	-	0	-	-	-	-	-
29	35200	Wells \ Rights of Way	99.0	-	0	-	-	-	-	-
30	35201	Well Construction	99.0	-	0	-	-	-	-	-
31	35202	Well Equipment	99.0	-	0	-	-	-	-	-
32	35203	Cushion Gas	99.0	-	0	-	-	-	-	-
33	35210	Leaseholds	99.0	-	0	-	-	-	-	-
34	35211	Storage Rights	99.0	-	0	-	-	-	-	-
35	35301	Field Lines	99.0	-	0	-	-	-	-	-
36	35302	Tributary Lines	99.0	-	0	-	-	-	-	-
37	35400	Compressor Station Equipment	99.0	-	0	-	-	-	-	-
38	35500	Meas & Reg. Equipment	99.0	-	0	-	-	-	-	-
39	35600	Purification Equipment	99.0	-	0	-	-	-	-	-
40										
41		Total Storage Plant			0	-	-	-	-	-
42										
43		Transmission:								
44										
45	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
46	36520	Rights of Way	99.0	-	0	-	-	-	-	-
47	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
48	36603	Other Structues	99.0	-	0	-	-	-	-	-
49	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
50	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
51	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
52	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
53	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
54										
55		Total Transmission Plant			0	-	-	-	-	-
56										
57		Distribution:								
58										
59	37400	Land & Land Rights	2.0	Bills	0	-	-	-	-	-
60	37401	Land	2.0	Bills	0	-	-	-	-	-
61	37402	Land Rights	2.0	Bills	0	-	-	-	-	-
62	37403	Land Other	2.0	Bills	0	-	-	-	-	-
63	37500	Structures & Improvements	2.0	Bills	0	-	-	-	-	-
64	37501	Structures & Improvements T.B.	2.0	Bills	0	-	-	-	-	-
65	37502	Land Rights	2.0	Bills	0	-	-	-	-	-
66	37503	Improvements	2.0	Bills	0	-	-	-	-	-
67	37600	Mains Cathodic Protection	2.0	Bills	0	-	-	-	-	-
68	37601	Mains - Steel	2.0	Bills	0	-	-	-	-	-
69	37602	Mains - Plastic	2.0	Bills	0	-	-	-	-	-
70	37603	Mains - Anodes	2.0	Bills	0	-	-	-	-	-
71	37604	Mains - Leak Clamps	2.0	Bills	0	-	-	-	-	-
72	37800	Meas & Reg. Sta. Equip - General	2.0	Bills	0	-	-	-	-	-
73	37900	Meas & Reg. Sta. Equip - City Gate	2.0	Bills	0	-	-	-	-	-
74	37905	Meas & Reg. Sta. Equipment T.b.	2.0	Bills	0	-	-	-	-	-
75	38000	Services	2.0	Bills	4,814,131	4,273,300	535,566	233	3,141	1,891
76	38100	Meters	4.0	Meter Investment	2,722,922	1,895,843	773,286	2,381	32,091	19,321
77	38200	Meter Installaitons	4.0	Meter Investment	2,026,363	1,410,862	575,469	1,772	23,882	14,378
78	38300	House Regulators	4.0	Meter Investment	124,799	86,892	35,442	109	1,471	886
79	38400	House Reg. Installations	4.0	Meter Investment	12,401	8,635	3,522	11	146	88
80	38500	Ind. Meas. & Reg. Sta. Equipment	2.2	Non-Residential Bills	97,340	-	96,392	42	565	340
81	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
82										
83		Total Distribution Plant			9,797,957	7,675,532	2,019,678	4,548	61,296	36,903

Atmos Energy Corporation, Kentucky/Mid-States Division										
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ALLOCATION OF DEPRECIATION EXPENSE										
84										
85		General:								
86										
87	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
88	39000	Structures Frame	6.2	P, S, T & D Plant - Customer	80,355	64,223	15,463	30	399	240
89	39001	Structures & Improvements	6.2	P, S, T & D Plant - Customer	1,501	1,200	289	1	7	4
90	39002	Improvements	6.2	P, S, T & D Plant - Customer	7,601	6,075	1,463	3	38	23
91	39003	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	197	158	38	0	1	1
92	39004	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
93	39009	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	32,417	25,909	6,238	12	161	97
94	39100	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
95	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
96	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	896	716	172	0	4	3
97	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
98	39202	Trailers	6.2	P, S, T & D Plant - Customer	181	145	35	0	1	1
99	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
100	39500	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	60,435	48,302	11,629	22	300	181
101	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
102	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
103	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
104	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
105	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	10,328	8,255	1,987	4	51	31
106	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
107	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
108	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
109	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	71,146	56,863	13,691	26	353	213
110	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
111	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
112	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
113	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
114	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
115	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
116	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	3,945	3,153	759	1	20	12
117	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
118	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
119	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
120	40600	Amortization of gas plant acquisition adjustments	6.2	P, S, T & D Plant - Customer	17,594	14,062	3,386	6	87	53
121										
122										
123		Total General Plant			286,597	229,061	55,149	106	1,424	857
124										
125		TOTAL DIRECT DEPRECIATION EXPENSE			10,084,554	7,904,593	2,074,827	4,654	62,720	37,761
126										
127		Kentucky Mid-States General Office:								
128										
129		Intangible Plant:								
130										
131	30100	Organization	99.0	-	0	-	-	-	-	-
132	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
133	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
134										
135		Total Intangible Plant:			0	-	-	-	-	-
136										
137		General:								
138										
139	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
140	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	1,407	1,125	271	1	7	4
141	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
142	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
143	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	56	45	11	0	0	0
144	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
145	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	309	247	59	0	2	1
146	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
147	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
148	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	22	18	4	0	0	0
149	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
150	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
151	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
152	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	500	399	96	0	2	1
153	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	4	3	1	0	0	0
154	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
155	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
156	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
157	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
158	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
159	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
160	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
161	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
162	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
163	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
164	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
165	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	554	443	107	0	3	2
166	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
167	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
168	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
169	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
170	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
171	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
172	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
173										
174										
175		Total General Plant			2,851	2,278	549	1	14	9

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF DEPRECIATION EXPENSE										
176										
177		Shared Services General Office:								
178										
179		General:								
180										
181	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
182	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	4,100	3,277	789	2	20	12
183	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
184	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
185	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
186	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	10,243	8,187	1,971	4	51	31
187	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	8,778	7,016	1,689	3	44	26
188	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
189	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
190	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	338	270	65	0	2	1
191	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
192	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
193	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
194	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	61	49	12	0	0	0
195	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
196	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
197	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
198	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
199	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	800	639	154	0	4	2
200	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
201	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
202	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
203	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	138	110	27	0	1	0
204	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
205	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	120,243	96,103	23,138	44	597	360
206	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	78,920	63,076	15,186	29	392	236
207	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	11,835	9,459	2,277	4	59	35
208	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
209	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
210	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	15,278	12,211	2,940	6	76	46
211	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	157	126	30	0	1	0
212	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
213	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	182,278	145,684	35,075	67	906	545
214	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
215	ADJ	WTW Adjustment	6.2	P, S, T & D Plant - Customer	(3,021)	(2,415)	(581)	(1)	(15)	(9)
216										
217		Total General Plant			430,147	343,793	82,773	159	2,137	1,287
218										
219		Shared Services Customer Support:								
220										
221		General:								
222										
223	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
224	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
225	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	9,410	7,521	1,811	3	47	28
226	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
227	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
228	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	2,702	2,160	520	1	13	8
229	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	4,010	3,205	772	1	20	12
230	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
231	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
232	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
233	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
234	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
235	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
236	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	945	756	182	0	5	3
237	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
238	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
239	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
240	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
241	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	2,396	1,915	461	1	12	7
242	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
243	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
244	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
245	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	750	599	144	0	4	2
246	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	423	338	81	0	2	1
247	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	13,762	10,999	2,648	5	68	41
248	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
249	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	1,431	1,143	275	1	7	4
250	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
251	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
252	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	6,664	5,326	1,282	2	33	20
253	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	4	3	1	0	0	0
254	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
255	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	143,560	114,740	27,625	53	713	429
256	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
257										
258										
259		Total General Plant			186,058	148,706	35,803	69	924	556
260										
261	NTB	To Match Schedule C-1	6.2	P, S, T & D Plant - Customer	69	55	13	0	0	0
262										
263		TOTAL DEPRECIATION EXPENSE - CUSTOMER			10,703,678	8,399,424	2,193,964	4,882	65,795	39,612

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
264		Intangible Plant:								
265										
266	30100	Organization	99.0	-	0	-	-	-	-	-
267	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
268	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
269										
270		Total Intangible Plant:			0	-	-	-	-	-
271										
272		Production Plant:								
273			3.0	Peak Day	0	-	-	-	-	-
274	32520	Producing Leaseholds	3.0	Peak Day	0	-	-	-	-	-
275	32540	Rights of Ways	3.0	Peak Day	0	-	-	-	-	-
276	33100	Production Gas Wells Equipment	3.0	Peak Day	0	-	-	-	-	-
277	33201	Field Lines	3.0	Peak Day	0	-	-	-	-	-
278	33202	Tributary Lines	3.0	Peak Day	0	-	-	-	-	-
279	33400	Field Meas. & Reg. Sta. Equip	3.0	Peak Day	0	-	-	-	-	-
280	33600	Purification Equipment	3.0	Peak Day	0	-	-	-	-	-
281										
282		Total Production Plant			0	-	-	-	-	-
283										
284		Storage Plant:								
285										
286	35010	Land	3.0	Peak Day	0	-	-	-	-	-
287	35020	Rights of Way	3.0	Peak Day	16	9	5	-	2	-
288	35100	Structures and Improvements	3.0	Peak Day	147	79	49	-	19	-
289	35102	Compression Station Equipment	3.0	Peak Day	1,531	827	510	-	194	-
290	35103	Meas. & Reg. Sta. Structues	3.0	Peak Day	127	69	42	-	16	-
291	35104	Other Structures	3.0	Peak Day	948	512	316	-	120	-
292	35200	Wells \ Rights of Way	3.0	Peak Day	120,988	65,328	40,317	-	15,344	-
293	35201	Well Construction	3.0	Peak Day	13,600	7,343	4,532	-	1,725	-
294	35202	Well Equipment	3.0	Peak Day	4,605	2,486	1,534	-	584	-
295	35203	Cushion Gas	3.0	Peak Day	11,864	6,406	3,953	-	1,505	-
296	35210	Leaseholds	3.0	Peak Day	500	270	167	-	63	-
297	35211	Storage Rights	3.0	Peak Day	279	150	93	-	35	-
298	35301	Field Lines	3.0	Peak Day	1,105	596	368	-	140	-
299	35302	Tributary Lines	3.0	Peak Day	1,319	712	439	-	167	-
300	35400	Compressor Station Equipment	3.0	Peak Day	154,463	83,403	51,472	-	19,589	-
301	35500	Meas & Reg. Equipment	3.0	Peak Day	2,553	1,379	851	-	324	-
302	35600	Purification Equipment	3.0	Peak Day	16,594	8,960	5,530	-	2,104	-
303										
304		Total Storage Plant			330,639	178,530	110,178	-	41,931	-
305										
306		Transmission:								
307										
308	36510	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
309	36520	Rights of Way	3.0	Peak Day	7,376	3,983	2,458	-	935	-
310	36602	Structures & Improvements	3.0	Peak Day	4,496	2,427	1,498	-	570	-
311	36603	Other Structues	3.0	Peak Day	0	-	-	-	-	-
312	36700	Mains Cathodic Protection	3.0	Peak Day	1,478	798	493	-	187	-
313	36701	Mains - Steel	3.0	Peak Day	384,012	207,348	127,964	-	48,700	-
314	36703	Mains - Anodes	3.0	Peak Day	0	-	-	-	-	-
315	36900	Meas. & Reg. Equipment	3.0	Peak Day	35,793	19,326	11,927	-	4,539	-
316	36901	Meas. & Reg. Equipment	3.0	Peak Day	40,624	21,935	13,537	-	5,152	-
317										
318		Total Transmission Plant			473,778	255,818	157,876	-	60,084	-
319										
320		Distribution:								
321										
322	37400	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
323	37401	Land	3.0	Peak Day	0	-	-	-	-	-
324	37402	Land Rights	3.0	Peak Day	54,464	29,408	18,149	-	6,907	-
325	37403	Land Other	3.0	Peak Day	0	-	-	-	-	-
326	37500	Structures & Improvements	3.0	Peak Day	4,841	2,614	1,613	-	614	-
327	37501	Structures & Improvements T.B.	3.0	Peak Day	1,437	776	479	-	182	-
328	37502	Land Rights	3.0	Peak Day	666	360	222	-	84	-
329	37503	Improvements	3.0	Peak Day	58	31	19	-	7	-
330	37600	Mains Cathodic Protection	3.0	Peak Day	159,292	86,010	53,081	-	20,201	-
331	37601	Mains - Steel	3.0	Peak Day	3,554,207	1,919,106	1,184,363	-	450,738	-
332	37602	Mains - Plastic	3.0	Peak Day	3,416,357	1,844,673	1,138,428	-	433,256	-
333	37603	Mains - Anodes	3.0	Peak Day	200,720	108,379	66,886	-	25,455	-
334	37604	Mains - Leak Clamps	3.0	Peak Day	339,494	183,311	113,129	-	43,054	-
335	37800	Meas & Reg. Sta. Equip - General	3.0	Peak Day	573,607	309,721	191,142	-	72,744	-
336	37900	Meas & Reg. Sta. Equip - City Gate	3.0	Peak Day	214,735	115,947	71,556	-	27,232	-
337	37905	Meas & Reg. Sta. Equipment T.b.	3.0	Peak Day	37,287	20,133	12,425	-	4,729	-
338	38000	Services	99.0	-	0	-	-	-	-	-
339	38100	Meters	99.0	-	0	-	-	-	-	-
340	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
341	38300	House Regulators	99.0	-	0	-	-	-	-	-
342	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
343	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
344	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
345										
346		Total Distribution Plant			8,557,165	4,620,469	2,851,492	-	1,085,204	-

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
347											
348		General:									
349											
350	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
351	39000	Structures Frame	6.4	P, S, T & D Plant - Demand	140,142	75,670	46,699	-	17,773	-	
352	39001	Structures & Improvements	6.4	P, S, T & D Plant - Demand	2,618	1,414	872	-	332	-	
353	39002	Improvements	6.4	P, S, T & D Plant - Demand	13,257	7,158	4,418	-	1,681	-	
354	39003	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	344	186	115	-	44	-	
355	39004	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
356	39009	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	56,537	30,528	18,840	-	7,170	-	
357	39100	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
358	39102	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
359	39103	Transportation Equipment	6.4	P, S, T & D Plant - Demand	1,563	844	521	-	198	-	
360	39200	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
361	39201	Trailers	6.4	P, S, T & D Plant - Demand	316	171	105	-	40	-	
362	39202	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
363	39300	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	105,400	56,911	35,122	-	13,367	-	
364	39400	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
365	39600	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
366	39603	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
367	39604	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
368	39605	Communication Equipment	6.4	P, S, T & D Plant - Demand	18,013	9,726	6,002	-	2,284	-	
369	39700	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
370	39701	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
371	39702	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
372	39705	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	124,082	66,998	41,348	-	15,736	-	
373	39800	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
374	39900	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
375	39901	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
376	39902	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
377	39903	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
378	39904	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
379	39905	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	6,880	3,715	2,293	-	873	-	
380	39906	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
381	39907	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
382	39908	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
383	40600	Amortization of gas plant acquisition adjustments	6.4	P, S, T & D Plant - Demand	30,684	16,568	10,225	-	3,891	-	
384											
385											
386		Total General Plant			499,837	269,889	166,560	0	63,388	0	
387											
388		TOTAL DIRECT DEPRECIATION EXPENSE			9,861,419	5,324,705	3,286,106	0	1,250,607	0	
389											
390		Kentucky Mid-States General Office:									
391											
392		Intangible Plant:									
393											
394	30100	Organization	99.0	-	0	-	-	-	-	-	
395	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
396	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
397											
398		Total Intangible Plant:			0	-	-	-	-	-	
399											
400		General:									
401											
402	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
403	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	2,454	1,325	818	-	311	-	
404	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
405	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
406	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	97	52	32	-	12	-	
407	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
408	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	538	291	179	-	68	-	
409	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
410	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
411	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	38	21	13	-	5	-	
412	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
413	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
414	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
415	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	871	471	290	-	111	-	
416	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	6	3	2	-	1	-	
417	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
418	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
419	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
420	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
421	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
422	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
423	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
424	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
425	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
426	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
427	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
428	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	966	522	322	-	123	-	
429	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
430	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
431	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
432	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
433	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
434	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
435	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
436											
437											
438		Total General Plant			4,972	2,684	1,657	-	630	-	

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
439											
440		Shared Services General Office:									
441											
442		General:									
443											
444	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
445	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	7,150	3,861	2,383	-	907	-	
446	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
447	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
448	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
449	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	17,865	9,646	5,953	-	2,266	-	
450	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	15,310	8,267	5,102	-	1,942	-	
451	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
452	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
453	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	590	319	197	-	75	-	
454	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
455	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
456	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
457	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	106	57	35	-	13	-	
458	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
459	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
460	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
461	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
462	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	1,395	753	465	-	177	-	
463	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
464	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
465	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
466	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	240	130	80	-	30	-	
467	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
468	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	209,709	113,233	69,881	-	26,595	-	
469	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	137,640	74,319	45,865	-	17,455	-	
470	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	20,640	11,145	6,878	-	2,618	-	
471	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
472	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
473	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	26,646	14,387	8,879	-	3,379	-	
474	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	274	148	91	-	35	-	
475	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
476	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	317,900	171,651	105,933	-	40,315	-	
477	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
478	ADJ	WTW Adjustment	6.4	P, S, T & D Plant - Demand	(5,269)	(2,845)	(1,756)	-	(668)	-	
479											
480		Total General Plant			750,194	405,070	249,986	-	95,138	-	
481											
482		Shared Services Customer Support:									
483											
484		General:									
485											
486	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
487	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
488	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	16,412	8,862	5,469	-	2,081	-	
489	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
490	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
491	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	4,712	2,545	1,570	-	598	-	
492	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	6,993	3,776	2,330	-	887	-	
493	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
494	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
495	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
496	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
497	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
498	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
499	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	1,649	890	549	-	209	-	
500	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
501	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
502	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
503	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
504	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	4,179	2,256	1,392	-	530	-	
505	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
506	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
507	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
508	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	1,307	706	436	-	166	-	
509	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	738	398	246	-	94	-	
510	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	24,002	12,960	7,998	-	3,044	-	
511	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
512	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	2,495	1,347	831	-	316	-	
513	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
514	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
515	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	11,623	6,276	3,873	-	1,474	-	
516	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	7	4	2	-	1	-	
517	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
518	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	250,375	135,191	83,432	-	31,752	-	
519	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
520											
521											
522		Total General Plant			324,492	175,211	108,130	-	41,151	-	
523											
524	NTB	To Match Schedule C-1	6.4	P, S, T & D Plant - Demand	120	65	40	-	15	-	
525											
526		TOTAL DEPRECIATION EXPENSE - DEMAND			10,941,196	5,907,735	3,645,919	0	1,387,542	0	

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
527		Intangible Plant:								
528										
529	30100	Organization	99.0	-	0	-	-	-	-	-
530	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
531	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
532										
533		Total Intangible Plant:			0	-	-	-	-	-
534										
535		Production Plant:								
536			99.0	-	0	-	-	-	-	-
537	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
538	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
539	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
540	33201	Field Lines	99.0	-	0	-	-	-	-	-
541	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
542	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
543	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
544										
545		Total Production Plant			0	-	-	-	-	-
546										
547		Storage Plant:								
548										
549	35010	Land	1.5	Winter Volumes	0	-	-	-	-	-
550	35020	Rights of Way	1.5	Winter Volumes	16	6	4	0	3	3
551	35100	Structures and Improvements	1.5	Winter Volumes	147	56	37	1	26	27
552	35102	Compression Station Equipment	1.5	Winter Volumes	1,531	582	384	8	273	285
553	35103	Meas. & Reg. Sta. Structues	1.5	Winter Volumes	127	48	32	1	23	24
554	35104	Other Structures	1.5	Winter Volumes	948	360	238	5	169	176
555	35200	Wells \ Rights of Way	1.5	Winter Volumes	120,988	45,964	30,335	654	21,547	22,489
556	35201	Well Construction	1.5	Winter Volumes	13,600	5,167	3,410	73	2,422	2,528
557	35202	Well Equipment	1.5	Winter Volumes	4,605	1,749	1,155	25	820	856
558	35203	Cushion Gas	1.5	Winter Volumes	11,864	4,507	2,975	64	2,113	2,205
559	35210	Leaseholds	1.5	Winter Volumes	500	190	125	3	89	93
560	35211	Storage Rights	1.5	Winter Volumes	279	106	70	2	50	52
561	35301	Field Lines	1.5	Winter Volumes	1,105	420	277	6	197	205
562	35302	Tributary Lines	1.5	Winter Volumes	1,319	501	331	7	235	245
563	35400	Compressor Station Equipment	1.5	Winter Volumes	154,463	58,681	38,728	834	27,509	28,711
564	35500	Meas & Reg. Equipment	1.5	Winter Volumes	2,553	970	640	14	455	475
565	35600	Purification Equipment	1.5	Winter Volumes	16,594	6,304	4,160	90	2,955	3,084
566										
567		Total Storage Plant			330,639	125,611	82,900	1,786	58,884	61,458
568										
569		Transmission:								
570										
571	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
572	36520	Rights of Way	99.0	-	0	-	-	-	-	-
573	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
574	36603	Other Structues	99.0	-	0	-	-	-	-	-
575	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
576	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
577	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
578	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
579	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
580										
581		Total Transmission Plant			0	-	-	-	-	-
582										
583		Distribution:								
584										
585	37400	Land & Land Rights	99.0	-	0	-	-	-	-	-
586	37401	Land	99.0	-	0	-	-	-	-	-
587	37402	Land Rights	1.0	Mcf	0	-	-	-	-	-
588	37403	Land Other	99.0	-	0	-	-	-	-	-
589	37500	Structures & Improvements	1.0	Mcf	0	-	-	-	-	-
590	37501	Structures & Improvements T.B.	1.0	Mcf	0	-	-	-	-	-
591	37502	Land Rights	1.0	Mcf	0	-	-	-	-	-
592	37503	Improvements	1.0	Mcf	0	-	-	-	-	-
593	37600	Mains Cathodic Protection	1.0	Mcf	0	-	-	-	-	-
594	37601	Mains - Steel	1.0	Mcf	0	-	-	-	-	-
595	37602	Mains - Plastic	1.0	Mcf	0	-	-	-	-	-
596	37603	Mains - Anodes	1.0	Mcf	0	-	-	-	-	-
597	37604	Mains - Leak Clamps	1.0	Mcf	0	-	-	-	-	-
598	37800	Meas & Reg. Sta. Equip - General	1.0	Mcf	0	-	-	-	-	-
599	37900	Meas & Reg. Sta. Equip - City Gate	1.0	Mcf	0	-	-	-	-	-
600	37905	Meas & Reg. Sta. Equipment T.b.	1.0	Mcf	0	-	-	-	-	-
601	38000	Services	99.0	-	0	-	-	-	-	-
602	38100	Meters	99.0	-	0	-	-	-	-	-
603	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
604	38300	House Regulators	99.0	-	0	-	-	-	-	-
605	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
606	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
607	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
608										
609		Total Distribution Plant			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF DEPRECIATION EXPENSE										
610										
611		General:								
612										
613	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
614	39000	Structures Frame	6.6	P, S, T & D Plant - Commodity	4,690	1,782	1,176	25	835	872
615	39001	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	88	33	22	0	16	16
616	39002	Improvements	6.6	P, S, T & D Plant - Commodity	444	169	111	2	79	82
617	39003	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	12	4	3	0	2	2
618	39004	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
619	39009	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	1,892	719	474	10	337	352
620	39100	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
621	39102	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
622	39103	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	52	20	13	0	9	10
623	39200	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
624	39201	Trailers	6.6	P, S, T & D Plant - Commodity	11	4	3	0	2	2
625	39202	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
626	39300	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	3,527	1,340	884	19	628	656
627	39400	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
628	39600	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
629	39603	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
630	39604	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
631	39605	Communication Equipment	6.6	P, S, T & D Plant - Commodity	603	229	151	3	107	112
632	39700	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
633	39701	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
634	39702	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
635	39705	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	4,152	1,578	1,041	22	740	772
636	39800	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
637	39900	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
638	39901	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
639	39902	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
640	39903	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
641	39904	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
642	39905	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	230	87	58	1	41	43
643	39906	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
644	39907	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
645	39908	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
646	40600	Amortization of gas plant acquisition adjustments	6.6	P, S, T & D Plant - Commodity	1,027	390	257	6	183	191
647										
648										
649		Total General Plant			16,727	6,355	4,194	90	2,979	3,109
650										
651		TOTAL DIRECT DEPRECIATION EXPENSE			347,366	131,965	87,094	1,876	61,863	64,567
652										
653		Kentucky Mid-States General Office:								
654										
655		Intangible Plant:								
656										
657	30100	Organization	99.0	-	0	-	-	-	-	-
658	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
659	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
660										
661		Total Intangible Plant:			0	-	-	-	-	-
662										
663		General:								
664										
665	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
666	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	82	31	21	0	15	15
667	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
668	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
669	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	3	1	1	0	1	1
670	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
671	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	18	7	5	0	3	3
672	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
673	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
674	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	1	0	0	0	0	0
675	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
676	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
677	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
678	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	29	11	7	0	5	5
679	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
680	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
681	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
682	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
683	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
684	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
685	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
686	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
687	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
688	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
689	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
690	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
691	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	32	12	8	0	6	6
692	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
693	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
694	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
695	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
696	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
697	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
698	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
699										
700										
701		Total General Plant			166	63	42	1	30	31
702										
703		Shared Services General Office:								

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Demand - Only Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF DEPRECIATION EXPENSE										
704										
705		General:								
706										
707	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
708	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	239	91	60	1	43	44
709	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
710	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
711	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
712	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	598	227	150	3	106	111
713	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	512	195	128	3	91	95
714	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
715	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
716	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	20	8	5	0	4	4
717	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
718	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
719	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
720	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	4	1	1	0	1	1
721	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
722	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
723	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
724	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
725	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	47	18	12	0	8	9
726	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
727	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
728	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
729	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	8	3	2	0	1	1
730	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
731	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	7,018	2,666	1,760	38	1,250	1,304
732	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	4,606	1,750	1,155	25	820	856
733	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	691	262	173	4	123	128
734	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
735	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
736	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	892	339	224	5	159	166
737	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	9	3	2	0	2	2
738	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
739	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	10,639	4,042	2,667	57	1,895	1,977
740	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
741	ADJ	WTW Adjustment	6.6	P, S, T & D Plant - Commodity	(176)	(67)	(44)	(1)	(31)	(33)
742										
743		Total General Plant			25,105	9,538	6,295	136	4,471	4,666
744										
745		Shared Services Customer Support:								
746										
747		General:								
748										
749	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
750	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
751	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	549	209	138	3	98	102
752	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
753	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
754	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	158	60	40	1	28	29
755	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	234	89	59	1	42	44
756	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
757	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
758	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
759	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
760	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
761	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
762	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	55	21	14	0	10	10
763	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
764	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
765	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
766	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
767	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	140	53	35	1	25	26
768	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
769	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
770	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
771	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	44	17	11	0	8	8
772	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	25	9	6	0	4	5
773	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	803	305	201	4	143	149
774	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
775	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	83	32	21	0	15	16
776	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
777	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
778	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	389	148	98	2	69	72
779	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
780	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
781	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	8,379	3,183	2,101	45	1,492	1,557
782	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
783										
784										
785		Total General Plant			10,859	4,125	2,723	59	1,934	2,018
786										
787	NTB	To Match Schedule C-1	6.6	P, S, T & D Plant - Commodity	4	2	1	0	1	1
788										
789		TOTAL DEPRECIATION EXPENSE - COMMODITY			383,501	145,693	96,154	2,072	68,299	71,284

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Total Depreciation Expense

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
790		Intangible Plant:								
791										
792	30100	Organization			0	-	-	-	-	-
793	30200	Franchises & Consents			0	-	-	-	-	-
794	30300	Misc Intangible Plant			0	-	-	-	-	-
795										
796		Total Intangible Plant:			0	-	-	-	-	-
797										
798		Production Plant:								
799					0	-	-	-	-	-
800	32520	Producing Leaseholds			0	-	-	-	-	-
801	32540	Rights of Ways			0	-	-	-	-	-
802	33100	Production Gas Wells Equipment			0	-	-	-	-	-
803	33201	Field Lines			0	-	-	-	-	-
804	33202	Tributary Lines			0	-	-	-	-	-
805	33400	Field Meas. & Reg. Sta. Equip			0	-	-	-	-	-
806	33600	Purification Equipment			0	-	-	-	-	-
807										
808		Total Production Plant			0	-	-	-	-	-
809										
810		Storage Plant:								
811										
812	35010	Land			0	-	-	-	-	-
813	35020	Rights of Way			32	15	9	0	5	3
814	35100	Structures and Improvements			294	135	86	1	45	27
815	35102	Compression Station Equipment			3,062	1,408	894	8	467	285
816	35103	Meas. & Reg. Sta. Structues			255	117	74	1	39	24
817	35104	Other Structures			1,897	872	554	5	289	176
818	35200	Wells \ Rights of Way			241,977	111,292	70,652	654	36,891	22,489
819	35201	Well Construction			27,200	12,510	7,942	73	4,147	2,528
820	35202	Well Equipment			9,210	4,236	2,689	25	1,404	856
821	35203	Cushion Gas			23,728	10,913	6,928	64	3,617	2,205
822	35210	Leaseholds			1,000	460	292	3	152	93
823	35211	Storage Rights			557	256	163	2	85	52
824	35301	Field Lines			2,209	1,016	645	6	337	205
825	35302	Tributary Lines			2,637	1,213	770	7	402	245
826	35400	Compressor Station Equipment			308,927	142,084	90,200	834	47,098	28,711
827	35500	Meas & Reg. Equipment			5,107	2,349	1,491	14	779	475
828	35600	Purification Equipment			33,187	15,264	9,690	90	5,060	3,084
829										
830		Total Storage Plant			661,278	304,140	193,078	1,786	100,815	61,458
831										
832		Transmission:								
833										
834	36510	Land & Land Rights			0	-	-	-	-	-
835	36520	Rights of Way			7,376	3,983	2,458	-	935	-
836	36602	Structures & Improvements			4,496	2,427	1,498	-	570	-
837	36603	Other Structues			0	-	-	-	-	-
838	36700	Mains Cathodic Protection			1,478	798	493	-	187	-
839	36701	Mains - Steel			384,012	207,348	127,964	-	48,700	-
840	36703	Mains - Anodes			0	-	-	-	-	-
841	36900	Meas. & Reg. Equipment			35,793	19,326	11,927	-	4,539	-
842	36901	Meas. & Reg. Equipment			40,624	21,935	13,537	-	5,152	-
843										
844		Total Transmission Plant			473,778	255,818	157,876	-	60,084	-
845										
846		Distribution:								
847										
848	37400	Land & Land Rights			0	-	-	-	-	-
849	37401	Land			0	-	-	-	-	-
850	37402	Land Rights			54,464	29,408	18,149	-	6,907	-
851	37403	Land Other			0	-	-	-	-	-
852	37500	Structures & Improvements			4,841	2,614	1,613	-	614	-
853	37501	Structures & Improvements T.B.			1,437	776	479	-	182	-
854	37502	Land Rights			666	360	222	-	84	-
855	37503	Improvements			58	31	19	-	7	-
856	37600	Mains Cathodic Protection			159,292	86,010	53,081	-	20,201	-
857	37601	Mains - Steel			3,554,207	1,919,106	1,184,363	-	450,738	-
858	37602	Mains - Plastic			3,416,357	1,844,673	1,138,428	-	433,256	-
859	37603	Mains - Anodes			200,720	108,379	66,886	-	25,455	-
860	37604	Mains - Leak Clamps			339,494	183,311	113,129	-	43,054	-
861	37800	Meas & Reg. Sta. Equip - General			573,607	309,721	191,142	-	72,744	-
862	37900	Meas & Reg. Sta. Equip - City Gate			214,735	115,947	71,556	-	27,232	-
863	37905	Meas & Reg. Sta. Equipment T.b.			37,287	20,133	12,425	-	4,729	-
864	38000	Services			4,814,131	4,273,300	535,566	233	3,141	1,891
865	38100	Meters			2,722,922	1,895,843	773,286	2,381	32,091	19,321
866	38200	Meter Installaitons			2,026,363	1,410,862	575,469	1,772	23,882	14,378
867	38300	House Regulators			124,799	86,892	35,442	109	1,471	886
868	38400	House Reg. Installations			12,401	8,635	3,522	11	146	88
869	38500	Ind. Meas. & Reg. Sta. Equipment			97,340	-	96,392	42	565	340
870	38600	Other Prop. On Cust. Prem			0	-	-	-	-	-
871										
872		Total Distribution Plant			18,355,122	12,296,001	4,871,169	4,548	1,146,500	36,903

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
873											
874		General:									
875											
876	38900	Land & Land Rights			0	-	-	-	-	-	
877	39000	Structures Frame			225,186	141,675	63,338	55	19,007	1,112	
878	39001	Structures & Improvements			4,207	2,647	1,183	1	355	21	
879	39002	Improvements			21,302	13,402	5,992	5	1,798	105	
880	39003	Air Conditioning Equipment			553	348	156	0	47	3	
881	39004	Improvement to leased Premises			0	-	-	-	-	-	
882	39009	Office Furniture & Equipment			90,847	57,156	25,552	22	7,668	449	
883	39100	Remittance Processing Equip			0	-	-	-	-	-	
884	39102	Office Machines			0	-	-	-	-	-	
885	39103	Transportation Equipment			2,511	1,580	706	1	212	12	
886	39200	Trucks			0	-	-	-	-	-	
887	39201	Trailers			508	320	143	0	43	3	
888	39202	Stores Equipment			0	-	-	-	-	-	
889	39300	Tools, Shop & Garage Equipment			169,362	106,553	47,636	41	14,295	836	
890	39400	Power Operated Equipment			0	-	-	-	-	-	
891	39600	Ditchers			0	-	-	-	-	-	
892	39603	Backhoes			0	-	-	-	-	-	
893	39604	Welders			0	-	-	-	-	-	
894	39605	Communication Equipment			28,944	18,210	8,141	7	2,443	143	
895	39700	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
896	39701	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
897	39702	Communication Equip. - Telemetering			0	-	-	-	-	-	
898	39705	Miscellaneous Equipment			199,380	125,439	56,079	49	16,829	985	
899	39800	Other Tangible Property			0	-	-	-	-	-	
900	39900	Other Tangible Property - Servers - H/W			0	-	-	-	-	-	
901	39901	Other Tangible Property - Servers - S/W			0	-	-	-	-	-	
902	39902	Other Tangible Property - Network - H/W			0	-	-	-	-	-	
903	39903	Other Tang. Property - CPU			0	-	-	-	-	-	
904	39904	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
905	39905	Other Tang. Property - PC Hardware			11,055	6,955	3,110	3	933	55	
906	39906	Other Tang. Property - PC Software			0	-	-	-	-	-	
907	39907	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
908	39908	Other Tang. Property - Application Software			0	-	-	-	-	-	
909	40600	Amortization of gas plant acquisition adjustments			49,305	31,020	13,868	12	4,162	243	
910											
911											
912		Total General Plant			803,161	505,304	225,903	196	67,791	3,966	
913											
914		TOTAL DIRECT DEPRECIATION EXPENSE			20,293,339	13,361,264	5,448,027	6,530	1,375,190	102,328	
915											
916		Kentucky Mid-States General Office:									
917											
918		Intangible Plant:									
919											
920	30100	Organization			0	-	-	-	-	-	
921	30200	Franchises & Consents			0	-	-	-	-	-	
922	30300	Misc Intangible Plant			0	-	-	-	-	-	
923											
924		Total Intangible Plant:			0	-	-	-	-	-	
925											
926		General:									
927											
928	37400	Land & Land Rights			0	-	-	-	-	-	
929	39001	Structures Frame			3,943	2,481	1,109	1	333	19	
930	36602	Structures & Improvements			0	-	-	-	-	-	
931	38900	Land & Land Rights			0	-	-	-	-	-	
932	39004	Air Conditioning Equipment			156	98	44	0	13	1	
933	39009	Improvement to leased Premises			0	-	-	-	-	-	
934	39100	Office Furniture & Equipment			865	544	243	0	73	4	
935	39102	Remittance Processing Equip			0	-	-	-	-	-	
936	39103	Office Machines			0	-	-	-	-	-	
937	39200	Transportation Equipment			62	39	17	0	5	0	
938	39201	Trucks			0	-	-	-	-	-	
939	39202	Trailers			0	-	-	-	-	-	
940	39300	Stores Equipment			0	-	-	-	-	-	
941	39400	Tools, Shop & Garage Equipment			1,400	881	394	0	118	7	
942	39600	Power Operated Equipment			10	6	3	0	1	0	
943	39603	Ditchers			0	-	-	-	-	-	
944	39604	Backhoes			0	-	-	-	-	-	
945	39605	Welders			0	-	-	-	-	-	
946	39700	Communication Equipment			0	-	-	-	-	-	
947	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
948	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
949	39705	Communication Equip. - Telemetering			0	-	-	-	-	-	
950	39800	Miscellaneous Equipment			0	-	-	-	-	-	
951	39900	Other Tangible Property			0	-	-	-	-	-	
952	39901	Other Tangible Property - Servers - H/W			0	-	-	-	-	-	
953	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-	
954	39903	Other Tangible Property - Network - H/W			1,552	977	437	0	131	8	
955	39904	Other Tang. Property - CPU			0	-	-	-	-	-	
956	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
957	39906	Other Tang. Property - PC Hardware			0	-	-	-	-	-	
958	39907	Other Tang. Property - PC Software			0	-	-	-	-	-	
959	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
960	39909	Other Tang. Property - Application Software			0	-	-	-	-	-	
961	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-	
962											
963											
964		Total General Plant			7,989	5,026	2,247	2	674	39	
965											
966		Shared Services General Office:									

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Demand - Only Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
967											
968		General:									
969											
970	37400	Land & Land Rights			0	-	-	-	-	-	
971	39000	Structures & Improvements			11,489	7,228	3,231	3	970	57	
972	36602	Structures & Improvements			0	-	-	-	-	-	
973	37503	Improvements			0	-	-	-	-	-	
974	39004	Air Conditioning Equipment			0	-	-	-	-	-	
975	39009	Improvement to leased Premises			28,706	18,060	8,074	7	2,423	142	
976	39100	Office Furniture & Equipment			24,600	15,477	6,919	6	2,076	121	
977	39102	Remittance Processing Equip			0	-	-	-	-	-	
978	39103	Office Machines			0	-	-	-	-	-	
979	39200	Transportation Equipment			948	597	267	0	80	5	
980	39201	Trucks			0	-	-	-	-	-	
981	39202	Trailers			0	-	-	-	-	-	
982	39300	Stores Equipment			0	-	-	-	-	-	
983	39400	Tools, Shop & Garage Equipment			171	108	48	0	14	1	
984	39600	Power Operated Equipment			0	-	-	-	-	-	
985	39603	Ditchers			0	-	-	-	-	-	
986	39604	Backhoes			0	-	-	-	-	-	
987	39605	Welders			0	-	-	-	-	-	
988	39700	Communication Equipment			2,242	1,410	631	1	189	11	
989	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
990	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
991	39705	Communication Equip. - Telemetering			0	-	-	-	-	-	
992	39800	Miscellaneous Equipment			386	243	109	0	33	2	
993	39900	Other Tangible Property			0	-	-	-	-	-	
994	39901	Other Tangible Property - Servers - H/W			336,969	212,002	94,779	82	28,442	1,664	
995	39902	Other Tangible Property - Servers - S/W			221,166	139,145	62,207	54	18,668	1,092	
996	39903	Other Tangible Property - Network - H/W			33,165	20,866	9,328	8	2,799	164	
997	39904	Other Tang. Property - CPU			0	-	-	-	-	-	
998	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
999	39906	Other Tang. Property - PC Hardware			42,815	26,937	12,043	10	3,614	211	
1000	39907	Other Tang. Property - PC Software			440	277	124	0	37	2	
1001	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
1002	39909	Other Tang. Property - Application Software			510,816	321,377	143,676	125	43,116	2,523	
1003	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-	
1004	ADJ	WTW Adjustment			(8,467)	(5,327)	(2,381)	(2)	(715)	(42)	
1005											
1006		Total General Plant			1,205,447	758,400	339,053	294	101,746	5,953	
1007											
1008		Shared Services Customer Support:									
1009											
1010		General:									
1011											
1012	37400	Land & Land Rights			0	-	-	-	-	-	
1013	39001	Structures Frame			0	-	-	-	-	-	
1014	36602	Structures & Improvements			26,371	16,591	7,417	6	2,226	130	
1015	37503	Improvements			0	-	-	-	-	-	
1016	39004	Air Conditioning Equipment			0	-	-	-	-	-	
1017	39009	Improvement to leased Premises			7,572	4,764	2,130	2	639	37	
1018	39100	Office Furniture & Equipment			11,237	7,070	3,161	3	948	55	
1019	39102	Remittance Processing Equip			0	-	-	-	-	-	
1020	39103	Office Machines			0	-	-	-	-	-	
1021	39200	Transportation Equipment			0	-	-	-	-	-	
1022	39201	Trucks			0	-	-	-	-	-	
1023	39202	Trailers			0	-	-	-	-	-	
1024	39300	Stores Equipment			0	-	-	-	-	-	
1025	39400	Tools, Shop & Garage Equipment			2,649	1,667	745	1	224	13	
1026	39600	Power Operated Equipment			0	-	-	-	-	-	
1027	39603	Ditchers			0	-	-	-	-	-	
1028	39604	Backhoes			0	-	-	-	-	-	
1029	39605	Welders			0	-	-	-	-	-	
1030	39700	Communication Equipment			6,715	4,224	1,889	2	567	33	
1031	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
1032	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
1033	39705	Communication Equip. - Telemetering			0	-	-	-	-	-	
1034	39800	Miscellaneous Equipment			2,101	1,322	591	1	177	10	
1035	39900	Other Tangible Property			1,186	746	334	0	100	6	
1036	39901	Other Tangible Property - Servers - H/W			38,567	24,264	10,848	9	3,255	190	
1037	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-	
1038	39903	Other Tangible Property - Network - H/W			4,009	2,522	1,128	1	338	20	
1039	39904	Other Tang. Property - CPU			0	-	-	-	-	-	
1040	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
1041	39906	Other Tang. Property - PC Hardware			18,676	11,750	5,253	5	1,576	92	
1042	39907	Other Tang. Property - PC Software			11	7	3	0	1	0	
1043	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
1044	39909	Other Tang. Property - Application Software			402,314	253,114	113,158	98	33,957	1,987	
1045	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-	
1046											
1047											
1048		Total General Plant			521,409	328,042	146,656	127	44,010	2,575	
1049											
1050	NTB	To Match Schedule C-1			192	121	54	0	16	1	
1051											
1052		TOTAL DEPRECIATION EXPENSE			22,028,375	14,452,852	5,936,037	6,953	1,521,636	110,896	

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Customer

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Taxes Other Than Income								
2									
3	Non Revenue Related:								
4	Payroll Related	7.2	Allocated O&M Expenses - Cust	23,054	18,342	4,529	8	110	66
5	Property Related	6.2	P, S, T & D Plant - Customer	4,419,838	3,532,529	850,503	1,629	21,957	13,219
6	DOT transmission User Tax	7.2	Allocated O&M Expenses - Cust	14,275	11,357	2,804	5	68	41
7	Other	7.2	Allocated O&M Expenses - Cust	27,253	21,683	5,353	10	130	78
8	Total Non Revenue Related:			4,484,419	3,583,912	863,189	1,652	22,264	13,403
9									
10	Revenue Related:								
11	State Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
12	Local Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
13	Public Service Commission Assessment	99.0	-	0	-	-	-	-	-
14	Total Revenue Related:			0	-	-	-	-	-
15									
16	Total Taxes, Other Than Income			4,484,419	3,583,912	863,189	1,652	22,264	13,403
17									
18									
19	Interest Expense	19.2	Rate Base - Cust	3,344,439	2,726,279	593,890	1,074	14,478	8,717
20									
21	Amortization of COS and Depreciation Reserves	20.2	Cost of Service - Cust	(434,546)	(349,188)	(82,109)	(150)	(2,105)	(994)
22									
23	Amortization of Excess ADIT	20.2	Cost of Service - Cust	(37,725)	(30,315)	(7,128)	(13)	(183)	(86)

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Demand

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
20	Taxes Other Than Income								
21									
22	Non Revenue Related:								
23	Payroll Related	7.4	Allocated O&M Expenses - Demand	77,251	41,712	25,742	-	9,797	-
24	Property Related	6.4	P, S, T & D Plant - Demand	7,708,375	4,162,163	2,568,651	-	977,562	-
25	DOT transmission User Tax	7.4	Allocated O&M Expenses - Demand	47,834	25,828	15,940	-	6,066	-
26	Other	7.4	Allocated O&M Expenses - Demand	91,322	49,310	30,431	-	11,581	-
27	Total Non Revenue Related:			7,924,783	4,279,013	2,640,764	0	1,005,006	0
28									
29	Revenue Related:								
30	State Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
31	Local Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
32	Public Service Commission Assessment	99.0	-	0	-	-	-	-	-
33	Total Revenue Related:			0	-	-	-	-	-
34									
35	Total Taxes, Other Than Income			7,924,783	4,279,013	2,640,764	-	1,005,006	-
36									
37									
38	Interest Expense	19.4	Rate Base - Demand	6,590,984	3,558,824	2,196,304	-	835,857	-
39									
40	Amortization of COS and Depreciation Reserves	20.4	Cost of Service - Demand	(848,250)	(458,567)	(282,743)	15	(107,522)	566
41									
42	Amortization of Excess ADIT	20.4	Cost of Service - Demand	(73,641)	(39,811)	(24,547)	1	(9,335)	49

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Commodity

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
39	Taxes Other Than Income								
40									
41	Non Revenue Related:								
42	Payroll Related	7.6	Allocated O&M Expenses - Comm	275,647	157,983	113,529	2,640	719	776
43	Property Related	6.6	P, S, T & D Plant - Commodity	257,961	98,000	64,677	1,393	45,941	47,949
44	DOT transmission User Tax	7.6	Allocated O&M Expenses - Comm	170,681	97,823	70,297	1,635	445	481
45	Other	7.6	Allocated O&M Expenses - Comm	325,857	186,759	134,209	3,121	849	918
46	Total Non Revenue Related:			1,030,146	540,565	382,713	8,790	47,954	50,124
47									
48	Revenue Related:								
49	State Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
50	Local Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
51	Public Service Commission Assessment	1.0	Mcf	291,875	85,778	61,643	1,836	68,270	74,350
52	Total Revenue Related:			291,875	85,778	61,643	1,836	68,270	74,350
53									
54	Total Taxes, Other Than Income			1,322,021	626,343	444,356	10,626	116,224	124,473
55									
56									
57	Interest Expense	19.6	Rate Base - Comm	304,927	90,530	60,164	1,511	73,954	78,768
58									
59	Amortization of COS and Depreciation Reserves	20.6	Cost of Service - Comm	(905,722)	(511,723)	(367,282)	(8,550)	(8,784)	(9,383)
60									
61	Amortization of Excess ADIT	20.6	Cost of Service - Comm	(78,631)	(44,426)	(31,886)	(742)	(763)	(815)

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Total Taxes Other

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
58	Taxes Other Than Income								
59									
60	Non Revenue Related:								
61	Payroll Related			375,952	218,037	143,800	2,648	10,625	842
62	Property Related			12,386,174	7,792,692	3,483,832	3,023	1,045,460	61,168
63	DOT transmission User Tax			232,790	135,009	89,041	1,640	6,579	521
64	Other			444,432	257,752	169,993	3,131	12,560	995
65	Total Non Revenue Related:			13,439,348	8,403,490	3,886,666	10,441	1,075,224	63,527
66									
67	Revenue Related:								
68	State Gross Receipts - Tax			0	-	-	-	-	-
69	Con Local Gross Receipts - Tax			0	-	-	-	-	-
70	Public Service Commission Assessment			291,875	85,778	61,643	1,836	68,270	74,350
71	Total Revenue Related:			291,875	85,778	61,643	1,836	68,270	74,350
72									
73	Total Taxes, Other Than Income			13,731,224	8,489,267	3,948,309	12,277	1,143,494	137,876
74									
75									
76	Interest Expense			10,240,350	6,375,633	2,850,358	2,586	924,289	87,485
77									
78	Amortization of COS and Depreciation Reserves			(2,188,517)	(1,319,477)	(732,133)	(8,686)	(118,410)	(9,811)
79									
80	Amortization of Excess ADIT			(189,998)	(114,551)	(63,561)	(754)	(10,280)	(852)

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF REVENUES

Total Revenues

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Rate Schedule Revenue:								
2									
3	Base Revenues	Input		96,636,506	52,550,517	26,407,052	226,254	9,273,095	8,179,588
4	Base Revenue Increase	Input		0	-	-	-	-	-
5	Gas Costs	Input		87,640,898	50,501,238	36,296,543	843,117	-	-
6	Rider FF and Rider Tax	Input		0	-	-	-	-	-
7									
8	Total Rate Schedule Revenue			184,277,404	103,051,755	62,703,595	1,069,371	9,273,095	8,179,588
9									
10	Other Revenue:								
11									
12	Forfeited Discounts	18.6	Total Rate Schedule Revenues	367,462	205,492	125,035	2,132	18,491	16,311
13	Misc. Service Revenues	18.6	Total Rate Schedule Revenues	58,912	32,945	20,046	342	2,965	2,615
14	NTB	18.2	Base Revenues	(5)	(2)	(1)	(0)	(0)	(0)
15	Other Gas Revenue	18.2	Base Revenues	3,118,240	1,695,685	852,095	7,301	299,222	263,937
16									
17	Total Non-Rate Revenue			3,544,609	1,934,120	997,175	9,775	320,677	282,862
18									
19	TOTAL REVENUE			187,822,013	104,985,875	63,700,770	1,079,146	9,593,772	8,462,450

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION FACTORS

			Total Company	Customer	Demand	Commodity
	Input	Values	1	1	0	0
1.0	Customer	%	100.0000%	100.0000%	0.0000%	0.0000%
	Input	Values	1	0	1	0
2.0	Demand	%	100.0000%	0.0000%	100.0000%	0.0000%
	Input	Values	1	0	0	1
3.0	Commodity	%	100.0000%	0.0000%	0.0000%	100.0000%
	Input	Values	100	0	50	50
3.5	Storage (50/50)	%	100.0000%	0.0000%	50.0000%	50.0000%
	Input	Values	100	-	100	0
4.0	Mains (All Demand)	%	100.0000%	0.0000%	100.0000%	0.0000%
	Internally Generated	Values	549,923,660	155,087,701	394,835,959	0
4.1	Mains & Services	%	100.0000%	28.2017%	71.7983%	0.0000%
	Internally Generated	Values	901,469,328	321,677,069	561,017,801	18,774,458
5.4	P, S, T & D Plant	%	100.0000%	35.6836%	62.2337%	2.0827%
	Internally Generated	Values	733,894,161	242,111,038	475,967,374	15,815,749
5.7	Net Plant	%	100.0000%	32.9899%	64.8550%	2.1550%
	Internally Generated	Values	120,959,622	7,417,382	24,854,938	88,687,302
9.1	Allocated O&M Expenses	%	100.0000%	6.1321%	20.5481%	73.3198%
	Internally Generated	Values	9,527,418	939,386	8,314,664	273,368
10.0	Composite of Accts. 871-879 & 886-893	%	100.0000%	9.8598%	87.2709%	2.8693%
	Internally Generated	Values	431,755,369	-	431,755,369	-
12.0	Composite of Accts. 374-379	%	100.0000%	0.0000%	100.0000%	0.0000%
	Internally Generated	Values	628,233,491	205,177,426	404,349,163	18,706,901
13.0	Rate Base	%	100.0000%	32.6594%	64.3629%	2.9777%
	Internally Generated	Values	12,945,100	2,357,025	10,251,043	337,032
17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	%	100.0000%	18.2079%	79.1886%	2.6035%
	Internally Generated	Values	223,201,833	44,318,316	86,511,041	92,372,476
18.0	Total Cost of Service at Equalized ROR	%	100.0000%	19.8557%	38.7591%	41.3852%
		Values	0	0	0	0
99.0	-	%	0.0000%	0.0000%	0.0000%	0.0000%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION FACTORS

			Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
	Input	Value	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
1.0	Mcf	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	17,293,508	9,938,593	7,142,201	212,715	-	-
1.2	Sales Mcf	%	100.0000%	57.4701%	41.2999%	1.2300%	0.0000%	0.0000%
	Input	Value	20,198,212	7,673,367	5,064,215	109,105	3,597,159	3,754,366
1.5	Winter Volumes	%	100.0000%	37.9903%	25.0726%	0.5402%	17.8093%	18.5876%
	Input	Value	2,169,218	1,925,523	241,323	105	1,415	852
2.0	Bills	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	243,695	0	241,323	105	1,415	852
2.2	Non-Residential Bills	%	100.0000%	0.0000%	99.0266%	0.0431%	0.5807%	0.3496%
	Input	Value	242,043	130,692	80,656	0	30,695	0
3.0	Peak Day	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Input	Value	85,443,836	59,490,553	24,265,293	74,716	1,007,003	606,271
4.0	Meter Investment	%	100.0000%	69.6253%	28.3991%	0.0874%	1.1786%	0.7096%
	Input	Value	1	1	-	-	-	-
4.2	Direct to Residential	%	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Input	Value	1	-	1	-	-	-
4.4	Direct to Non-Res Sales Firm	%	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
	Input	Value	1	-	-	1	-	-
4.6	Direct to Non-Res Sales Interruptible	%	100.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
	Input	Value	1	-	-	-	1	-
4.8	Direct to Transport Firm	%	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
	Input	Value	1	-	-	-	-	1
5.0	Direct to Transport Interruptible	%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Internally Generated	Value	901,469,328	567,154,403	253,554,280	219,981	76,088,854	4,451,810
6.0	P, S, T & D Plant	%	100.0000%	62.9144%	28.1268%	0.0244%	8.4405%	0.4938%
	Internally Generated	Value	321,677,069	257,098,521	61,899,891	118,567	1,598,004	962,086
6.2	P, S, T & D Plant - Customer	%	100.0000%	79.9244%	19.2429%	0.0369%	0.4968%	0.2991%
	Internally Generated	Value	561,017,801	302,923,403	186,947,146	0	71,147,252	0
6.4	P, S, T & D Plant - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	18,774,458	7,132,478	4,707,243	101,414	3,343,599	3,489,724
6.6	P, S, T & D Plant - Commodity	%	100.0000%	37.9903%	25.0726%	0.5402%	17.8093%	18.5876%
	Internally Generated	Value	120,959,622	70,151,559	46,266,542	852,085	3,418,513	270,923
7.0	Allocated O&M Expenses	%	100.0000%	57.9958%	38.2496%	0.7044%	2.8262%	0.2240%
	Internally Generated	Value	7,417,382	5,901,377	1,457,017	2,602	35,271	21,115
7.2	Allocated O&M Expenses - Cust	%	100.0000%	79.5615%	19.6433%	0.0351%	0.4755%	0.2847%
	Internally Generated	Value	24,854,938	13,420,505	8,282,375	0	3,152,058	0
7.4	Allocated O&M Expenses - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	88,687,302	50,829,677	36,527,151	849,483	231,184	249,808
7.6	Allocated O&M Expenses - Comm	%	100.0000%	57.3134%	41.1864%	0.9578%	0.2607%	0.2817%
	Input	Value	1,173,349	795,796	377,232	0	321	0
8.0	Customer Deposit Balances	%	100.0000%	67.8227%	32.1500%	0.0000%	0.0273%	0.0000%
	Internally Generated	Value	733,894,161	460,424,807	205,514,297	162,976	64,223,096	3,568,984
9.0	Allocated Net Plant	%	100.0000%	62.7372%	28.0033%	0.0222%	8.7510%	0.4863%
	Internally Generated	Value	242,111,038	197,416,206	42,942,963	77,544	1,045,111	629,214
9.2	Allocated Net Plant - Cust	%	100.0000%	81.5395%	17.7369%	0.0320%	0.4317%	0.2599%
	Internally Generated	Value	475,967,374	257,000,146	158,605,916	0	60,361,312	0
9.4	Allocated Net Plant - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	15,815,749	6,008,455	3,965,418	85,432	2,816,674	2,939,771
9.6	Allocated Net Plant - Comm	%	100.0000%	37.9903%	25.0726%	0.5402%	17.8093%	18.5876%
	Internally Generated	Value	9,527,418	5,223,511	3,095,615	2,540	1,129,456	76,296
10.0	Composite of Accts. 871-879 & 886-893	%	100.0000%	54.8261%	32.4916%	0.0267%	11.8548%	0.8008%
	Internally Generated	Value	939,386	653,642	267,197	821	11,064	6,661
10.2	Composite of Accts. 871-879 & 886-893 - Cust	%	100.0000%	69.5818%	28.4438%	0.0874%	1.1778%	0.7091%
	Internally Generated	Value	8,314,664	4,489,530	2,770,683	0	1,054,451	0
10.4	Composite of Accts. 871-879 & 886-893 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	273,368	80,338	57,734	1,719	63,941	69,635
10.6	Composite of Accts. 871-879 & 886-893 - Comm	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	549,923,660	350,857,750	148,823,939	7,507	50,173,550	60,914
11.0	Composite of Accts. 376 & 380	%	100.0000%	63.8012%	27.0627%	0.0014%	9.1237%	0.0111%
	Internally Generated	Value	155,087,701	137,664,778	17,253,327	7,507	101,176	60,914
11.2	Composite of Accts. 376 & 380 - Cust	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	394,835,959	213,192,972	131,570,613	0	50,072,374	0
11.4	Composite of Accts. 376 & 380 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
11.6	Composite of Accts. 376 & 380 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Demand - Only Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION FACTORS

			Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
	Internally Generated	Value	431,755,369	233,127,729	143,873,214	-	54,754,426	-
12.0	Composite of Accts. 374-379	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
12.2	Composite of Accts. 374-379 - Cust	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	431,755,369	233,127,729	143,873,214	0	54,754,426	0
12.4	Composite of Accts. 374-379 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
12.6	Composite of Accts. 374-379 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	74,469,926	51,849,932	21,148,799	65,120	877,669	528,405
13.0	Composite of Accts. 381-383	%	100.0000%	69.6253%	28.3991%	0.0874%	1.1786%	0.7096%
	Internally Generated	Value	74,469,926	51,849,932	21,148,799	65,120	877,669	528,405
13.2	Composite of Accts. 381-383 - Cust	%	100.0000%	69.6253%	28.3991%	0.0874%	1.1786%	0.7096%
	Internally Generated	Value	0	0	0	0	0	0
13.4	Composite of Accts. 381-383 - Demand	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
13.6	Composite of Accts. 381-383 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	155,087,701	137,664,778	17,253,327	7,507	101,176	60,914
14.0	Account 380	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	155,087,701	137,664,778	17,253,327	7,507	101,176	60,914
14.2	Account 380 - Cust	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	0	0	0	0	0	0
14.4	Account 380 - Demand	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
14.6	Account 380 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	12,945,100	7,504,184	3,949,916	3,190	1,393,274	94,536
17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	%	100.0000%	57.9693%	30.5128%	0.0246%	10.7629%	0.7303%
	Internally Generated	Value	2,357,025	1,870,051	462,797	1,070	14,423	8,684
17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	%	100.0000%	79.3395%	19.6348%	0.0454%	0.6119%	0.3684%
	Internally Generated	Value	10,251,043	5,535,084	3,415,940	0	1,300,018	0
17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	337,032	99,048	71,179	2,120	78,832	85,852
17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	187,822,013	104,985,875	63,700,770	1,079,146	9,593,772	8,462,450
18.0	Revenues	%	100.0000%	55.8965%	33.9155%	0.5746%	5.1079%	4.5056%
	Internally Generated	Value	96,636,506	52,550,517	26,407,052	226,254	9,273,095	8,179,588
18.2	Base Revenues	%	100.0000%	54.3796%	27.3262%	0.2341%	9.5959%	8.4643%
	Internally Generated	Value	87,640,898	50,501,238	36,296,543	843,117	-	-
18.4	Gas Costs	%	100.0000%	57.6229%	41.4151%	0.9620%	0.0000%	0.0000%
	Internally Generated	Value	184,277,404	103,051,755	62,703,595	1,069,371	9,273,095	8,179,588
18.6	Total Rate Schedule Revenues	%	100.0000%	55.9221%	34.0267%	0.5803%	5.0321%	4.4387%
	Internally Generated	Value	628,233,491	391,137,597	174,866,150	158,618	56,704,051	5,367,075
19.0	Rate Base	%	100.0000%	62.2599%	27.8346%	0.0252%	9.0260%	0.8543%
	Internally Generated	Value	205,177,426	167,254,050	36,434,468	65,905	888,233	534,770
19.2	Rate Base - Cust	%	100.0000%	81.5168%	17.7575%	0.0321%	0.4329%	0.2606%
	Internally Generated	Value	404,349,163	218,329,658	134,740,684	0	51,278,821	0
19.4	Rate Base - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	18,706,901	5,553,889	3,690,998	92,713	4,536,997	4,832,304
19.6	Rate Base - Comm	%	100.0000%	29.6890%	19.7307%	0.4956%	24.2531%	25.8317%
	Internally Generated	Value	223,201,833	134,570,436	74,668,603	885,833	12,076,362	1,000,598
20.0	Cost of Service	%	100.0000%	60.2909%	33.4534%	0.3969%	5.4105%	0.4483%
	Internally Generated	Value	44,318,316	35,612,847	8,374,064	15,347	214,644	101,414
20.2	Cost of Service - Cust	%	100.0000%	80.3569%	18.8953%	0.0346%	0.4843%	0.2288%
	Internally Generated	Value	86,511,041	46,768,138	28,836,280	(1,505)	10,965,885	(57,758)
20.4	Cost of Service - Demand	%	100.0000%	54.0603%	33.3325%	-0.0017%	12.6757%	-0.0668%
	Internally Generated	Value	92,372,476	52,189,452	37,458,259	871,991	895,833	956,942
20.6	Cost of Service - Comm	%	100.0000%	56.4989%	40.5513%	0.9440%	0.9698%	1.0360%
	Internally Generated	Value	216,905,276	137,765,358	61,914,953	69,043	16,029,484	1,126,437
21.0	Depreciation Reserve	%	100.0000%	63.5141%	28.5447%	0.0318%	7.3901%	0.5193%
	Internally Generated	Value	97,168,809	73,751,233	22,344,207	47,511	640,339	385,519
21.2	Depreciation Reserve - Cust	%	100.0000%	75.9001%	22.9952%	0.0489%	0.6590%	0.3968%
	Internally Generated	Value	115,750,384	62,499,800	38,571,332	0	14,679,252	0
21.4	Depreciation Reserve - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	3,986,083	1,514,326	999,414	21,532	709,893	740,918
21.6	Depreciation Reserve - Comm	%	100.0000%	37.9903%	25.0726%	0.5402%	17.8093%	18.5876%
		Value	0	0	0	0	0	0
99.0	-	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF RESULTS

			Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
			$					
Operating Revenues			187,822,013	104,985,875	63,700,770	1,079,146	9,593,772	8,462,450
Operating Expenses:								
Operating & Maintenance			120,959,622	67,850,323	45,125,285	910,909	4,419,948	2,653,157
Depreciation & Amortization			22,028,375	13,511,899	5,469,387	31,006	1,931,114	1,084,969
Taxes Other Than Income			13,731,224	7,810,816	3,611,843	29,620	1,438,737	840,207
Total Operating Expenses			156,719,221	89,173,039	54,206,515	971,534	7,789,799	4,578,334
Income Before Taxes			31,102,792	15,812,837	9,494,255	107,612	1,803,973	3,884,116
Interest Expense			10,240,350	5,792,599	2,561,213	17,489	1,178,010	691,040
Income Taxes:								
State Income Taxes		5.00%	1,043,122	501,012	346,652	4,506	31,298	159,654
Federal Income Taxes		21.00%	4,162,057	1,999,037	1,383,142	17,980	124,880	637,019
Total Deferred Income Taxes			0	0	0	0	0	0
Amortization of ITC			0	0	0	0	0	0
Total Income Taxes			5,205,179	2,500,049	1,729,794	22,486	156,178	796,672
Net Income			25,897,613	13,312,787	7,764,461	85,126	1,647,795	3,087,444
Total Rate Base			628,233,491	355,369,153	157,127,414	1,072,923	72,269,502	42,394,499
Rate of Return			4.1223%	3.7462%	4.9415%	7.9341%	2.2801%	7.2827%
Relative Rate of Return			1.00	0.91	1.20	1.92	0.55	1.77
Equalized ROR:			52,143,380	29,495,640	13,041,575	89,053	5,998,369	3,518,743
Net Income Increase			26,245,767	16,182,852	5,277,114	3,926	4,350,574	431,300
Uncollectibles/PSC Fees Increase		1.1554%	408,778	252,048	82,191	61	67,760	6,718
Income Taxes			8,725,275	5,379,909	1,754,350	1,305	1,446,327	143,384
Gross Revenue After Increase			223,201,833	126,800,685	70,814,426	1,084,439	15,458,433	9,043,850
Revenue Deficiency			35,379,820	21,814,810	7,113,656	5,293	5,864,661	581,401
Rate of Return			8.3000%	8.3000%	8.3000%	8.3000%	8.3000%	8.3000%
Relative Rate of Return			1.00	1.00	1.00	1.00	1.00	1.00
Percent Increase			18.8369%	20.7788%	11.1673%	0.4905%	61.1299%	6.8704%
Proposed Rate Levels:								
Net Income Increase			26,245,662	14,909,209	5,905,961	65,857	3,229,532	2,135,103
Uncollectibles/PSC Fees Increase			408,777	232,211	91,985	1,026	50,300	33,254
Income Taxes			8,725,240	4,956,492	1,963,408	21,894	1,073,642	709,804
Gross Revenue After Increase			223,201,693	125,083,788	71,662,124	1,167,924	13,947,246	11,340,611
Revenue Deficiency			35,379,679	20,097,912	7,961,354	88,777	4,353,474	2,878,162
Rate of Return			8.3000%	7.9416%	8.7002%	14.0722%	6.7488%	12.3189%
Relative Rate of Return			1.00	0.96	1.05	1.70	0.81	1.48
Percent Increase			18.8368%	19.1434%	12.4981%	8.2266%	45.3781%	34.0110%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF CUSTOMER COSTS

		Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
		$					
1	Rate Base	205,177,426	167,254,050	36,434,468	65,905	888,233	534,770
2							
3	Return @ Realized ROR	8,458,011	6,458,185	1,922,331	16,074	(398,200)	459,622
4	O&M Expenses	7,417,382	5,901,377	1,457,017	2,602	35,271	21,115
5	Depreciation Expense	10,703,678	8,399,424	2,193,964	4,882	65,795	39,612
6	Taxes, Other	4,484,419	3,583,912	863,189	1,652	22,264	13,403
7							
8	Interest Expense	3,344,439	2,726,279	593,890	1,074	14,478	8,717
9							
10	Income Taxes:						
11							
12	State Income Taxes	340,678	248,628	88,504	999	(27,494)	30,040
13	Federal Income Taxes	1,359,304	992,025	353,130	3,987	(109,699)	119,861
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	1,699,981	1,240,653	441,633	4,986	(137,193)	149,901
18							
19	Total Customer-Related Costs @ Realized ROR	32,763,472	25,583,551	6,878,134	30,196	(412,063)	683,653
20	Total Customers	180,768	160,460	20,110	9	118	71
21	Customer Costs ($/customer/month)	$ 15.10	$ 13.29	$ 28.50	$ 287.58	$ (291.18)	$ 802.41
22							
23							
24	Incremental Return @ Equalized ROR	8,571,716	7,423,901	1,101,730	(10,604)	471,924	(415,236)
25	Incremental Income Taxes	2,849,624	2,468,039	366,265	(3,525)	156,889	(138,043)
26	Incremental Uncollectibles/PSC Fees Increase	133,505	115,627	17,159	(165)	7,350	(6,467)
27							
28	Total Customer-Related Costs @ Equalized ROR	44,318,316	35,591,119	8,363,289	15,902	224,100	123,907
29	Customers	180,768	160,460	20,110	9	118	71
30	Dollars/Customer/Month	$ 20.43	$ 18.48	$ 34.66	$ 151.45	$ 158.36	$ 145.43
31							
32							
33	Incremental Return @ Proposed Rates	8,571,682	7,007,928	1,307,110	9,623	105,802	141,219
34	Incremental Income Taxes	2,849,613	2,329,751	434,542	3,199	35,173	46,947
35	Incremental Uncollectibles/PSC Fees Increase	133,504	109,149	20,358	150	1,648	2,199
36							
37	Total Customer-Related Costs @ Proposed Rates	44,318,270	35,030,379	8,640,145	43,168	(269,440)	874,019
38	Customers	180,768	160,460	20,110	9	118	71
39	Dollars/Customer/Month	$ 20.43	$ 18.19	$ 35.80	$ 411.12	$ (190.40)	$ 1,025.84

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF DEMAND COSTS

		Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
		$					
1	Rate Base	258,989,835	139,842,412	86,302,806	0	32,844,617	0
2							
3	Return @ Realized ROR	10,676,315	5,213,712	4,088,307	16,860	805,095	552,342
4	O&M Expenses	15,502,949	8,370,868	5,166,025	0	1,966,056	0
5	Depreciation Expense	7,117,258	3,842,987	2,371,674	0	902,598	0
6	Taxes, Other	5,167,627	2,790,277	1,722,001	0	655,349	0
7							
8	Interest Expense	4,221,594	2,279,463	1,406,756	0	535,375	0
9							
10	Income Taxes:						
11							
12	State Income Taxes	430,028	195,486	178,651	1,123	17,969	36,798
13	Federal Income Taxes	1,715,812	779,990	712,817	4,482	71,698	146,825
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	2,145,840	975,476	891,468	5,605	89,667	183,623
18							
19	Total Demand-Related Costs @ Realized ROR	40,609,989	21,193,320	14,239,475	22,465	4,418,764	735,965
20							
21							
22	Incremental Return @ Equalized ROR	10,819,841	6,393,208	3,074,826	(16,860)	1,921,009	(552,342)
23	Incremental Income Taxes	3,597,003	2,125,390	1,022,211	(5,605)	638,630	(183,623)
24	Incremental Uncollectibles/PSC Fees Increase	168,519	99,574	47,890	(263)	29,920	(8,603)
25							
26	Total Demand-Related Costs @ Equalized ROR	55,195,353	29,811,494	18,384,402	(263)	7,008,322	(8,603)
27							
28							
29	Incremental Return @ Proposed Rates	10,819,798	5,868,149	3,334,065	8,671	1,458,858	150,056
30	Incremental Income Taxes	3,596,988	1,950,837	1,108,393	2,883	484,990	49,885
31	Incremental Uncollectibles/PSC Fees Increase	168,519	91,397	51,928	135	22,722	2,337
32							
33	Total Demand-Related Costs @ Proposed Rates	55,195,295	29,103,703	18,733,862	34,154	6,385,333	938,243

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

SUMMARY OF COMMODITY COSTS

		Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
		$					
1	Rate Base	164,066,229	48,272,691	34,390,140	1,007,019	38,536,651	41,859,728
2							
3	Return @ Realized ROR	6,763,288	1,989,941	1,417,662	41,512	1,588,593	1,725,580
4	O&M Expenses	98,039,291	53,578,078	38,502,243	908,306	2,418,621	2,632,042
5	Depreciation Expense	4,207,439	1,269,488	903,750	26,124	962,721	1,045,356
6	Taxes, Other	4,079,177	1,436,627	1,026,653	27,968	761,125	826,804
7							
8	Interest Expense	2,674,317	786,856	560,567	16,415	628,156	682,323
9							
10	Income Taxes:						
11							
12	State Income Taxes	272,416	80,152	57,102	1,672	63,986	69,504
13	Federal Income Taxes	1,086,941	319,807	227,835	6,672	255,306	277,321
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	1,359,358	399,960	284,937	8,344	319,292	346,825
18							
19	Total Commodity-Related Costs	114,448,552	58,674,094	42,135,244	1,012,254	6,050,352	6,576,609
20	Total Throughput	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
21	Commodity Costs ($/Mcf)		$ 5.90366	$ 5.89948	$ 4.75875	$ 0.76489	$ 0.76
22							
23							
24	Incremental Return @ Equalized ROR	6,854,209	2,016,693	1,436,720	42,070	1,609,949	1,748,778
25	Incremental Income Taxes	2,278,648	670,439	477,630	13,986	535,220	581,372
26	Incremental Uncollectibles/PSC Fees Increase	106,754	31,410	22,377	655	25,075	27,237
27							
28	Total Commodity-Related Costs @ Equalized ROR	123,688,164	61,392,636	44,071,971	1,068,966	8,220,595	8,933,996
29	Total Throughput	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
30	Commodity Costs ($/Mcf)	$ 3.66	$ 6.18	$ 6.17	$ 5.03	$ 1.04	$ 1.04
31							
32							
33	Incremental Return @ Proposed Rates	6,854,182	1,684,082	1,600,947	58,244	1,317,180	2,193,729
34	Incremental Income Taxes	2,278,639	559,865	532,227	19,363	437,890	729,294
35	Incremental Uncollectibles/PSC Fees Increase	106,754	26,230	24,935	907	20,515	34,167
36							
37	Total Commodity-Related Costs @ Proposed Rates	123,688,128	60,944,270	44,293,353	1,090,768	7,825,937	9,533,799
38	Total Throughput	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
39	Commodity Costs ($/Mcf)	$ 3.66	$ 6.13	$ 6.20	$ 5.13	$ 0.99	$ 1.11

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

TOTAL COST OF SERVICE

		Total Company $	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Rate Base	628,233,491	355,369,153	157,127,414	1,072,923	72,269,502	42,394,499
2							
3	Return @ Realized ROR	25,897,613	13,661,837	7,428,299	74,446	1,995,487	2,737,543
4	O&M Expenses	120,959,622	67,850,323	45,125,285	910,909	4,419,948	2,653,157
5	Depreciation Expense	22,028,375	13,511,899	5,469,387	31,006	1,931,114	1,084,969
6	Taxes, Other	13,731,224	7,810,816	3,611,843	29,620	1,438,737	840,207
7							
8	Interest Expense	10,240,350	5,792,599	2,561,213	17,489	1,178,010	691,040
9							
10	Income Taxes:						
11							
12	State Income Taxes	1,043,122	524,266	324,256	3,795	54,462	136,343
13	Federal Income Taxes	4,162,057	2,091,823	1,293,782	15,140	217,304	544,007
14	Deferred Income Taxes	0	0	0	0	0	0
15	Amortization of ITC	0	0	0	0	0	0
16							
17	Total Income Taxes	5,205,179	2,616,089	1,618,039	18,935	271,766	680,350
18							
19	Total Cost of Service @ Realized ROR	187,822,013	105,450,965	63,252,853	1,064,915	10,057,053	7,996,227
20							
21							
22	Incremental Return @ Equalized ROR	26,245,767	15,833,802	5,613,276	14,607	4,002,881	781,200
23	Incremental Income Taxes	8,725,275	5,263,869	1,866,106	4,856	1,330,738	259,706
24	Incremental Uncollectibles/PSC Fees Increase	408,778	246,612	87,427	228	62,345	12,167
25							
26	Total Cost of Service @ Equalized ROR	223,201,833	126,795,249	70,819,662	1,084,605	15,453,017	9,049,300
27							
28							
29	Incremental Return @ Proposed Rates	26,245,662	14,560,158	6,242,123	76,538	2,881,840	2,485,003
30	Incremental Income Taxes	8,725,240	4,840,452	2,075,163	25,445	958,053	826,127
31	Incremental Uncollectibles/PSC Fees Increase	408,777	226,775	97,221	1,192	44,885	38,704
32							
33	Total Cost of Service @ Proposed Rates	223,201,693	125,078,351	71,667,360	1,168,090	13,941,831	11,346,061

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF GROSS PLANT IN SERVICE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Intangible Plant:						
2								
3	30100	Organization	8,330	5.4	P, S, T & D Plant	2,972	3,384	1,973
4	30200	Franchises & Consents	119,853	5.4	P, S, T & D Plant	42,768	48,698	28,387
5	30300	Misc Intangible Plant	-	99.0	-	-	-	-
6								
7		Total Intangible Plant:	128,182			45,740	52,082	30,360
8								
9		Production Plant:						
10								
11	32520	Producing Leaseholds	-	99.0	-	-	-	-
12	32540	Rights of Ways	-	99.0	-	-	-	-
13	33100	Production Gas Wells Equipment	-	99.0	-	-	-	-
14	33201	Field Lines	-	99.0	-	-	-	-
15	33202	Tributary Lines	-	99.0	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	-	99.0	-	-	-	-
17	33600	Purification Equipment	-	99.0	-	-	-	-
18								
19		Total Production Plant	-			0	0	0
20								
21		Storage Plant:						
22								
23	35010	Land	261,127	3.5	Storage (50/50)	-	130,563	130,563
24	35020	Rights of Way	4,682	3.5	Storage (50/50)	-	2,341	2,341
25	35100	Structures and Improvements	17,916	3.5	Storage (50/50)	-	8,958	8,958
26	35102	Compression Station Equipment	223,508	3.5	Storage (50/50)	-	111,754	111,754
27	35103	Meas. & Reg. Sta. Structues	23,138	3.5	Storage (50/50)	-	11,569	11,569
28	35104	Other Structures	137,443	3.5	Storage (50/50)	-	68,721	68,721
29	35200	Wells \ Rights of Way	12,534,611	3.5	Storage (50/50)	-	6,267,306	6,267,306
30	35201	Well Construction	1,699,999	3.5	Storage (50/50)	-	849,999	849,999
31	35202	Well Equipment	667,359	3.5	Storage (50/50)	-	333,680	333,680
32	35203	Cushion Gas	1,694,833	3.5	Storage (50/50)	-	847,416	847,416
33	35210	Leaseholds	178,530	3.5	Storage (50/50)	-	89,265	89,265
34	35211	Storage Rights	54,614	3.5	Storage (50/50)	-	27,307	27,307
35	35301	Field Lines	175,350	3.5	Storage (50/50)	-	87,675	87,675
36	35302	Tributary Lines	209,319	3.5	Storage (50/50)	-	104,659	104,659
37	35400	Compressor Station Equipment	18,065,905	3.5	Storage (50/50)	-	9,032,953	9,032,953
38	35500	Meas & Reg. Equipment	273,084	3.5	Storage (50/50)	-	136,542	136,542
39	35600	Purification Equipment	1,327,498	3.5	Storage (50/50)	-	663,749	663,749
40								
41		Total Storage Plant	37,548,916			0	18,774,458	18,774,458
42								
43		Transmission:						
44								
45	36510	Land & Land Rights	26,970	2.0	Demand	-	26,970	-
46	36520	Rights of Way	867,772	2.0	Demand	-	867,772	-
47	36602	Structures & Improvements	397,833	2.0	Demand	-	397,833	-
48	36603	Other Structues	60,826	2.0	Demand	-	60,826	-
49	36700	Mains Cathodic Protection	47,233	2.0	Demand	-	47,233	-
50	36701	Mains - Steel	27,826,921	2.0	Demand	-	27,826,921	-
51	36703	Mains - Anodes	11,134	2.0	Demand	-	11,134	-
52	36900	Meas. & Reg. Equipment	1,999,587	2.0	Demand	-	1,999,587	-
53	36901	Meas. & Reg. Equipment	2,269,499	2.0	Demand	-	2,269,499	-
54								
55		Total Transmission Plant	33,507,777			0	33,507,777	0
56								
57		Distribution:						
58								
59	37400	Land & Land Rights	613,356	4.0	Mains (Peak and Average)	-	378,568	234,788
60	37401	Land	428,640	4.0	Mains (Peak and Average)	-	264,560	164,081
61	37402	Land Rights	4,157,536	4.0	Mains (Peak and Average)	-	2,566,061	1,591,476
62	37403	Land Other	2,784	4.0	Mains (Peak and Average)	-	1,718	1,066
63	37500	Structures & Improvements	336,168	4.0	Mains (Peak and Average)	-	207,485	128,683
64	37501	Structures & Improvements T.B.	99,818	4.0	Mains (Peak and Average)	-	61,608	38,210
65	37502	Land Rights	46,264	4.0	Mains (Peak and Average)	-	28,555	17,710
66	37503	Improvements	4,005	4.0	Mains (Peak and Average)	-	2,472	1,533
67	37600	Mains Cathodic Protection	3,418,283	4.0	Mains (Peak and Average)	-	2,109,788	1,308,495
68	37601	Mains - Steel	230,553,919	4.0	Mains (Peak and Average)	-	142,299,497	88,254,422
69	37602	Mains - Plastic	221,659,304	4.0	Mains (Peak and Average)	-	136,809,678	84,849,626
70	37603	Mains - Anodes	3,599,610	4.0	Mains (Peak and Average)	-	2,221,705	1,377,906
71	37604	Mains - Leak Clamps	6,789,879	4.0	Mains (Peak and Average)	-	4,190,761	2,599,118
72	37800	Meas & Reg. Sta. Equip - General	25,594,946	4.0	Mains (Peak and Average)	-	15,797,380	9,797,566
73	37900	Meas & Reg. Sta. Equip - City Gate	9,712,761	4.0	Mains (Peak and Average)	-	5,994,784	3,717,977
74	37905	Meas & Reg. Sta. Equipment T.b.	1,718,293	4.0	Mains (Peak and Average)	-	1,060,543	657,751
75	38000	Services	193,916,542	1.0	Customer	193,916,542	-	-
76	38100	Meters	55,920,540	1.0	Customer	55,920,540	-	-
77	38200	Meter Installations	61,761,518	1.0	Customer	61,761,518	-	-
78	38300	House Regulators	3,974,497	1.0	Customer	3,974,497	-	-
79	38400	House Reg. Installations	378,094	1.0	Customer	378,094	-	-
80	38500	Ind. Meas. & Reg. Sta. Equipment	5,725,878	1.0	Customer	5,725,878	-	-
81	38600	Other Prop. On Cust. Prem	-	99.0	-	-	-	-
82								
83		Total Distribution Plant	830,412,635			321,677,069	313,995,162	194,740,405
84								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF GROSS PLANT IN SERVICE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
85		General:						
86								
87	38900	Land & Land Rights	1,211,697	5.4	P, S, T & D Plant	432,378	492,327	286,993
88	39000	Structures & Improvements	9,256,964	5.4	P, S, T & D Plant	3,303,222	3,761,212	2,192,531
89	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
90	39002	Structures-Brick	173,115	5.4	P, S, T & D Plant	61,774	70,339	41,003
91	39003	Improvements	876,634	5.4	P, S, T & D Plant	312,815	356,187	207,633
92	39004	Air Conditioning Equipment	12,955	5.4	P, S, T & D Plant	4,623	5,264	3,068
93	39009	Improvement to leased Premises	1,267,195	5.4	P, S, T & D Plant	452,181	514,876	300,138
94	39100	Office Furniture & Equipment	1,816,939	5.4	P, S, T & D Plant	648,350	738,243	430,346
95	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
96	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
97	39200	Transportation Equipment	180,749	5.4	P, S, T & D Plant	64,498	73,440	42,811
98	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
99	39202	Trailers	36,588	5.4	P, S, T & D Plant	13,056	14,866	8,666
100	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
101	39400	Tools, Shop & Garage Equipment	7,143,379	5.4	P, S, T & D Plant	2,549,018	2,902,437	1,691,924
102	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
103	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
104	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
105	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
106	39700	Communication Equipment	433,938	5.4	P, S, T & D Plant	154,845	176,314	102,779
107	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
108	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
109	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
110	39800	Miscellaneous Equipment	2,982,913	5.4	P, S, T & D Plant	1,064,412	1,211,992	706,509
111	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
112	39901	Other Tangible Property - Servers - H/W	21,425	5.4	P, S, T & D Plant	7,645	8,705	5,075
113	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
114	39903	Other Tangible Property - Network - H/W	-	5.4	P, S, T & D Plant	-	-	-
115	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
116	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
117	39906	Other Tang. Property - PC Hardware	530,662	5.4	P, S, T & D Plant	189,359	215,614	125,688
118	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
119	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
120	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
121	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
122								
123		Total General Plant	25,945,153			9,258,175	10,541,815	6,145,163
124								
125		TOTAL DIRECT PLANT	927,542,664			330,980,984	376,871,294	219,690,386
126								
127		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
128								
129		Kentucky Mid-States General Office:						
130								
131		Intangible Plant:						
132								
133	30100	Organization	92,599	5.4	P, S, T & D Plant	33,043	37,624	21,932
134	30200	Franchises & Consents	-	5.4	P, S, T & D Plant	-	-	-
135	30300	Misc Intangible Plant	554,443	5.4	P, S, T & D Plant	197,845	225,277	131,321
136								
137		Total Intangible Plant:	647,042			230,888	262,901	153,253
138								
139		General:						
140								
141	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
142	39001	Structures Frame	89,615	5.4	P, S, T & D Plant	31,978	36,412	21,226
143	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
144	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
145	39004	Air Conditioning Equipment	7,687	5.4	P, S, T & D Plant	2,743	3,123	1,821
146	39009	Improvement to leased Premises	19,405	5.4	P, S, T & D Plant	6,925	7,885	4,596
147	39100	Office Furniture & Equipment	13,456	5.4	P, S, T & D Plant	4,802	5,467	3,187
148	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
149	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
150	39200	Transportation Equipment	2,054	5.4	P, S, T & D Plant	733	834	486
151	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
152	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
153	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
154	39400	Tools, Shop & Garage Equipment	55,081	5.4	P, S, T & D Plant	19,655	22,380	13,046
155	39600	Power Operated Equipment	4,736	5.4	P, S, T & D Plant	1,690	1,924	1,122
156	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
157	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
158	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
159	39700	Communication Equipment	-	5.4	P, S, T & D Plant	-	-	-
160	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
161	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
162	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
163	39800	Miscellaneous Equipment	-	5.4	P, S, T & D Plant	-	-	-
164	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
165	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
166	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
167	39903	Other Tangible Property - Network - H/W	14,125	5.4	P, S, T & D Plant	5,040	5,739	3,345
168	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
169	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
170	39906	Other Tang. Property - PC Hardware	-	5.4	P, S, T & D Plant	-	-	-
171	39907	Other Tang. Property - PC Software	21,748	5.4	P, S, T & D Plant	7,760	8,836	5,151
172	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
173	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
174	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
175								
176		Total General Plant	227,907			81,326	92,601	53,980
177								
178		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
179								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF GROSS PLANT IN SERVICE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
180		Shared Services General Office:						
181								
182		General:						
183								
184	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
185	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
186	36602	Structures & Improvements	483,221	5.4	P, S, T & D Plant	172,431	196,338	114,452
187	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
188	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
189	39009	Improvement to leased Premises	642,376	5.4	P, S, T & D Plant	229,223	261,005	152,148
190	39100	Office Furniture & Equipment	384,176	5.4	P, S, T & D Plant	137,088	156,095	90,993
191	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
192	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
193	39200	Transportation Equipment	14,389	5.4	P, S, T & D Plant	5,135	5,847	3,408
194	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
195	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
196	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
197	39400	Tools, Shop & Garage Equipment	1,375	5.4	P, S, T & D Plant	491	559	326
198	39500	Tools, Shop & Garage Equipment	-	5.4	P, S, T & D Plant	-	-	-
199	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
200	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
201	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
202	39700	Communication Equipment	35,202	5.4	P, S, T & D Plant	12,561	14,303	8,338
203	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
204	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
205	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
206	39800	Miscellaneous Equipment	5,516	5.4	P, S, T & D Plant	1,968	2,241	1,306
207	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
208	39901	Other Tangible Property - Servers - H/W	2,628,270	5.4	P, S, T & D Plant	937,862	1,067,896	622,511
209	39902	Other Tangible Property - Servers - S/W	2,115,244	5.4	P, S, T & D Plant	754,796	859,448	501,000
210	39903	Other Tangible Property - Network - H/W	292,050	5.4	P, S, T & D Plant	104,214	118,663	69,173
211	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
212	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
213	39906	Other Tang. Property - PC Hardware	214,855	5.4	P, S, T & D Plant	76,668	87,298	50,889
214	39907	Other Tang. Property - PC Software	3,774	5.4	P, S, T & D Plant	1,347	1,534	894
215	39908	Other Tang. Property - Mainframe S/W	4,940,307	5.4	P, S, T & D Plant	1,762,881	2,007,304	1,170,122
216	39909	Other Tang. Property - Application Software	1,654,844	5.4	P, S, T & D Plant	590,509	672,382	391,953
217	39931	Other Tang. Property - ALGN	799,338	5.4	P, S, T & D Plant	285,233	324,780	189,325
218								
219		Total General Plant	14,214,939			5,072,408	5,775,694	3,366,838
220								
221		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
222								
223		Shared Services Customer Support:						
224								
225		General:						
226								
227	37400	Land & Land Rights	211,229	5.4	P, S, T & D Plant	75,374	85,825	50,030
228	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
229	36602	Structures & Improvements	1,107,950	5.4	P, S, T & D Plant	395,357	450,173	262,420
230	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
231	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
232	39009	Improvement to leased Premises	170,931	5.4	P, S, T & D Plant	60,995	69,451	40,485
233	39100	Office Furniture & Equipment	176,418	5.4	P, S, T & D Plant	62,952	71,681	41,785
234	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
235	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
236	39200	Transportation Equipment	2,237	5.4	P, S, T & D Plant	798	909	530
237	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
238	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
239	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
240	39400	Tools, Shop & Garage Equipment	21,259	5.4	P, S, T & D Plant	7,586	8,638	5,035
241	39510	Laboratory Equip	-	5.4	P, S, T & D Plant	-	-	-
242	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
243	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
244	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
245	39700	Communication Equipment	105,908	5.4	P, S, T & D Plant	37,792	43,032	25,085
246	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
247	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
248	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
249	39800	Miscellaneous Equipment	29,842	5.4	P, S, T & D Plant	10,649	12,125	7,068
250	39900	Other Tangible Property	8,234	5.4	P, S, T & D Plant	2,938	3,346	1,950
251	39901	Other Tangible Property - Servers - H/W	304,635	5.4	P, S, T & D Plant	108,705	123,777	72,153
252	39902	Other Tangible Property - Servers - S/W	98,374	5.4	P, S, T & D Plant	35,104	39,971	23,300
253	39903	Other Tangible Property - Network - H/W	35,543	5.4	P, S, T & D Plant	12,683	14,441	8,418
254	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
255	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
256	39906	Other Tang. Property - PC Hardware	93,706	5.4	P, S, T & D Plant	33,438	38,074	22,195
257	39907	Other Tang. Property - PC Software	98	5.4	P, S, T & D Plant	35	40	23
258	39908	Other Tang. Property - Mainframe S/W	5,800,519	5.4	P, S, T & D Plant	2,069,836	2,356,818	1,373,865
259	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
260	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
261								
262		Total General Plant	8,166,885			2,914,242	3,318,300	1,934,343
263								
264		CWIP w/o AFUDC	-	5.4	P, S, T & D Plant	-	-	-
265								
266		TOTAL PLANT IN SERVICE	950,799,437			339,279,847	386,320,789	225,198,801
267								
268		TOTAL CWIP W/O AFUDC	-			0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Intangible Plant:						
2								
3	30100	Organization	8,330	5.4	P, S, T & D Plant	2,972	3,384	1,973
4	30200	Franchises & Consents	119,853	5.4	P, S, T & D Plant	42,768	48,698	28,387
5	30300	Misc Intangible Plant	-	99.0	-	-	-	-
6								
7		Total Intangible Plant:	128,182			45,740	52,082	30,360
8								
9		Production Plant:						
10								
11	32520	Producing Leaseholds	-	99.0	-	-	-	-
12	32540	Rights of Ways	-	99.0	-	-	-	-
13	33100	Production Gas Wells Equipment	-	99.0	-	-	-	-
14	33201	Field Lines	-	99.0	-	-	-	-
15	33202	Tributary Lines	-	99.0	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	-	99.0	-	-	-	-
17	33600	Purification Equipment	-	99.0	-	-	-	-
18								
19		Total Production Plant	-			0	0	0
20								
21		Storage Plant:						
22								
23	35010	Land	-	3.5	Storage (50/50)	-	-	-
24	35020	Rights of Way	4,200	3.5	Storage (50/50)	-	2,100	2,100
25	35100	Structures and Improvements	7,863	3.5	Storage (50/50)	-	3,931	3,931
26	35102	Compression Station Equipment	120,440	3.5	Storage (50/50)	-	60,220	60,220
27	35103	Meas. & Reg. Sta. Structues	20,864	3.5	Storage (50/50)	-	10,432	10,432
28	35104	Other Structures	106,003	3.5	Storage (50/50)	-	53,002	53,002
29	35200	Wells \ Rights of Way	2,463,749	3.5	Storage (50/50)	-	1,231,874	1,231,874
30	35201	Well Construction	1,502,528	3.5	Storage (50/50)	-	751,264	751,264
31	35202	Well Equipment	474,361	3.5	Storage (50/50)	-	237,180	237,180
32	35203	Cushion Gas	702,999	3.5	Storage (50/50)	-	351,499	351,499
33	35210	Leaseholds	167,328	3.5	Storage (50/50)	-	83,664	83,664
34	35211	Storage Rights	44,691	3.5	Storage (50/50)	-	22,346	22,346
35	35301	Field Lines	105,566	3.5	Storage (50/50)	-	52,783	52,783
36	35302	Tributary Lines	153,747	3.5	Storage (50/50)	-	76,873	76,873
37	35400	Compressor Station Equipment	682,172	3.5	Storage (50/50)	-	341,086	341,086
38	35500	Meas & Reg. Equipment	167,060	3.5	Storage (50/50)	-	83,530	83,530
39	35600	Purification Equipment	322,628	3.5	Storage (50/50)	-	161,314	161,314
40								
41		Total Storage Plant	7,046,197			0	3,523,099	3,523,099
42								
43		Transmission:						
44								
45	36510	Land & Land Rights	-	2.0	Demand	-	-	-
46	36520	Rights of Way	587,414	2.0	Demand	-	587,414	-
47	36602	Structures & Improvements	29,122	2.0	Demand	-	29,122	-
48	36603	Other Structues	62,894	2.0	Demand	-	62,894	-
49	36700	Mains Cathodic Protection	33,163	2.0	Demand	-	33,163	-
50	36701	Mains - Steel	18,044,112	2.0	Demand	-	18,044,112	-
51	36703	Mains - Anodes	11,180	2.0	Demand	-	11,180	-
52	36900	Meas. & Reg. Equipment	620,559	2.0	Demand	-	620,559	-
53	36901	Meas. & Reg. Equipment	2,023,747	2.0	Demand	-	2,023,747	-
54								
55		Total Transmission Plant	21,412,190			0	21,412,190	0
56								
57		Distribution:						
58								
59	37400	Land & Land Rights	-	4.0	Mains (Peak and Average)	-	-	-
60	37401	Land	-	4.0	Mains (Peak and Average)	-	-	-
61	37402	Land Rights	644,160	4.0	Mains (Peak and Average)	-	397,580	246,580
62	37403	Land Other	-	4.0	Mains (Peak and Average)	-	-	-
63	37500	Structures & Improvements	136,375	4.0	Mains (Peak and Average)	-	84,171	52,203
64	37501	Structures & Improvements T.B.	81,770	4.0	Mains (Peak and Average)	-	50,469	31,301
65	37502	Land Rights	40,711	4.0	Mains (Peak and Average)	-	25,127	15,584
66	37503	Improvements	2,204	4.0	Mains (Peak and Average)	-	1,361	844
67	37600	Mains Cathodic Protection	1,792,334	4.0	Mains (Peak and Average)	-	1,106,241	686,093
68	37601	Mains - Steel	30,950,942	4.0	Mains (Peak and Average)	-	19,103,139	11,847,804
69	37602	Mains - Plastic	28,052,270	4.0	Mains (Peak and Average)	-	17,314,058	10,738,212
70	37603	Mains - Anodes	1,851,162	4.0	Mains (Peak and Average)	-	1,142,550	708,612
71	37604	Mains - Leak Clamps	5,615,083	4.0	Mains (Peak and Average)	-	3,465,668	2,149,414
72	37800	Meas & Reg. Sta. Equip - General	5,288,177	4.0	Mains (Peak and Average)	-	3,263,900	2,024,277
73	37900	Meas & Reg. Sta. Equip - City Gate	1,456,651	4.0	Mains (Peak and Average)	-	899,055	557,596
74	37905	Meas & Reg. Sta. Equipment T.b.	1,068,358	4.0	Mains (Peak and Average)	-	659,398	408,960
75	38000	Services	38,828,841	1.0	Customer	38,828,841	-	-
76	38100	Meters	23,998,006	1.0	Customer	23,998,006	-	-
77	38200	Meter Installaitons	22,719,274	1.0	Customer	22,719,274	-	-
78	38300	House Regulators	469,350	1.0	Customer	469,350	-	-
79	38400	House Reg. Installations	130,024	1.0	Customer	130,024	-	-
80	38500	Ind. Meas. & Reg. Sta. Equipment	3,090,645	1.0	Customer	3,090,645	-	-
81	38600	Other Prop. On Cust. Prem	-	99.0	-	-	-	-
82								
83		Total Distribution Plant	166,216,337			89,236,139	47,512,718	29,467,480
84								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
85		General:						
86								
87	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
88	39000	Structures & Improvements	1,968,463	5.4	P, S, T & D Plant	702,419	799,809	466,234
89	39002	Structures - Brick	118,817	5.4	P, S, T & D Plant	42,398	48,277	28,142
90	39003	Improvements	335,075	5.4	P, S, T & D Plant	119,567	136,145	79,363
91	39003	Air Conditioning Equipment	8,916	5.4	P, S, T & D Plant	3,181	3,622	2,112
92	39004	Improvement to Leased Premises	1,267,195	5.4	P, S, T & D Plant	452,181	514,876	300,138
93	39009	Office Furniture & Equipment	1,473,706	5.4	P, S, T & D Plant	525,872	598,784	349,050
94	39100	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
95	39102	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
96	39103	Transportation Equipment	75,817	5.4	P, S, T & D Plant	27,054	30,805	17,957
97	39200	Trucks	-	5.4	P, S, T & D Plant	-	-	-
98	39201	Trailers	8,658	5.4	P, S, T & D Plant	3,089	3,518	2,051
99	39202	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
100	39400	Tools, Shop & Garage Equipment	3,345,740	5.4	P, S, T & D Plant	1,193,882	1,359,413	792,445
101	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
102	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
103	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
104	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
105	39700	Communication Equipment	366,653	5.4	P, S, T & D Plant	130,835	148,975	86,843
106	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
107	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
108	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
109	39800	Miscellaneous Equipment	1,548,948	5.4	P, S, T & D Plant	552,721	629,355	366,871
110	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
111	39901	Other Tangible Property - Servers - H/W	21,595	5.4	P, S, T & D Plant	7,706	8,774	5,115
112	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
113	39903	Other Tangible Property - Network - H/W	-	5.4	P, S, T & D Plant	-	-	-
114	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
115	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
116	39906	Other Tang. Property - PC Hardware	530,003	5.4	P, S, T & D Plant	189,125	215,347	125,532
117	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
118	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
119	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
120		Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
121		Retirement Work in Progress	(1,655,581)	5.4	P, S, T & D Plant	(590,771)	(672,682)	(392,128)
122		AR 15 general plant amortization	-	5.4	P, S, T & D Plant	-	-	-
123								
124		Total General Plant	9,414,005			3,359,260	3,825,019	2,229,726
125								
126		TOTAL DIRECT RESERVE FOR DEPRECIATION	204,216,911			92,641,139	76,325,108	35,250,665
127								
128		Kentucky Mid-States General Office:						
129								
130		Intangible Plant:						
131								
132	30100	Organization	-	5.4	P, S, T & D Plant	-	-	-
133	30200	Franchises & Consents	-	5.4	P, S, T & D Plant	-	-	-
134	30300	Misc Intangible Plant	-	5.4	P, S, T & D Plant	-	-	-
135								
136		Total Intangible Plant:	-			0	0	0
137								
138		General:						
139								
140	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
141	39001	Structures Frame	60,032	5.4	P, S, T & D Plant	21,422	24,392	14,219
142	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
143	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
144	39004	Air Conditioning Equipment	7,666	5.4	P, S, T & D Plant	2,735	3,115	1,816
145	39009	Improvement to leased Premises	19,405	5.4	P, S, T & D Plant	6,925	7,885	4,596
146	39100	Office Furniture & Equipment	4,261	5.4	P, S, T & D Plant	1,520	1,731	1,009
147	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
148	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
149	39200	Transportation Equipment	(990)	5.4	P, S, T & D Plant	(353)	(402)	(235)
150	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
151	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
152	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
153	39400	Tools, Shop & Garage Equipment	26,914	5.4	P, S, T & D Plant	9,604	10,936	6,375
154	39600	Power Operated Equipment	1,496	5.4	P, S, T & D Plant	534	608	354
155	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
156	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
157	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
158	39700	Communication Equipment	(11,027)	5.4	P, S, T & D Plant	(3,935)	(4,480)	(2,612)
159	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
160	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
161	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
162	39800	Miscellaneous Equipment	(63,459)	5.4	P, S, T & D Plant	(22,645)	(25,784)	(15,030)
163	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
164	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
165	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
166	39903	Other Tangible Property - Network - H/W	9,760	5.4	P, S, T & D Plant	3,483	3,966	2,312
167	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
168	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
169	39906	Other Tang. Property - PC Hardware	-	5.4	P, S, T & D Plant	-	-	-
170	39907	Other Tang. Property - PC Software	21,748	5.4	P, S, T & D Plant	7,760	8,836	5,151
171	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
172	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
173	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
174		Retirement Work in Progress	26,243	5.4	P, S, T & D Plant	9,364	10,663	6,216
175								
176		Total General Plant	102,049			36,415	41,464	24,171
177								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF RESERVE FOR DEPRECIATION AND AMORTIZATION

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
178		Shared Services General Office:						
179								
180		General:						
181								
182	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
183	39000	Structures & Improvements	158,337	5.4	P, S, T & D Plant	56,501	64,334	37,503
184	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
185	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
186	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
187	39009	Improvement to leased Premises	496,454	5.4	P, S, T & D Plant	177,153	201,715	117,586
188	39100	Office Furniture & Equipment	193,036	5.4	P, S, T & D Plant	68,882	78,433	45,721
189	39102	Remittance Processing Equip	0	5.4	P, S, T & D Plant	0	0	0
190	39103	Office Machines	0	5.4	P, S, T & D Plant	0	0	0
191	39200	Transportation Equipment	10,393	5.4	P, S, T & D Plant	3,709	4,223	2,462
192	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
193	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
194	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
195	39400	Tools, Shop & Garage Equipment	1,267	5.4	P, S, T & D Plant	452	515	300
196	39500	39500-Laboratory Equipment	-	5.4	P, S, T & D Plant	-	-	-
197	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
198	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
199	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
200	39700	Communication Equipment	7,704	5.4	P, S, T & D Plant	2,749	3,130	1,825
201	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
202	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
203	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
204	39800	Miscellaneous Equipment	2,531	5.4	P, S, T & D Plant	903	1,028	599
205	39900	Other Tangible Property	(0)	5.4	P, S, T & D Plant	(0)	(0)	(0)
206	39901	Other Tangible Property - Servers - H/W	595,292	5.4	P, S, T & D Plant	212,422	241,874	140,996
207	39902	Other Tangible Property - Servers - S/W	703,290	5.4	P, S, T & D Plant	250,959	285,755	166,576
208	39903	Other Tangible Property - Network - H/W	95,736	5.4	P, S, T & D Plant	34,162	38,899	22,675
209	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
210	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
211	39906	Other Tang. Property - PC Hardware	86,835	5.4	P, S, T & D Plant	30,986	35,282	20,567
212	39907	Other Tang. Property - PC Software	3,178	5.4	P, S, T & D Plant	1,134	1,291	753
213	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
214	39909	Other Tang. Property - Application Software	4,933,686	5.4	P, S, T & D Plant	1,760,519	2,004,614	1,168,554
215	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
216	ADJ	WTW Adjustment	9,173	5.4	P, S, T & D Plant	3,273	3,727	2,173
217								
218		Total General Plant	7,296,912			2,603,804	2,964,819	1,728,289
219								
220		Shared Services Customer Support:						
221								
222		General:						
223								
224	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
225	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
226	36602	Structures & Improvements	420,763	5.4	P, S, T & D Plant	150,143	170,961	99,659
227	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
228	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
229	39009	Improvement to leased Premises	136,913	5.4	P, S, T & D Plant	48,855	55,629	32,428
230	39100	Office Furniture & Equipment	99,042	5.4	P, S, T & D Plant	35,342	40,242	23,458
231	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
232	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
233	39200	Transportation Equipment	2,251	5.4	P, S, T & D Plant	803	914	533
234	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
235	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
236	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
237	39400	Tools, Shop & Garage Equipment	10,609	5.4	P, S, T & D Plant	3,786	4,310	2,513
238	39500	Laboratory Equipment	4	5.4	P, S, T & D Plant	1	2	1
239	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
240	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
241	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
242	39700	Communication Equipment	98,184	5.4	P, S, T & D Plant	35,036	39,893	23,255
243	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
244	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
245	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
246	39800	Miscellaneous Equipment	10,096	5.4	P, S, T & D Plant	3,603	4,102	2,391
247	39900	Other Tangible Property	(8,317)	5.4	P, S, T & D Plant	(2,968)	(3,379)	(1,970)
248	39901	Other Tangible Property - Servers - H/W	208,015	5.4	P, S, T & D Plant	74,227	84,519	49,269
249	39902	Other Tangible Property - Servers - S/W	99,003	5.4	P, S, T & D Plant	35,328	40,226	23,449
250	39903	Other Tangible Property - Network - H/W	17,716	5.4	P, S, T & D Plant	6,322	7,198	4,196
251	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
252	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
253	39906	Other Tang. Property - PC Hardware	34,234	5.4	P, S, T & D Plant	12,216	13,909	8,108
254	39907	Other Tang. Property - PC Software	(3,876)	5.4	P, S, T & D Plant	(1,383)	(1,575)	(918)
255	39908	Other Tang. Property - Mainframe S/W	4,158,816	5.4	P, S, T & D Plant	1,484,017	1,689,775	985,024
256	39909	Other Tang. Property - Application Software	5,952	5.4	P, S, T & D Plant	2,124	2,418	1,410
257	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
258		Retirement Work in Progress	-	5.4	P, S, T & D Plant	-	-	-
259								
260		Total General Plant	5,289,404			1,887,452	2,149,146	1,252,806
261								
262		TOTAL RESERVE FOR DEPRECIATION	216,905,276			97,168,809	81,480,537	38,255,930

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF OTHER RATE BASE

		Test Year	Classif.	Classif.	Customer	Demand	Commodity
		$	Factor	Basis	$	$	$
1	Rate Base Additions:						
2							
3	Materials and Supplies - KY Direct	(29,510)	9.1	Allocated O&M Expenses	(1,810)	(3,782)	(23,918)
4	Materials and Supplies - KY Mid-States GO	549,932	9.1	Allocated O&M Expenses	33,722	70,483	445,727
5	Materials and Supplies - Shared Services GO	14,276	9.1	Allocated O&M Expenses	875	1,830	11,571
6	Materials and Supplies - Shared Services CS	0	9.1	Allocated O&M Expenses	-	-	-
7	Gas Storage Inventory	9,182,907	3.0	Commodity	-	-	9,182,907
8	Prepayments - KY Direct	0	9.1	Allocated O&M Expenses	-	-	-
9	Prepayments - KY Mid-States GO	0	9.1	Allocated O&M Expenses	-	-	-
10	Prepayments - Shared Services GO	0	9.1	Allocated O&M Expenses	-	-	-
11	Prepayments - Shared Services CS	0	9.1	Allocated O&M Expenses	-	-	-
12	Cash Working Capital	(2,199,566)	9.1	Allocated O&M Expenses	(134,880)	(281,910)	(1,782,776)
13	Regulatory Assets/Liabilities	(3,720,791)	9.1	Allocated O&M Expenses	(228,163)	(476,880)	(3,015,748)
14							
15	Total Rate Base Additions	3,797,249			(330,255)	(690,260)	4,817,764
16							
17							
18	Rate Base Deductions:						
19							
20	Customer Advances - KY Direct	(736,136)	1.0	Customer	(736,136)	-	-
21	Customer Advances - KY Mid-States GO	0	1.0	Customer	-	-	-
22	Customer Advances - Shared Services GO	0	1.0	Customer	-	-	-
23	Customer Advances - Shared Services CS	0	1.0	Customer	-	-	-
24	ADIT - KY Direct (Div 009)	(94,613,910)	5.7	Net Plant	(31,213,046)	(39,300,119)	(24,100,745)
25	ADIT - Shared Services GO (Div 002)	(7,615,553)	5.7	Net Plant	(2,512,364)	(3,163,300)	(1,939,889)
26	ADIT - Shared Services CS (Div 012)	(492,256)	5.7	Net Plant	(162,395)	(204,470)	(125,391)
27	ADIT - KY Mid-States GO (Div 091)	(184,730)	5.7	Net Plant	(60,942)	(76,732)	(47,056)
28	Change in Net Operating Loss Carryforward	(5,815,333)	5.7	Net Plant	(1,918,473)	(2,415,536)	(1,481,324)
29							
30	Total Rate Base Deductions	(109,457,919)			(36,603,357)	(45,160,157)	(27,694,405)
31							
32							
33	TOTAL OTHER RB	(105,660,670)			(36,933,611)	(45,850,417)	(22,876,641)
34							
35	Interest on Customer Deposits	0	1.0	Customer	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF O&M EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Production & Gathering:						
2		Operation						
3	7500	Op., Sup., & Eng.	0	99.0	-	-	-	-
4	7510	Production Maps & Records	0	99.0	-	-	-	-
5	7530	Field Lines Expenses	0	99.0	-	-	-	-
6	7540	Field Compressor Station Expense	0	99.0	-	-	-	-
7	7550	Field Compressor Sta. Fuel & Pwr.	0	99.0	-	-	-	-
8	7560	Field Meas. & Regul. Station Exp	0	99.0	-	-	-	-
9	7570	Purification Expense	0	99.0	-	-	-	-
10	7590	Other Expenses	0	99.0	-	-	-	-
11		Maintenance						
12	7610	Maint. Sup., & Eng.	0	99.0	-	-	-	-
13	7620	Structures and Improvements	0	99.0	-	-	-	-
14	7640	Field Line Maintenance	0	99.0	-	-	-	-
15	7650	Compressor Station Equip. Maint.	0	99.0	-	-	-	-
16	7660	Meas. & Regul. Station Equip Maint	0	99.0	-	-	-	-
17	7670	Purification Equipment Maintenance	0	99.0	-	-	-	-
18	7680	Other Equipment Maintenance	0	99.0	-	-	-	-
19	7690	Gas Processed By Others	0	99.0	-	-	-	-
20		Total Production & Gathering	0			0	0	0
21								
22		Other Gas Supply Expenses:						
23		Operation						
24	8001	Intercompany Gas Well-head Purchases	0	3.0	Commodity	-	-	-
25	8010	Natural gas field line purchases	115,617	3.0	Commodity	-	-	115,617
26	8040	Natural gas city gate purchases	50,226,537	3.0	Commodity	-	-	50,226,537
27	8050	Transmission-Operation supervision and engineering	(29,531)	3.0	Commodity	-	-	(29,531)
28	8051	Other Gas Purchases / Gas Cost Adjustments	53,391,020	3.0	Commodity	-	-	53,391,020
29	8052	PGA for Commercial	30,150,016	3.0	Commodity	-	-	30,150,016
30	8053	PGA for Industrial	4,872,096	3.0	Commodity	-	-	4,872,096
31	8054	PGA for Public Authority	4,999,866	3.0	Commodity	-	-	4,999,866
32	8058	Unbilled PGA Cost	(5,763,929)	3.0	Commodity	-	-	(5,763,929)
33	8059	PGA Offset to Unrecovered Gas Cost	(109,657,357)	3.0	Commodity	-	-	(109,657,357)
34	8060	Exchange gas	(122,035)	3.0	Commodity	-	-	(122,035)
35	8081	Gas withdrawn from storage-Debit	30,798,939	3.0	Commodity	-	-	30,798,939
36	8082	Gas delivered to storage-Credit	(14,414,625)	3.0	Commodity	-	-	(14,414,625)
37	8120	Gas used for other utility operations-Credit	(8,172)	3.0	Commodity	-	-	(8,172)
38	8580	Transmission and compression of gas by others	43,082,454	3.0	Commodity	-	-	43,082,454
39		Maintenance						
40	8350	Maint. Of Purch. Gas Meas. Sta.	0	3.0	Commodity	-	-	-
41		Total Other Gas Supply Expenses	87,640,898			0	0	87,640,898
42								
43		Underground Storage:						
44		Operation						
45	8140	Storage-Operation supervision and engineering	0	3.5	Storage (50/50)	-	-	-
46	8160	Wells expenses	35,164	3.5	Storage (50/50)	-	17,582	17,582
47	8170	Lines expenses	22,782	3.5	Storage (50/50)	-	11,391	11,391
48	8180	Compressor station expenses	44,776	3.5	Storage (50/50)	-	22,388	22,388
49	8190	Compressor station fuel and power	0	3.5	Storage (50/50)	-	-	-
50	8200	Storage-Measuring and regulating station expenses	9,536	3.5	Storage (50/50)	-	4,768	4,768
51	8210	Storage-Purification expenses	83,940	3.5	Storage (50/50)	-	41,970	41,970
52	8240	Storage-Other expenses	0	3.5	Storage (50/50)	-	-	-
53	8250	Storage well royalties	10,482	3.5	Storage (50/50)	-	5,241	5,241
54	8260	Rents	0	3.5	Storage (50/50)	-	-	-
55		Maintenance						
56	8300	Maint. Sup., & Eng.	0	3.5	Storage (50/50)	-	-	-
57	8310	Structures and Improvements	0	3.5	Storage (50/50)	-	-	-
58	8320	Reservoirs & Wells Maintenance	0	3.5	Storage (50/50)	-	-	-
59	8330	Line Maintenance	0	3.5	Storage (50/50)	-	-	-
60	8340	Compressor Station Equip Maint	46,416	3.5	Storage (50/50)	-	23,208	23,208
61	8350	Meas. & Regul. Station Equip Maint	0	3.5	Storage (50/50)	-	-	-
62	8360	Purification Equipment Maintenance	0	3.5	Storage (50/50)	-	-	-
63	8410	Other storage expenses-Operation labor and expenses	233,243	3.5	Storage (50/50)	-	116,621	116,621
64		Total Underground Storage Expense	486,338			0	243,169	243,169
65								
66		Transmission:						
67		Operation						
68	8500	Op., Sup., & Eng.	0	2.0	Demand	-	-	-
69	8510	System Control & Load Dispatching	0	2.0	Demand	-	-	-
70	8520	Communication Systems Expense	0	2.0	Demand	-	-	-
71	8530	Compressor Station Labor Expense	0	2.0	Demand	-	-	-
72	8540	Compressor Station Fuel Gas	0	2.0	Demand	-	-	-
73	8550	Compressor Station Fuel & Power	488	2.0	Demand	-	488	-
74	8560	Mains Expense	145,499	2.0	Demand	-	145,499	-
75	8570	Meas. & Regul. Station Expenses	11,936	2.0	Demand	-	11,936	-
76	8580	LDC Payment	0	2.0	Demand	-	-	-
77	8580	LDC Payment - A&G	0	2.0	Demand	-	-	-
78	8590	Other Expenses	0	2.0	Demand	-	-	-
79	8600	Rents	0	2.0	Demand	-	-	-
80		Maintenance						
81	8610	Maint. Sup., & Eng.	0	2.0	Demand	-	-	-
82	8620	Structures and Improvements	0	2.0	Demand	-	-	-
83	8630	Mains	22,915	2.0	Demand	-	22,915	-
84	8640	Compressor Station Equip Maint	0	2.0	Demand	-	-	-
85	8650	Meas. & Regul. Station Equip Maint	0	2.0	Demand	-	-	-
86	8660	Communication Equipment Maintenance	0	2.0	Demand	-	-	-
87	8670	Other Equipment Maintenance	0	2.0	Demand	-	-	-
88		Total Transmission Expense	180,838			0	180,838	0
89								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF O&M EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
90		Distribution:						
91		Operation						
92	8700	Supervision and Engineering	2,140,705	10.0	Composite of Accts. 871-879 & 886-893	211,070	1,153,074	776,562
93	8710	Distribution Load Dispatching	(41)	3.0	Commodity	-	-	(41)
94	8711	Odorization	132,819	3.0	Commodity	-	-	132,819
94	8720	Compressor Station Labor & Expenses	0	3.0	Commodity	-	-	-
95	8740	Mains & Services	6,802,984	12.0	Composite of Accts. 374-379	-	4,198,850	2,604,135
96	8750	Measuring and Regulating Station Exp. - Gen	1,361,535	12.0	Composite of Accts. 374-379	-	840,349	521,186
97	8760	Measuring and Regulating Station Exp. - Ind.	523	1.0	Customer	523	-	-
98	8770	Measuring and Regulating Sta. Exp. - City Gate	5,487	12.0	Composite of Accts. 374-379	-	3,387	2,100
99	8780	Meters and House Regulator Expense	938,471	1.0	Customer	938,471	-	-
100	8790	Customer Installations Expense	257	1.0	Customer	257	-	-
101	8800	Other Expense	3,085	10.0	Composite of Accts. 871-879 & 886-893	304	1,662	1,119
102	8810	Rents	75,023	10.0	Composite of Accts. 871-879 & 886-893	7,397	40,410	27,215
103		Maintenance						
104	8850	Maintenance Supervision and Engineering	0	10.0	Composite of Accts. 871-879 & 886-893	-	-	-
105	8860	Maintenance of Structures and Improvements	0	12.0	Composite of Accts. 374-379	-	-	-
106	8870	Maintenance of Mains	144,480	12.0	Composite of Accts. 374-379	-	89,174	55,306
107	8890	Maintenance of compressor station equipment	140,590	3.0	Commodity	-	-	140,590
108	8900	Maint. of Measuring and Regulating Station Equip. - General	0	12.0	Composite of Accts. 374-379	-	-	-
109	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	135	1.0	Customer	135	-	-
110	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	178	12.0	Composite of Accts. 374-379	-	110	68
111	8930	Maintenance of Services	0	1.0	Customer	-	-	-
112	8940	Maintenance of Meters and House Regulators	0	1.0	Customer	-	-	-
113	8950	Maintenance of Other Equipment	0	10.0	Composite of Accts. 871-879 & 886-893	-	-	-
114		Total Distribution	11,746,231			1,158,157	6,327,016	4,261,059
115								
116		Customer Accounts:						
117	9010	Supervision	0	1.0	Customer	-	-	-
118	9020	Meter Reading Expense	735,288	1.0	Customer	735,288	-	-
119	9030	Customer Records and Collection Expenses	1,067,803	1.0	Customer	1,067,803	-	-
120	9040	Uncollectible Accounts	731,532	1.0	Customer	731,532	-	-
121	9050	Miscellaneous Customer Accounts Expenses	0	1.0	Customer	-	-	-
122		Total Customer Accounts	2,534,624			2,534,624	0	0
123								
124		Customer Service and Information:						
125	9070	Supervision	0	1.0	Customer	-	-	-
126	9080	Customer Assistance Expenses	0	1.0	Customer	-	-	-
127	9090	Informational and Instructional Advertising Expenses	214,461	1.0	Customer	214,461	-	-
128	9100	Miscellaneous Customer Service and Informational Expenses	0	1.0	Customer	-	-	-
129		Total Customer Service and Information	214,461			214,461	0	0
130								
131		Sales:						
132	9110	Supervision	158,549	1.0	Customer	158,549	-	-
133	9120	Demonstrating and Selling Expenses	77,078	1.0	Customer	77,078	-	-
134	9130	Advertising Expenses	36,821	1.0	Customer	36,821	-	-
135	9160	Miscellaneous Sales Expenses	(188,721)	1.0	Customer	(188,721)	-	-
136		Total Sales	83,728			83,728	0	0
137								
138		Administrative & General:						
139		Operation						
140	9200	Administrative and General Salaries	-	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	-	-	-
141	9210	Office Supplies and Expenses	69,069	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	12,576	33,758	22,735
142	9220	Administrative Expenses Transferred - Customer Support	-	1.0	Customer	-	-	-
143	9220	Administrative Expenses Transferred - General	18,251,309	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	3,323,172	8,920,466	6,007,671
144	9230	Outside Services Employed	69,993	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	12,744	34,209	23,039
145	9240	Property Insurance	-	5.7	Net Plant	-	-	-
146	9250	Injuries and Damages	23,257	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	4,235	11,367	7,655
147	9260	Employee Pensions and Benefits	872,759	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	158,911	426,567	287,281
148	9270	Franchise Requirements	635	1.0	Customer	635	-	-
149	9280	Regulatory Commission Expenses	165,392	1.0	Customer	165,392	-	-
150	930.1	General Advertising Expenses	-	1.0	Customer	-	-	-
151	930.2	Miscellaneous General Expense	24,411	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	4,445	11,931	8,035
152	ADJ	Adjustments	(1,404,321)	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	(255,697)	(686,372)	(462,252)
153		Maintenance						
154	9320	Maintenance of General Plant	0	17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	-	-	-
155		Total A&G	18,072,504			3,426,413	8,751,926	5,894,165
156								
157		TOTAL O&M EXPENSE	120,959,622			7,417,382	15,502,949	98,039,291

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
1		Intangible Plant:						
2								
3	30100	Organization	-	99.0	-	-	-	-
4	30200	Franchises & Consents	-	99.0	-	-	-	-
5	30300	Misc Intangible Plant	-	99.0	-	-	-	-
6								
7		Total Intangible Plant:	0			0	0	0
8								
9		Production Plant:						
10								
11	32520	Producing Leaseholds	-	99.0	-	-	-	-
12	32540	Rights of Ways	-	99.0	-	-	-	-
13	33100	Production Gas Wells Equipment	-	99.0	-	-	-	-
14	33201	Field Lines	-	99.0	-	-	-	-
15	33202	Tributary Lines	-	99.0	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	-	99.0	-	-	-	-
17	33600	Purification Equipment	-	99.0	-	-	-	-
18								
19		Total Production Plant	0			0	0	0
20								
21		Storage Plant:						
22								
23	35010	Land	-	3.5	Storage (50/50)	-	-	-
24	35020	Rights of Way	32	3.5	Storage (50/50)	-	16	16
25	35100	Structures and Improvements	294	3.5	Storage (50/50)	-	147	147
26	35102	Compression Station Equipment	3,062	3.5	Storage (50/50)	-	1,531	1,531
27	35103	Meas. & Reg. Sta. Structues	255	3.5	Storage (50/50)	-	127	127
28	35104	Other Structures	1,897	3.5	Storage (50/50)	-	948	948
29	35200	Wells \ Rights of Way	241,977	3.5	Storage (50/50)	-	120,988	120,988
30	35201	Well Construction	27,200	3.5	Storage (50/50)	-	13,600	13,600
31	35202	Well Equipment	9,210	3.5	Storage (50/50)	-	4,605	4,605
32	35203	Cushion Gas	23,728	3.5	Storage (50/50)	-	11,864	11,864
33	35210	Leaseholds	1,000	3.5	Storage (50/50)	-	500	500
34	35211	Storage Rights	557	3.5	Storage (50/50)	-	279	279
35	35301	Field Lines	2,209	3.5	Storage (50/50)	-	1,105	1,105
36	35302	Tributary Lines	2,637	3.5	Storage (50/50)	-	1,319	1,319
37	35400	Compressor Station Equipment	308,927	3.5	Storage (50/50)	-	154,463	154,463
38	35500	Meas & Reg. Equipment	5,107	3.5	Storage (50/50)	-	2,553	2,553
39	35600	Purification Equipment	33,187	3.5	Storage (50/50)	-	16,594	16,594
40								
41		Total Storage Plant	661,278			0	330,639	330,639
42								
43		Transmission:						
44								
45	36510	Land & Land Rights	-	2.0	Demand	-	-	-
46	36520	Rights of Way	7,376	2.0	Demand	-	7,376	-
47	36602	Structures & Improvements	4,496	2.0	Demand	-	4,496	-
48	36603	Other Structues	-	2.0	Demand	-	-	-
49	36700	Mains Cathodic Protection	1,478	2.0	Demand	-	1,478	-
50	36701	Mains - Steel	384,012	2.0	Demand	-	384,012	-
51	36703	Mains - Anodes	-	2.0	Demand	-	-	-
52	36900	Meas. & Reg. Equipment	35,793	2.0	Demand	-	35,793	-
53	36901	Meas. & Reg. Equipment	40,624	2.0	Demand	-	40,624	-
54								
55		Total Transmission Plant	473,778			0	473,778	0
56								
57		Distribution:						
58								
59	37400	Land & Land Rights	-	4.0	Mains (Peak and Average)	-	-	-
60	37401	Land	-	4.0	Mains (Peak and Average)	-	-	-
61	37402	Land Rights	54,464	4.0	Mains (Peak and Average)	-	33,615	20,848
62	37403	Land Other	-	4.0	Mains (Peak and Average)	-	-	-
63	37500	Structures & Improvements	4,841	4.0	Mains (Peak and Average)	-	2,988	1,853
64	37501	Structures & Improvements T.B.	1,437	4.0	Mains (Peak and Average)	-	887	550
65	37502	Land Rights	666	4.0	Mains (Peak and Average)	-	411	255
66	37503	Improvements	58	4.0	Mains (Peak and Average)	-	36	22
67	37600	Mains Cathodic Protection	159,292	4.0	Mains (Peak and Average)	-	98,316	60,976
68	37601	Mains - Steel	3,554,207	4.0	Mains (Peak and Average)	-	2,193,681	1,360,525
69	37602	Mains - Plastic	3,416,357	4.0	Mains (Peak and Average)	-	2,108,600	1,307,758
70	37603	Mains - Anodes	200,720	4.0	Mains (Peak and Average)	-	123,886	76,834
71	37604	Mains - Leak Clamps	339,494	4.0	Mains (Peak and Average)	-	209,538	129,956
72	37800	Meas & Reg. Sta. Equip - General	573,607	4.0	Mains (Peak and Average)	-	354,035	219,573
73	37900	Meas & Reg. Sta. Equip - City Gate	214,735	4.0	Mains (Peak and Average)	-	132,536	82,199
74	37905	Meas & Reg. Sta. Equipment T.b.	37,287	4.0	Mains (Peak and Average)	-	23,014	14,273
75	38000	Services	4,814,131	1.0	Customer	4,814,131	-	-
76	38100	Meters	2,722,922	1.0	Customer	2,722,922	-	-
77	38200	Meter Installaitons	2,026,363	1.0	Customer	2,026,363	-	-
78	38300	House Regulators	124,799	1.0	Customer	124,799	-	-
79	38400	House Reg. Installations	12,401	1.0	Customer	12,401	-	-
80	38500	Ind. Meas. & Reg. Sta. Equipment	97,340	1.0	Customer	97,340	-	-
81	38600	Other Prop. On Cust. Prem	-	99.0	-	-	-	-
82								
83		Total Distribution Plant	18,355,122			9,797,957	5,281,542	3,275,623
84								

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
85		General:						
86								
87	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
88	39000	Structures & Improvements	225,186	5.4	P, S, T & D Plant	80,355	91,496	53,336
89	39001	Structures - Brick	4,207	5.4	P, S, T & D Plant	1,501	1,709	996
90	39002	Improvements	21,302	5.4	P, S, T & D Plant	7,601	8,655	5,045
91	39003	Air Conditioning Equipment	553	5.4	P, S, T & D Plant	197	225	131
92	39004	Improvement to leased Premises	-	5.4	P, S, T & D Plant	-	-	-
93	39009	Office Furniture & Equipment	90,847	5.4	P, S, T & D Plant	32,417	36,912	21,517
94	39100	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
95	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
96	39200	Transportation Equipment	2,511	5.4	P, S, T & D Plant	896	1,020	595
97	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
98	39202	Trailers	508	5.4	P, S, T & D Plant	181	207	120
99	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
100	39400	Tools, Shop & Garage Equipment	169,362	5.4	P, S, T & D Plant	60,435	68,814	40,114
101	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
102	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
103	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
104	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
105	39700	Communication Equipment	28,944	5.4	P, S, T & D Plant	10,328	11,760	6,855
106	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
107	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
108	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
109	39800	Miscellaneous Equipment	199,380	5.4	P, S, T & D Plant	71,146	81,010	47,224
110	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
111	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
112	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
113	39903	Other Tangible Property - Network - H/W	-	5.4	P, S, T & D Plant	-	-	-
114	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
115	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
116	39906	Other Tang. Property - PC Hardware	11,055	5.4	P, S, T & D Plant	3,945	4,492	2,619
117	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
118	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
119	39908	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
120	40600	Amortization of gas plant acquisition adjustments	49,305	5.4	P, S, T & D Plant	17,594	20,033	11,678
121								
122								
123		Total General Plant	803,161			286,597	326,334	190,230
124								
125		TOTAL DIRECT DEPRECIATION EXPENSE	20,293,339			10,084,554	6,412,293	3,796,492
126								
127		Kentucky Mid-States General Office:						
128								
129		Intangible Plant:						
130								
131	30100	Organization	-	5.4	P, S, T & D Plant	-	-	-
132	30200	Franchises & Consents	-	5.4	P, S, T & D Plant	-	-	-
133	30300	Misc Intangible Plant	-	5.4	P, S, T & D Plant	-	-	-
134								
135		Total Intangible Plant:	0			0	0	0
136								
137		General:						
138								
139	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
140	39001	Structures Frame	3,943	5.4	P, S, T & D Plant	1,407	1,602	934
141	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
142	38900	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
143	39004	Air Conditioning Equipment	156	5.4	P, S, T & D Plant	56	63	37
144	39009	Improvement to leased Premises	-	5.4	P, S, T & D Plant	-	-	-
145	39100	Office Furniture & Equipment	865	5.4	P, S, T & D Plant	309	352	205
146	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
147	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
148	39200	Transportation Equipment	62	5.4	P, S, T & D Plant	22	25	15
149	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
150	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
151	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
152	39400	Tools, Shop & Garage Equipment	1,400	5.4	P, S, T & D Plant	500	569	332
153	39600	Power Operated Equipment	10	5.4	P, S, T & D Plant	4	4	2
154	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
155	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
156	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
157	39700	Communication Equipment	-	5.4	P, S, T & D Plant	-	-	-
158	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
159	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
160	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
161	39800	Miscellaneous Equipment	-	5.4	P, S, T & D Plant	-	-	-
162	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
163	39901	Other Tangible Property - Servers - H/W	-	5.4	P, S, T & D Plant	-	-	-
164	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
165	39903	Other Tangible Property - Network - H/W	1,552	5.4	P, S, T & D Plant	554	631	368
166	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
167	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
168	39906	Other Tang. Property - PC Hardware	-	5.4	P, S, T & D Plant	-	-	-
169	39907	Other Tang. Property - PC Software	-	5.4	P, S, T & D Plant	-	-	-
170	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
171	39909	Other Tang. Property - Application Software	-	5.4	P, S, T & D Plant	-	-	-
172	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
173								
174								
175		Total General Plant	7,989			2,851	3,246	1,892

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Test Year $	Classif. Factor	Classif. Basis	Customer $	Demand $	Commodity $
176								
177		Shared Services General Office:						
178								
179		General:						
180								
181	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
182	39000	Structures & Improvements	11,489	5.4	P, S, T & D Plant	4,100	4,668	2,721
183	36602	Structures & Improvements	-	5.4	P, S, T & D Plant	-	-	-
184	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
185	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
186	39009	Improvement to leased Premises	28,706	5.4	P, S, T & D Plant	10,243	11,664	6,799
187	39100	Office Furniture & Equipment	24,600	5.4	P, S, T & D Plant	8,778	9,995	5,827
188	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
189	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
190	39200	Transportation Equipment	948	5.4	P, S, T & D Plant	338	385	225
191	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
192	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
193	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
194	39400	Tools, Shop & Garage Equipment	171	5.4	P, S, T & D Plant	61	69	41
195	39500	Laboratory Equipment	-	5.4	P, S, T & D Plant	-	-	-
196	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
197	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
198	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
199	39700	Communication Equipment	2,242	5.4	P, S, T & D Plant	800	911	531
200	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
201	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
202	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
203	39800	Miscellaneous Equipment	386	5.4	P, S, T & D Plant	138	157	91
204	39900	Other Tangible Property	-	5.4	P, S, T & D Plant	-	-	-
205	39901	Other Tangible Property - Servers - H/W	336,969	5.4	P, S, T & D Plant	120,243	136,915	79,812
206	39902	Other Tangible Property - Servers - S/W	221,166	5.4	P, S, T & D Plant	78,920	89,862	52,384
207	39903	Other Tangible Property - Network - H/W	33,165	5.4	P, S, T & D Plant	11,835	13,475	7,855
208	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
209	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
210	39906	Other Tang. Property - PC Hardware	42,815	5.4	P, S, T & D Plant	15,278	17,396	10,141
211	39907	Other Tang. Property - PC Software	440	5.4	P, S, T & D Plant	157	179	104
212	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
213	39909	Other Tang. Property - Application Software	510,816	5.4	P, S, T & D Plant	182,278	207,550	120,988
214	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
215	ADJ	WTW Adjustment	(8,467)	5.4	P, S, T & D Plant	(3,021)	(3,440)	(2,005)
216								
217		Total General Plant	1,205,447			430,147	489,787	285,513
218								
219		Shared Services Customer Support:						
220								
221		General:						
222								
223	37400	Land & Land Rights	-	5.4	P, S, T & D Plant	-	-	-
224	39001	Structures Frame	-	5.4	P, S, T & D Plant	-	-	-
225	36602	Structures & Improvements	26,371	5.4	P, S, T & D Plant	9,410	10,715	6,246
226	37503	Improvements	-	5.4	P, S, T & D Plant	-	-	-
227	39004	Air Conditioning Equipment	-	5.4	P, S, T & D Plant	-	-	-
228	39009	Improvement to leased Premises	7,572	5.4	P, S, T & D Plant	2,702	3,077	1,794
229	39100	Office Furniture & Equipment	11,237	5.4	P, S, T & D Plant	4,010	4,566	2,662
230	39102	Remittance Processing Equip	-	5.4	P, S, T & D Plant	-	-	-
231	39103	Office Machines	-	5.4	P, S, T & D Plant	-	-	-
232	39200	Transportation Equipment	-	5.4	P, S, T & D Plant	-	-	-
233	39201	Trucks	-	5.4	P, S, T & D Plant	-	-	-
234	39202	Trailers	-	5.4	P, S, T & D Plant	-	-	-
235	39300	Stores Equipment	-	5.4	P, S, T & D Plant	-	-	-
236	39500	Laboratory Equipment	2,649	5.4	P, S, T & D Plant	945	1,076	627
237	39600	Power Operated Equipment	-	5.4	P, S, T & D Plant	-	-	-
238	39603	Ditchers	-	5.4	P, S, T & D Plant	-	-	-
239	39604	Backhoes	-	5.4	P, S, T & D Plant	-	-	-
240	39605	Welders	-	5.4	P, S, T & D Plant	-	-	-
241	39700	Communication Equipment	6,715	5.4	P, S, T & D Plant	2,396	2,728	1,590
242	39701	Communication Equipment - Mobile Radios	-	5.4	P, S, T & D Plant	-	-	-
243	39702	Communication Equipment - Fixed Radios	-	5.4	P, S, T & D Plant	-	-	-
244	39705	Communication Equip. - Telemetering	-	5.4	P, S, T & D Plant	-	-	-
245	39800	Miscellaneous Equipment	2,101	5.4	P, S, T & D Plant	750	854	498
246	39900	Other Tangible Property	1,186	5.4	P, S, T & D Plant	423	482	281
247	39901	Other Tangible Property - Servers - H/W	38,567	5.4	P, S, T & D Plant	13,762	15,670	9,135
248	39902	Other Tangible Property - Servers - S/W	-	5.4	P, S, T & D Plant	-	-	-
249	39903	Other Tangible Property - Network - H/W	4,009	5.4	P, S, T & D Plant	1,431	1,629	950
250	39904	Other Tang. Property - CPU	-	5.4	P, S, T & D Plant	-	-	-
251	39905	Other Tangible Property - MF - Hardware	-	5.4	P, S, T & D Plant	-	-	-
252	39906	Other Tang. Property - PC Hardware	18,676	5.4	P, S, T & D Plant	6,664	7,588	4,423
253	39907	Other Tang. Property - PC Software	11	5.4	P, S, T & D Plant	4	5	3
254	39908	Other Tang. Property - Mainframe S/W	-	5.4	P, S, T & D Plant	-	-	-
255	39909	Other Tang. Property - Application Software	402,314	5.4	P, S, T & D Plant	143,560	163,465	95,289
256	39924	Other Tang. Property - General Startup Costs	-	5.4	P, S, T & D Plant	-	-	-
257								
258								
259		Total General Plant	521,409			186,058	211,854	123,497
260								
261	NTB	To Match Schedule C-1	192.03	5.4	P, S, T & D Plant	69	78	45
262								
263		TOTAL DEPRECIATION EXPENSE	22,028,375			10,703,678	7,117,258	4,207,439

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

		Test Year	Classif.	Classif.	Customer	Demand	Commodity
		$	Factor	Basis	$	$	$
1	Taxes Other Than Income						
2							
3	Non Revenue Related:						
4	Payroll Related	375,952	9.1	Allocated O&M Expenses	23,054	48,184	304,714
5	Property Related	12,386,174	5.4	P, S, T & D Plant	4,419,838	5,032,645	2,933,691
6	DOT Transmission User Tax	232,790	9.1	Allocated O&M Expenses	14,275	29,836	188,679
7	Other	444,432	9.1	Allocated O&M Expenses	27,253	56,961	360,218
8	Total Non Revenue Related:	13,439,348			4,484,419	5,167,627	3,787,302
9							
10	Revenue Related:						
11	State Gross Receipts - Tax	0	99.0	-	-	-	-
12	Local Gross Receipts - Tax	0	99.0	-	-	-	-
13	Public Service Commission Assessment	291,875	3.0	Commodity	-	-	291,875
14	Total Revenue Related:	291,875			0	0	291,875
15							
16	Total Taxes, Other Than Income	13,731,224			4,484,419	5,167,627	4,079,177
17							
18							
19	Interest Expense	10,240,350	13.0	Rate Base	3,344,439	4,221,594	2,674,317
20							
21	Amortization of COS and Depreciation Reserves	(2,188,517)	18.0	Total Cost of Service at Equalized ROR	(434,546)	(541,196)	(1,212,775)
22							
23	Amortization of Excess ADIT	(189,998)	18.0	Total Cost of Service at Equalized ROR	(37,725)	(46,984)	(105,288)

Atmos Energy Corporation, Kentucky/Mid-States Division						
Class Cost of Service - Energy/Demand Study						
Forecasted Test Period: Twelve Months Ended March 31, 2026						
SUMMARY OF CLASSIFICATION						
	Test Year	Classif.	Classif.	Customer	Demand	Commodity
	$	Factor	Basis	$	$	$
Operating Revenues	187,822,013			32,763,472	40,609,989	114,448,552
Operating Expenses:						
Operating & Maintenance	120,959,622			7,417,382	15,502,949	98,039,291
Depreciation & Amortization	22,028,375			10,703,678	7,117,258	4,207,439
Taxes Other Than Income	13,731,224			4,484,419	5,167,627	4,079,177
Total Operating Expenses	156,719,221			22,605,479	27,787,834	106,325,907
Income Before Taxes	31,102,792			10,157,992	12,822,155	8,122,645
Interest Expense	10,240,350			3,344,439	4,221,594	2,674,317
Income Taxes:						
State Income Taxes	1,043,122	5.00%		340,678	430,028	272,416
Federal Income Taxes	4,162,057	21.00%		1,359,304	1,715,812	1,086,941
Total Deferred Income Taxes	0			0	0	0
Amortization of ITC	0			0	0	0
Total Income Taxes	5,205,179			1,699,981	2,145,840	1,359,358
Net Income	25,897,613			8,458,011	10,676,315	6,763,288
Total Rate Base	628,233,491			205,177,426	258,989,835	164,066,229
Rate of Return	4.1223%			4.1223%	4.1223%	4.1223%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Intangible Plant:								
2										
3	30100	Organization	6.2	P, S, T & D Plant - Customer	2,972	2,376	572	1	15	9
4	30200	Franchises & Consents	6.2	P, S, T & D Plant - Customer	42,768	34,182	8,230	16	212	128
5	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
6										
7		Total Intangible Plant:			45,740	36,558	8,802	17	227	137
8										
9		Production Plant:								
10										
11	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
12	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
13	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
14	33201	Field Lines	99.0	-	0	-	-	-	-	-
15	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
17	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
18										
19		Total Production Plant			0	0	0	0	0	0
20										
21		Storage Plant:								
22										
23	35010	Land	99.0	-	0	-	-	-	-	-
24	35020	Rights of Way	99.0	-	0	-	-	-	-	-
25	35100	Structures and Improvements	99.0	-	0	-	-	-	-	-
26	35102	Compression Station Equipment	99.0	-	0	-	-	-	-	-
27	35103	Meas. & Reg. Sta. Structues	99.0	-	0	-	-	-	-	-
28	35104	Other Structures	99.0	-	0	-	-	-	-	-
29	35200	Wells \ Rights of Way	99.0	-	0	-	-	-	-	-
30	35201	Well Construction	99.0	-	0	-	-	-	-	-
31	35202	Well Equipment	99.0	-	0	-	-	-	-	-
32	35203	Cushion Gas	99.0	-	0	-	-	-	-	-
33	35210	Leaseholds	99.0	-	0	-	-	-	-	-
34	35211	Storage Rights	99.0	-	0	-	-	-	-	-
35	35301	Field Lines	99.0	-	0	-	-	-	-	-
36	35302	Tributary Lines	99.0	-	0	-	-	-	-	-
37	35400	Compressor Station Equipment	99.0	-	0	-	-	-	-	-
38	35500	Meas & Reg. Equipment	99.0	-	0	-	-	-	-	-
39	35600	Purification Equipment	99.0	-	0	-	-	-	-	-
40										
41		Total Storage Plant			0	0	0	0	0	0
42										
43		Transmission:								
44										
45	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
46	36520	Rights of Way	99.0	-	0	-	-	-	-	-
47	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
48	36603	Other Structues	99.0	-	0	-	-	-	-	-
49	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
50	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
51	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
52	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
53	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
54										
55		Total Transmission Plant			0	0	0	0	0	0
56										
57		Distribution:								
58										
59	37400	Land & Land Rights	2.0	Bills	0	-	-	-	-	-
60	37401	Land	2.0	Bills	0	-	-	-	-	-
61	37402	Land Rights	2.0	Bills	0	-	-	-	-	-
62	37403	Land Other	2.0	Bills	0	-	-	-	-	-
63	37500	Structures & Improvements	2.0	Bills	0	-	-	-	-	-
64	37501	Structures & Improvements T.B.	2.0	Bills	0	-	-	-	-	-
65	37502	Land Rights	2.0	Bills	0	-	-	-	-	-
66	37503	Improvements	2.0	Bills	0	-	-	-	-	-
67	37600	Mains Cathodic Protection	2.0	Bills	0	-	-	-	-	-
68	37601	Mains - Steel	2.0	Bills	0	-	-	-	-	-
69	37602	Mains - Plastic	2.0	Bills	0	-	-	-	-	-
70	37603	Mains - Anodes	2.0	Bills	0	-	-	-	-	-
71	37604	Mains - Leak Clamps	2.0	Bills	0	-	-	-	-	-
72	37800	Meas & Reg. Sta. Equip - General	2.0	Bills	0	-	-	-	-	-
73	37900	Meas & Reg. Sta. Equip - City Gate	2.0	Bills	0	-	-	-	-	-
74	37905	Meas & Reg. Sta. Equipment T.b.	2.0	Bills	0	-	-	-	-	-
75	38000	Services	2.0	Bills	193,916,542	172,131,494	21,572,990	9,386	126,507	76,164
76	38100	Meters	4.0	Meter Investment	55,920,540	38,934,861	15,880,938	48,900	659,055	396,787
77	38200	Meter Installaitons	4.0	Meter Investment	61,761,518	43,001,661	17,539,724	54,007	727,894	438,232
78	38300	House Regulators	4.0	Meter Investment	3,974,497	2,767,256	1,128,722	3,476	46,842	28,201
79	38400	House Reg. Installations	4.0	Meter Investment	378,094	263,249	107,375	331	4,456	2,683
80	38500	Ind. Meas. & Reg. Sta. Equipment	2.2	Non-Residential Bills	5,725,878	-	5,670,142	2,467	33,251	20,019
81	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
82										
83		Total Distribution Plant			321,677,069	257,098,521	61,899,891	118,567	1,598,004	962,086

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
84										
85		General:								
86										
87	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	432,378	345,575	83,202	159	2,148	1,293
88	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	3,303,222	2,640,081	635,635	1,218	16,410	9,879
89	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
90	39002	Structures-Brick	6.2	P, S, T & D Plant - Customer	61,774	49,372	11,887	23	307	185
91	39003	Improvements	6.2	P, S, T & D Plant - Customer	312,815	250,016	60,195	115	1,554	936
92	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	4,623	3,695	890	2	23	14
93	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	452,181	361,403	87,013	167	2,246	1,352
94	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	648,350	518,190	124,761	239	3,221	1,939
95	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
96	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
97	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	64,498	51,550	12,411	24	320	193
98	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
99	39202	Trailers	6.2	P, S, T & D Plant - Customer	13,056	10,435	2,512	5	65	39
100	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
101	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	2,549,018	2,037,287	490,504	940	12,663	7,624
102	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
103	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
104	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
105	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
106	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	154,845	123,759	29,797	57	769	463
107	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
108	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
109	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
110	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	1,064,412	850,725	204,823	392	5,288	3,183
111	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
112	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	7,645	6,110	1,471	3	38	23
113	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
114	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
115	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
116	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
117	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	189,359	151,344	36,438	70	941	566
118	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
119	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
120	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
121	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
122										
123		Total General Plant			9,258,175	7,399,542	1,781,538	3,412	45,992	27,690
124										
125		TOTAL DIRECT PLANT			330,980,984	264,534,621	63,690,231	121,996	1,644,223	989,912
126										
127		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
128										
129		Kentucky Mid-States General Office:								
130										
131		Intangible Plant:								
132										
133	30100	Organization	6.2	P, S, T & D Plant - Customer	33,043	26,409	6,358	12	164	99
134	30200	Franchises & Consents	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
135	30300	Misc Intangible Plant	6.2	P, S, T & D Plant - Customer	197,845	158,127	38,071	73	983	592
136										
137		Total Intangible Plant			230,888	184,536	44,429	85	1,147	691
138										
139		General:								
140										
141	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
142	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	31,978	25,558	6,153	12	159	96
143	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
144	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
145	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	2,743	2,192	528	1	14	8
146	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	6,925	5,534	1,332	3	34	21
147	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	4,802	3,838	924	2	24	14
148	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
149	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
150	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	733	586	141	0	4	2
151	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
152	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
153	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
154	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	19,655	15,709	3,782	7	98	59
155	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	1,690	1,351	325	1	8	5
156	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
157	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
158	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
159	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
160	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
161	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
162	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
163	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
164	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
165	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
166	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
167	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	5,040	4,028	970	2	25	15
168	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
169	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
170	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
171	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	7,760	6,202	1,493	3	39	23
172	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
173	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
174	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
175										
176		Total General Plant			81,326	64,999	15,649	30	404	243
177										
178		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
179										
180		Shared Services General Office:								
181										
182		General:								
183										
184	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
185	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
186	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	172,431	137,814	33,181	64	857	516
187	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
188	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
189	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	229,223	183,205	44,109	84	1,139	686
190	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	137,088	109,567	26,380	51	681	410
191	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
192	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
193	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	5,135	4,104	988	2	26	15
194	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
195	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
196	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
197	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	491	392	94	0	2	1
198	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
199	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
200	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
201	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
202	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	12,561	10,039	2,417	5	62	38
203	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
204	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
205	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
206	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	1,968	1,573	379	1	10	6
207	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
208	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	937,862	749,581	180,472	346	4,659	2,805
209	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	754,796	603,266	145,244	278	3,750	2,257
210	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	104,214	83,293	20,054	38	518	312
211	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
212	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
213	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	76,668	61,277	14,753	28	381	229
214	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	1,347	1,076	259	0	7	4
215	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	1,762,881	1,408,973	339,229	650	8,758	5,273
216	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	590,509	471,961	113,631	218	2,933	1,766
217	39931	Other Tang. Property - ALGN	6.2	P, S, T & D Plant - Customer	285,233	227,971	54,887	105	1,417	853
218										
219		Total General Plant			5,072,408	4,054,092	976,077	1,870	25,198	15,171
220										
221		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
222										
223		Shared Services Customer Support:								
224										
225		General:								
226										
227	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	75,374	60,242	14,504	28	374	225
228	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
229	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	395,357	315,987	76,078	146	1,964	1,182
230	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
231	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
232	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	60,995	48,750	11,737	22	303	182
233	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	62,952	50,314	12,114	23	313	188
234	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
235	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
236	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	798	638	154	0	4	2
237	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
238	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
239	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
240	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	7,586	6,063	1,460	3	38	23
241	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
242	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
243	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
244	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
245	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	37,792	30,205	7,272	14	188	113
246	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
247	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
248	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
249	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	10,649	8,511	2,049	4	53	32
250	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	2,938	2,348	565	1	15	9
251	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	108,705	86,882	20,918	40	540	325
252	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	35,104	28,056	6,755	13	174	105
253	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	12,683	10,137	2,441	5	63	38
254	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
255	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
256	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	33,438	26,725	6,434	12	166	100
257	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	35	28	7	0	0	0
258	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	2,069,836	1,654,305	398,296	763	10,282	6,191
259	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
260	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
261										
262		Total General Plant			2,914,242	2,329,191	560,784	1,074	14,477	8,716
263										
264		CWIP w/o AFUDC	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
265										
266		TOTAL PLANT IN SERVICE - CUSTOMER			339,279,847	271,167,439	65,287,170	125,055	1,685,450	1,014,733
267										
268		TOTAL CWIP W/O AFUDC - CUSTOMER			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
269		Intangible Plant:								
270										
271	30100	Organization	6.4	P, S, T & D Plant - Demand	3,384	1,827	1,128	-	429	-
272	30200	Franchises & Consents	6.4	P, S, T & D Plant - Demand	48,698	26,294	16,227	-	6,176	-
273	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
274										
275		Total Intangible Plant:			52,082	28,122	17,355	0	6,605	0
276										
277		Production Plant:								
278										
279	32520	Producing Leaseholds	3.0	Peak Day	0	-	-	-	-	-
280	32540	Rights of Ways	3.0	Peak Day	0	-	-	-	-	-
281	33100	Production Gas Wells Equipment	3.0	Peak Day	0	-	-	-	-	-
282	33201	Field Lines	3.0	Peak Day	0	-	-	-	-	-
283	33202	Tributary Lines	3.0	Peak Day	0	-	-	-	-	-
284	33400	Field Meas. & Reg. Sta. Equip	3.0	Peak Day	0	-	-	-	-	-
285	33600	Purification Equipment	3.0	Peak Day	0	-	-	-	-	-
286										
287		Total Production Plant			0	0	0	0	0	0
288										
289		Storage Plant:								
290										
291	35010	Land	3.0	Peak Day	130,563	70,498	43,507	-	16,558	-
292	35020	Rights of Way	3.0	Peak Day	2,341	1,264	780	-	297	-
293	35100	Structures and Improvements	3.0	Peak Day	8,958	4,837	2,985	-	1,136	-
294	35102	Compression Station Equipment	3.0	Peak Day	111,754	60,342	37,240	-	14,172	-
295	35103	Meas. & Reg. Sta. Structues	3.0	Peak Day	11,569	6,247	3,855	-	1,467	-
296	35104	Other Structures	3.0	Peak Day	68,721	37,106	22,900	-	8,715	-
297	35200	Wells \ Rights of Way	3.0	Peak Day	6,267,306	3,384,052	2,088,445	-	794,808	-
298	35201	Well Construction	3.0	Peak Day	849,999	458,960	283,244	-	107,795	-
299	35202	Well Equipment	3.0	Peak Day	333,680	180,171	111,192	-	42,317	-
300	35203	Cushion Gas	3.0	Peak Day	847,416	457,565	282,383	-	107,468	-
301	35210	Leaseholds	3.0	Peak Day	89,265	48,199	29,746	-	11,320	-
302	35211	Storage Rights	3.0	Peak Day	27,307	14,745	9,100	-	3,463	-
303	35301	Field Lines	3.0	Peak Day	87,675	47,341	29,216	-	11,119	-
304	35302	Tributary Lines	3.0	Peak Day	104,659	56,511	34,876	-	13,273	-
305	35400	Compressor Station Equipment	3.0	Peak Day	9,032,953	4,877,372	3,010,038	-	1,145,543	-
306	35500	Meas & Reg. Equipment	3.0	Peak Day	136,542	73,726	45,500	-	17,316	-
307	35600	Purification Equipment	3.0	Peak Day	663,749	358,393	221,180	-	84,175	-
308										
309		Total Storage Plant			18,774,458	10,137,330	6,256,185	0	2,380,942	0
310										
311		Transmission:								
312										
313	36510	Land & Land Rights	3.0	Peak Day	26,970	14,563	8,987	-	3,420	-
314	36520	Rights of Way	3.0	Peak Day	867,772	468,556	289,166	-	110,049	-
315	36602	Structures & Improvements	3.0	Peak Day	397,833	214,811	132,569	-	50,452	-
316	36603	Other Structues	3.0	Peak Day	60,826	32,843	20,269	-	7,714	-
317	36700	Mains Cathodic Protection	3.0	Peak Day	47,233	25,504	15,739	-	5,990	-
318	36701	Mains - Steel	3.0	Peak Day	27,826,921	15,025,237	9,272,724	-	3,528,959	-
319	36703	Mains - Anodes	3.0	Peak Day	11,134	6,012	3,710	-	1,412	-
320	36900	Meas. & Reg. Equipment	3.0	Peak Day	1,999,587	1,079,684	666,320	-	253,584	-
321	36901	Meas. & Reg. Equipment	3.0	Peak Day	2,269,499	1,225,424	756,262	-	287,814	-
322										
323		Total Transmission Plant			33,507,777	18,092,634	11,165,748	0	4,249,395	0
324										
325		Distribution:								
326										
327	37400	Land & Land Rights	3.0	Peak Day	378,568	204,409	126,150	-	48,009	-
328	37401	Land	3.0	Peak Day	264,560	142,850	88,159	-	33,551	-
329	37402	Land Rights	3.0	Peak Day	2,566,061	1,385,553	855,085	-	325,423	-
330	37403	Land Other	3.0	Peak Day	1,718	928	573	-	218	-
331	37500	Structures & Improvements	3.0	Peak Day	207,485	112,032	69,140	-	26,313	-
332	37501	Structures & Improvements T.B.	3.0	Peak Day	61,608	33,266	20,530	-	7,813	-
333	37502	Land Rights	3.0	Peak Day	28,555	15,418	9,515	-	3,621	-
334	37503	Improvements	3.0	Peak Day	2,472	1,335	824	-	313	-
335	37600	Mains Cathodic Protection	3.0	Peak Day	2,109,788	1,139,187	703,042	-	267,559	-
336	37601	Mains - Steel	3.0	Peak Day	142,299,497	76,835,080	47,418,255	-	18,046,162	-
337	37602	Mains - Plastic	3.0	Peak Day	136,809,678	73,870,835	45,588,890	-	17,349,953	-
338	37603	Mains - Anodes	3.0	Peak Day	2,221,705	1,199,617	740,335	-	281,753	-
339	37604	Mains - Leak Clamps	3.0	Peak Day	4,190,761	2,262,815	1,396,481	-	531,465	-
340	37800	Meas & Reg. Sta. Equip - General	3.0	Peak Day	15,797,380	8,529,847	5,264,138	-	2,003,395	-
341	37900	Meas & Reg. Sta. Equip - City Gate	3.0	Peak Day	5,994,784	3,236,903	1,997,633	-	760,248	-
342	37905	Meas & Reg. Sta. Equipment T.b.	3.0	Peak Day	1,060,543	572,644	353,403	-	134,496	-
343	38000	Services	99.0	-	0	-	-	-	-	-
344	38100	Meters	99.0	-	0	-	-	-	-	-
345	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
346	38300	House Regulators	99.0	-	0	-	-	-	-	-
347	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
348	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
349	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
350										
351		Total Distribution Plant			313,995,162	169,542,718	104,632,151	0	39,820,292	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
352										
353		General:								
354										
355	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	492,327	265,833	164,057	-	62,436	-
356	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	3,761,212	2,030,879	1,253,343	-	476,990	-
357	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
358	39002	Structures-Brick	6.4	P, S, T & D Plant - Demand	70,339	37,980	23,439	-	8,920	-
359	39003	Improvements	6.4	P, S, T & D Plant - Demand	356,187	192,324	118,692	-	45,171	-
360	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	5,264	2,842	1,754	-	668	-
361	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	514,876	278,009	171,571	-	65,296	-
362	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	738,243	398,617	246,004	-	93,623	-
363	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
364	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
365	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	73,440	39,654	24,472	-	9,314	-
366	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
367	39202	Trailers	6.4	P, S, T & D Plant - Demand	14,866	8,027	4,954	-	1,885	-
368	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
369	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	2,902,437	1,567,181	967,175	-	368,082	-
370	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
371	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
372	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
373	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
374	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	176,314	95,201	58,753	-	22,360	-
375	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
376	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
377	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
378	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	1,211,992	654,419	403,870	-	153,703	-
379	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
380	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	8,705	4,700	2,901	-	1,104	-
381	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
382	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
383	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
384	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
385	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	215,614	116,421	71,849	-	27,344	-
386	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
387	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
388	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
389	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
390										
391		Total General Plant			10,541,815	5,692,088	3,512,834	0	1,336,894	0
392										
393		TOTAL DIRECT PLANT			376,871,294	203,492,892	125,584,273	0	47,794,128	0
394										
395		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
396										
397		Kentucky Mid-States General Office:								
398										
399		Intangible Plant:								
400										
401	30100	Organization	6.4	P, S, T & D Plant - Demand	37,624	20,315	12,537	-	4,771	-
402	30200	Franchises & Consents	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
403	30300	Misc Intangible Plant	6.4	P, S, T & D Plant - Demand	225,277	121,639	75,069	-	28,569	-
404										
405		Total Intangible Plant:			262,901	141,954	87,606	0	33,341	0
406										
407		General:								
408										
409	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
410	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	36,412	19,661	12,133	-	4,618	-
411	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
412	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
413	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	3,123	1,687	1,041	-	396	-
414	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	7,885	4,257	2,627	-	1,000	-
415	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	5,467	2,952	1,822	-	693	-
416	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
417	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
418	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	834	451	278	-	106	-
419	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
420	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
421	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
422	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	22,380	12,084	7,458	-	2,838	-
423	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	1,924	1,039	641	-	244	-
424	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
425	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
426	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
427	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
428	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
429	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
430	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
431	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
432	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
433	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
434	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
435	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	5,739	3,099	1,912	-	728	-
436	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
437	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
438	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
439	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	8,836	4,771	2,945	-	1,121	-
440	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
441	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
442	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
443										
444		Total General Plant			92,601	50,000	30,857	0	11,744	0
445										
446		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
447										
448		Shared Services General Office:								
449										
450		General:								
451										
452	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
453	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
454	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	196,338	106,014	65,426	-	24,899	-
455	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
456	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
457	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	261,005	140,930	86,974	-	33,100	-
458	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	156,095	84,284	52,015	-	19,796	-
459	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
460	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
461	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	5,847	3,157	1,948	-	741	-
462	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
463	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
464	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
465	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	559	302	186	-	71	-
466	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
467	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
468	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
469	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
470	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	14,303	7,723	4,766	-	1,814	-
471	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
472	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
473	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
474	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	2,241	1,210	747	-	284	-
475	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
476	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	1,067,896	576,614	355,854	-	135,429	-
477	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	859,448	464,062	286,393	-	108,994	-
478	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	118,663	64,073	39,542	-	15,049	-
479	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
480	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
481	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	87,298	47,137	29,090	-	11,071	-
482	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	1,534	828	511	-	194	-
483	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	2,007,304	1,083,850	668,891	-	254,563	-
484	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	672,382	363,055	224,057	-	85,270	-
485	39931	Other Tang. Property - ALGN	6.4	P, S, T & D Plant - Demand	324,780	175,366	108,226	-	41,188	-
486										
487		Total General Plant			5,775,694	3,118,605	1,924,626	0	732,463	0
488										
489		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
490										
491		Shared Services Customer Support:								
492										
493		General:								
494										
495	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	85,825	46,341	28,599	-	10,884	-
496	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
497	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	450,173	243,072	150,011	-	57,090	-
498	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
499	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
500	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	69,451	37,501	23,143	-	8,808	-
501	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	71,681	38,704	23,886	-	9,090	-
502	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
503	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
504	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	909	491	303	-	115	-
505	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
506	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
507	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
508	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	8,638	4,664	2,878	-	1,095	-
509	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
510	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
511	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
512	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
513	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	43,032	23,235	14,339	-	5,457	-
514	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
515	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
516	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
517	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	12,125	6,547	4,040	-	1,538	-
518	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	3,346	1,806	1,115	-	424	-
519	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	123,777	66,834	41,246	-	15,697	-
520	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	39,971	21,582	13,319	-	5,069	-
521	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	14,441	7,798	4,812	-	1,831	-
522	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
523	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
524	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	38,074	20,558	12,687	-	4,828	-
525	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	40	22	13	-	5	-
526	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	2,356,818	1,272,572	785,359	-	298,887	-
527	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
528	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
529										
530		Total General Plant			3,318,300	1,791,727	1,105,752	0	420,821	0
531										
532		CWIP w/o AFUDC	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
533										
534		TOTAL PLANT IN SERVICE - DEMAND			386,320,789	208,595,178	128,733,115	0	48,992,496	0
535										
536		TOTAL CWIP W/O AFUDC - DEMAND			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
537		Intangible Plant:								
538										
539	30100	Organization	6.6	P, S, T & D Plant - Commodity	1,973	595	424	12	452	491
540	30200	Franchises & Consents	6.6	P, S, T & D Plant - Commodity	28,387	8,557	6,094	176	6,501	7,059
541	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
542										
543		Total Intangible Plant:			30,360	9,152	6,517	189	6,952	7,550
544										
545		Production Plant:								
546										
547	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
548	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
549	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
550	33201	Field Lines	99.0	-	0	-	-	-	-	-
551	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
552	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
553	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
554										
555		Total Production Plant			0	0	0	0	0	0
556										
557		Storage Plant:								
558										
559	35010	Land	1.5	Winter Volumes	130,563	49,601	32,736	705	23,252	24,269
560	35020	Rights of Way	1.5	Winter Volumes	2,341	889	587	13	417	435
561	35100	Structures and Improvements	1.5	Winter Volumes	8,958	3,403	2,246	48	1,595	1,665
562	35102	Compression Station Equipment	1.5	Winter Volumes	111,754	42,456	28,020	604	19,903	20,772
563	35103	Meas. & Reg. Sta. Structues	1.5	Winter Volumes	11,569	4,395	2,901	62	2,060	2,150
564	35104	Other Structures	1.5	Winter Volumes	68,721	26,107	17,230	371	12,239	12,774
565	35200	Wells \ Rights of Way	1.5	Winter Volumes	6,267,306	2,380,970	1,571,376	33,854	1,116,163	1,164,943
566	35201	Well Construction	1.5	Winter Volumes	849,999	322,918	213,117	4,591	151,379	157,995
567	35202	Well Equipment	1.5	Winter Volumes	333,680	126,766	83,662	1,802	59,426	62,023
568	35203	Cushion Gas	1.5	Winter Volumes	847,416	321,936	212,469	4,577	150,919	157,515
569	35210	Leaseholds	1.5	Winter Volumes	89,265	33,912	22,381	482	15,897	16,592
570	35211	Storage Rights	1.5	Winter Volumes	27,307	10,374	6,847	148	4,863	5,076
571	35301	Field Lines	1.5	Winter Volumes	87,675	33,308	21,982	474	15,614	16,297
572	35302	Tributary Lines	1.5	Winter Volumes	104,659	39,760	26,241	565	18,639	19,454
573	35400	Compressor Station Equipment	1.5	Winter Volumes	9,032,953	3,431,648	2,264,795	48,793	1,608,705	1,679,011
574	35500	Meas & Reg. Equipment	1.5	Winter Volumes	136,542	51,873	34,235	738	24,317	25,380
575	35600	Purification Equipment	1.5	Winter Volumes	663,749	252,160	166,419	3,585	118,209	123,375
576										
577		Total Storage Plant			18,774,458	7,132,478	4,707,243	101,414	3,343,599	3,489,724
578										
579		Transmission:								
580										
581	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
582	36520	Rights of Way	99.0	-	0	-	-	-	-	-
583	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
584	36603	Other Structues	99.0	-	0	-	-	-	-	-
585	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
586	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
587	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
588	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
589	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
590										
591		Total Transmission Plant			0	0	0	0	0	0
592										
593		Distribution:								
594										
595	37400	Land & Land Rights	1.0	Mcf	234,788	69,001	49,586	1,477	54,917	59,808
596	37401	Land	1.0	Mcf	164,081	48,221	34,653	1,032	38,379	41,796
597	37402	Land Rights	1.0	Mcf	1,591,476	467,709	336,111	10,010	372,247	405,397
598	37403	Land Other	1.0	Mcf	1,066	313	225	7	249	271
599	37500	Structures & Improvements	1.0	Mcf	128,683	37,818	27,177	809	30,099	32,779
600	37501	Structures & Improvements T.B.	1.0	Mcf	38,210	11,229	8,070	240	8,937	9,733
601	37502	Land Rights	1.0	Mcf	17,710	5,205	3,740	111	4,142	4,511
602	37503	Improvements	1.0	Mcf	1,533	451	324	10	359	391
603	37600	Mains Cathodic Protection	1.0	Mcf	1,308,495	384,546	276,347	8,230	306,058	333,313
604	37601	Mains - Steel	1.0	Mcf	88,254,422	25,936,576	18,638,880	555,117	20,642,775	22,481,075
605	37602	Mains - Plastic	1.0	Mcf	84,849,626	24,935,960	17,919,804	533,701	19,846,390	21,613,770
606	37603	Mains - Anodes	1.0	Mcf	1,377,906	404,945	291,007	8,667	322,293	350,994
607	37604	Mains - Leak Clamps	1.0	Mcf	2,599,118	763,840	548,920	16,348	607,936	662,074
608	37800	Meas & Reg. Sta. Equip - General	1.0	Mcf	9,797,566	2,879,349	2,069,195	61,626	2,291,658	2,495,737
609	37900	Meas & Reg. Sta. Equip - City Gate	1.0	Mcf	3,717,977	1,092,654	785,218	23,386	869,638	947,081
610	37905	Meas & Reg. Sta. Equipment T.b.	1.0	Mcf	657,751	193,302	138,914	4,137	153,848	167,549
611	38000	Services	99.0	-	0	-	-	-	-	-
612	38100	Meters	99.0	-	0	-	-	-	-	-
613	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
614	38300	House Regulators	99.0	-	0	-	-	-	-	-
615	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
616	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
617	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
618										
619		Total Distribution Plant			194,740,405	57,231,118	41,128,171	1,224,911	45,549,925	49,606,280

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
620										
621		General:								
622										
623	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	286,993	86,513	61,609	1,783	65,720	71,368
624	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	2,192,531	660,934	470,672	13,620	502,075	545,230
625	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
626	39002	Structures-Brick	6.6	P, S, T & D Plant - Commodity	41,003	12,360	8,802	255	9,389	10,196
627	39003	Improvements	6.6	P, S, T & D Plant - Commodity	207,633	62,590	44,573	1,290	47,547	51,633
628	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	3,068	925	659	19	703	763
629	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	300,138	90,476	64,431	1,864	68,730	74,637
630	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	430,346	129,727	92,383	2,673	98,546	107,017
631	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
632	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
633	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	42,811	12,905	9,190	266	9,803	10,646
634	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
635	39202	Trailers	6.6	P, S, T & D Plant - Commodity	8,666	2,612	1,860	54	1,984	2,155
636	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
637	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	1,691,924	510,027	363,207	10,510	387,440	420,741
638	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
639	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
640	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
641	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
642	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	102,779	30,983	22,064	638	23,536	25,559
643	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
644	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
645	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
646	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	706,509	212,976	151,667	4,389	161,786	175,692
647	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
648	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	5,075	1,530	1,089	32	1,162	1,262
649	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
650	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
651	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
652	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
653	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	125,688	37,888	26,982	781	28,782	31,256
654	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
655	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
656	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
657	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
658										
659		Total General Plant			6,145,163	1,852,446	1,319,187	38,173	1,407,203	1,528,154
660										
661		TOTAL DIRECT PLANT			219,690,386	66,225,194	47,161,118	1,364,686	50,307,679	54,631,708
662										
663		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
664										
665		Kentucky Mid-States General Office:								
666										
667		Intangible Plant:								
668										
669	30100	Organization	6.6	P, S, T & D Plant - Commodity	21,932	6,611	4,708	136	5,022	5,454
670	30200	Franchises & Consents	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
671	30300	Misc Intangible Plant	6.6	P, S, T & D Plant - Commodity	131,321	39,586	28,191	816	30,072	32,656
672										
673		Total Intangible Plant:			153,253	46,198	32,899	952	35,094	38,110
674										
675		General:								
676										
677	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
678	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	21,226	6,398	4,557	132	4,861	5,278
679	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
680	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
681	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	1,821	549	391	11	417	453
682	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	4,596	1,386	987	29	1,052	1,143
683	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	3,187	961	684	20	730	793
684	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
685	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
686	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	486	147	104	3	111	121
687	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
688	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
689	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
690	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	13,046	3,933	2,801	81	2,987	3,244
691	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	1,122	338	241	7	257	279
692	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
693	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
694	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
695	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
696	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
697	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
698	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
699	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
700	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
701	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
702	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
703	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	3,345	1,008	718	21	766	832
704	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
705	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
706	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
707	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	5,151	1,553	1,106	32	1,180	1,281
708	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
709	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
710	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
711										
712		Total General Plant			53,980	16,272	11,588	335	12,361	13,424
713										
714		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
715										
716		Shared Services General Office:								
717										
718		General:								
719										
720	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
721	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
722	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	114,452	34,501	24,570	711	26,209	28,461
723	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
724	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
725	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	152,148	45,865	32,662	945	34,841	37,836
726	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	90,993	27,430	19,534	565	20,837	22,628
727	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
728	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
729	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	3,408	1,027	732	21	780	848
730	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
731	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
732	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
733	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	326	98	70	2	75	81
734	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
735	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
736	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
737	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
738	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	8,338	2,513	1,790	52	1,909	2,073
739	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
740	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
741	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
742	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	1,306	394	280	8	299	325
743	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
744	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	622,511	187,655	133,635	3,867	142,551	154,804
745	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	501,000	151,025	107,550	3,112	114,726	124,587
746	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	69,173	20,852	14,849	430	15,840	17,202
747	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
748	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
749	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	50,889	15,340	10,924	316	11,653	12,655
750	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	894	269	192	6	205	222
751	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	1,170,122	352,731	251,191	7,269	267,950	290,981
752	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	391,953	118,153	84,141	2,435	89,755	97,469
753	39931	Other Tang. Property - ALGN	6.6	P, S, T & D Plant - Commodity	189,325	57,072	40,643	1,176	43,354	47,081
754										
755		Total General Plant			3,366,838	1,014,926	722,762	20,914	770,984	837,251
756										
757		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
758										
759		Shared Services Customer Support:								
760										
761		General:								
762										
763	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	50,030	15,081	10,740	311	11,457	12,441
764	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
765	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	262,420	79,106	56,334	1,630	60,093	65,258
766	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
767	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
768	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	40,485	12,204	8,691	251	9,271	10,068
769	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	41,785	12,596	8,970	260	9,568	10,391
770	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
771	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
772	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	530	160	114	3	121	132
773	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
774	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
775	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
776	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	5,035	1,518	1,081	31	1,153	1,252
777	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
778	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
779	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
780	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
781	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	25,085	7,562	5,385	156	5,744	6,238
782	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
783	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
784	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
785	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	7,068	2,131	1,517	44	1,619	1,758
786	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	1,950	588	419	12	447	485
787	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	72,153	21,751	15,489	448	16,523	17,943
788	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	23,300	7,024	5,002	145	5,336	5,794
789	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	8,418	2,538	1,807	52	1,928	2,093
790	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
791	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
792	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	22,195	6,691	4,765	138	5,082	5,519
793	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	23	7	5	0	5	6
794	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	1,373,865	414,149	294,929	8,534	314,606	341,647
795	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
796	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
797										
798		Total General Plant			1,934,343	583,104	415,247	12,016	442,952	481,025
799										
800		CWIP w/o AFUDC	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
801										
802		TOTAL PLANT IN SERVICE - COMMODITY			225,198,801	67,885,694	48,343,614	1,398,904	51,569,070	56,001,518
803										
804		TOTAL CWIP W/O AFUDC - COMMODITY			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF PLANT IN SERVICE

Total Plant in Service

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
805		Intangible Plant:								
806										
807	30100	Organization			8,330	4,798	2,123	13	896	500
808	30200	Franchises & Consents			119,853	69,034	30,551	192	12,889	7,187
809	30300	Misc Intangible Plant			0	-	-	-	-	-
810										
811		Total Intangible Plant:			128,182	73,831	32,674	205	13,784	7,687
812										
813		Production Plant:								
814										
815	32520	Producing Leaseholds			0	-	-	-	-	-
816	32540	Rights of Ways			0	-	-	-	-	-
817	33100	Production Gas Wells Equipment			0	-	-	-	-	-
818	33201	Field Lines			0	-	-	-	-	-
819	33202	Tributary Lines			0	-	-	-	-	-
820	33400	Field Meas. & Reg. Sta. Equip			0	-	-	-	-	-
821	33600	Purification Equipment			0	-	-	-	-	-
822										
823		Total Production Plant			0	0	0	0	0	0
824										
825		Storage Plant:								
826										
827	35010	Land			261,127	120,100	76,243	705	39,810	24,269
828	35020	Rights of Way			4,682	2,153	1,367	13	714	435
829	35100	Structures and Improvements			17,916	8,240	5,231	48	2,731	1,665
830	35102	Compression Station Equipment			223,508	102,798	65,259	604	34,075	20,772
831	35103	Meas. & Reg. Sta. Structues			23,138	10,642	6,756	62	3,528	2,150
832	35104	Other Structures			137,443	63,214	40,130	371	20,954	12,774
833	35200	Wells \ Rights of Way			12,534,611	5,765,022	3,659,821	33,854	1,910,971	1,164,943
834	35201	Well Construction			1,699,999	781,877	496,361	4,591	259,174	157,995
835	35202	Well Equipment			667,359	306,937	194,854	1,802	101,743	62,023
836	35203	Cushion Gas			1,694,833	779,502	494,853	4,577	258,387	157,515
837	35210	Leaseholds			178,530	82,111	52,127	482	27,218	16,592
838	35211	Storage Rights			54,614	25,119	15,946	148	8,326	5,076
839	35301	Field Lines			175,350	80,649	51,198	474	26,733	16,297
840	35302	Tributary Lines			209,319	96,272	61,116	565	31,912	19,454
841	35400	Compressor Station Equipment			18,065,905	8,309,021	5,274,833	48,793	2,754,248	1,679,011
842	35500	Meas & Reg. Equipment			273,084	125,599	79,734	738	41,633	25,380
843	35600	Purification Equipment			1,327,498	610,554	387,599	3,585	202,384	123,375
844										
845		Total Storage Plant			37,548,916	17,269,809	10,963,428	101,414	5,724,541	3,489,724
846										
847		Transmission:								
848										
849	36510	Land & Land Rights			26,970	14,563	8,987	-	3,420	-
850	36520	Rights of Way			867,772	468,556	289,166	-	110,049	-
851	36602	Structures & Improvements			397,833	214,811	132,569	-	50,452	-
852	36603	Other Structues			60,826	32,843	20,269	-	7,714	-
853	36700	Mains Cathodic Protection			47,233	25,504	15,739	-	5,990	-
854	36701	Mains - Steel			27,826,921	15,025,237	9,272,724	-	3,528,959	-
855	36703	Mains - Anodes			11,134	6,012	3,710	-	1,412	-
856	36900	Meas. & Reg. Equipment			1,999,587	1,079,684	666,320	-	253,584	-
857	36901	Meas. & Reg. Equipment			2,269,499	1,225,424	756,262	-	287,814	-
858										
859		Total Transmission Plant			33,507,777	18,092,634	11,165,748	0	4,249,395	0
860										
861		Distribution:								
862										
863	37400	Land & Land Rights			613,356	273,409	175,736	1,477	102,926	59,808
864	37401	Land			428,640	191,071	122,812	1,032	71,930	41,796
865	37402	Land Rights			4,157,536	1,853,262	1,191,196	10,010	697,670	405,397
866	37403	Land Other			2,784	1,241	798	7	467	271
867	37500	Structures & Improvements			336,168	149,850	96,317	809	56,412	32,779
868	37501	Structures & Improvements T.B.			99,818	44,495	28,599	240	16,750	9,733
869	37502	Land Rights			46,264	20,623	13,255	111	7,764	4,511
870	37503	Improvements			4,005	1,785	1,148	10	672	391
871	37600	Mains Cathodic Protection			3,418,283	1,523,733	979,389	8,230	573,617	333,313
872	37601	Mains - Steel			230,553,919	102,771,656	66,057,134	555,117	38,688,937	22,481,075
873	37602	Mains - Plastic			221,659,304	98,806,795	63,508,694	533,701	37,196,344	21,613,770
874	37603	Mains - Anodes			3,599,610	1,604,561	1,031,342	8,667	604,046	350,994
875	37604	Mains - Leak Clamps			6,789,879	3,026,655	1,945,402	16,348	1,139,400	662,074
876	37800	Meas & Reg. Sta. Equip - General			25,594,946	11,409,196	7,333,333	61,626	4,295,053	2,495,737
877	37900	Meas & Reg. Sta. Equip - City Gate			9,712,761	4,329,558	2,782,851	23,386	1,629,885	947,081
878	37905	Meas & Reg. Sta. Equipment T.b.			1,718,293	765,946	492,317	4,137	288,344	167,549
879	38000	Services			193,916,542	172,131,494	21,572,990	9,386	126,507	76,164
880	38100	Meters			55,920,540	38,934,861	15,880,938	48,900	659,055	396,787
881	38200	Meter Installaitons			61,761,518	43,001,661	17,539,724	54,007	727,894	438,232
882	38300	House Regulators			3,974,497	2,767,256	1,128,722	3,476	46,842	28,201
883	38400	House Reg. Installations			378,094	263,249	107,375	331	4,456	2,683
884	38500	Ind. Meas. & Reg. Sta. Equipment			5,725,878	-	5,670,142	2,467	33,251	20,019
885	38600	Other Prop. On Cust. Prem			0	-	-	-	-	-
886										
887		Total Distribution Plant			830,412,635	483,872,357	207,660,213	1,343,478	86,968,221	50,568,366

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
888										
889		General:								
890										
891	38900	Land & Land Rights			1,211,697	697,922	308,868	1,942	130,303	72,661
892	39000	Structures & Improvements			9,256,964	5,331,893	2,359,650	14,837	995,475	555,109
893	39001	Structures Frame			0	-	-	-	-	-
894	39002	Structures-Brick			173,115	99,712	44,128	277	18,616	10,381
895	39003	Improvements			876,634	504,930	223,459	1,405	94,271	52,569
896	39004	Air Conditioning Equipment			12,955	7,462	3,302	21	1,393	777
897	39009	Improvement to leased Premises			1,267,195	729,888	323,015	2,031	136,272	75,989
898	39100	Office Furniture & Equipment			1,816,939	1,046,533	463,147	2,912	195,390	108,956
899	39102	Remittance Processing Equip			0	-	-	-	-	-
900	39103	Office Machines			0	-	-	-	-	-
901	39200	Transportation Equipment			180,749	104,109	46,074	290	19,437	10,839
902	39201	Trucks			0	-	-	-	-	-
903	39202	Trailers			36,588	21,074	9,327	59	3,935	2,194
904	39300	Stores Equipment			0	-	-	-	-	-
905	39400	Tools, Shop & Garage Equipment			7,143,379	4,114,495	1,820,886	11,450	768,184	428,364
906	39600	Power Operated Equipment			0	-	-	-	-	-
907	39603	Ditchers			0	-	-	-	-	-
908	39604	Backhoes			0	-	-	-	-	-
909	39605	Welders			0	-	-	-	-	-
910	39700	Communication Equipment			433,938	249,943	110,613	696	46,665	26,022
911	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
912	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
913	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
914	39800	Miscellaneous Equipment			2,982,913	1,718,120	760,361	4,781	320,776	178,875
915	39900	Other Tangible Property			0	-	-	-	-	-
916	39901	Other Tangible Property - Servers - H/W			21,425	12,341	5,461	34	2,304	1,285
917	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
918	39903	Other Tangible Property - Network - H/W			0	-	-	-	-	-
919	39904	Other Tang. Property - CPU			0	-	-	-	-	-
920	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
921	39906	Other Tang. Property - PC Hardware			530,662	305,654	135,269	851	57,066	31,822
922	39907	Other Tang. Property - PC Software			0	-	-	-	-	-
923	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
924	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
925	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
926										
927		Total General Plant			25,945,153	14,944,076	6,613,559	41,585	2,790,088	1,555,844
928										
929		TOTAL DIRECT PLANT			927,542,664	534,252,707	236,435,623	1,486,683	99,746,031	55,621,621
930										
931		CWIP w/o AFUDC			0	-	-	-	-	-
932										
933		Kentucky Mid-States General Office:								
934										
935		Intangible Plant:								
936										
937	30100	Organization			92,599	53,336	23,604	148	9,958	5,553
938	30200	Franchises & Consents			0	-	-	-	-	-
939	30300	Misc Intangible Plant			554,443	319,352	141,331	889	59,624	33,248
940										
941		Total Intangible Plant:			647,042	372,688	164,934	1,037	69,582	38,801
942										
943		General:								
944										
945	37400	Land & Land Rights			0	-	-	-	-	-
946	39001	Structures Frame			89,615	51,617	22,843	144	9,637	5,374
947	36602	Structures & Improvements			0	-	-	-	-	-
948	38900	Land & Land Rights			0	-	-	-	-	-
949	39004	Air Conditioning Equipment			7,687	4,428	1,960	12	827	461
950	39009	Improvement to leased Premises			19,405	11,177	4,947	31	2,087	1,164
951	39100	Office Furniture & Equipment			13,456	7,750	3,430	22	1,447	807
952	39102	Remittance Processing Equip			0	-	-	-	-	-
953	39103	Office Machines			0	-	-	-	-	-
954	39200	Transportation Equipment			2,054	1,183	523	3	221	123
955	39201	Trucks			0	-	-	-	-	-
956	39202	Trailers			0	-	-	-	-	-
957	39300	Stores Equipment			0	-	-	-	-	-
958	39400	Tools, Shop & Garage Equipment			55,081	31,726	14,040	88	5,923	3,303
959	39600	Power Operated Equipment			4,736	2,728	1,207	8	509	284
960	39603	Ditchers			0	-	-	-	-	-
961	39604	Backhoes			0	-	-	-	-	-
962	39605	Welders			0	-	-	-	-	-
963	39700	Communication Equipment			0	-	-	-	-	-
964	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
965	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
966	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
967	39800	Miscellaneous Equipment			0	-	-	-	-	-
968	39900	Other Tangible Property			0	-	-	-	-	-
969	39901	Other Tangible Property - Servers - H/W			0	-	-	-	-	-
970	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
971	39903	Other Tangible Property - Network - H/W			14,125	8,136	3,600	23	1,519	847
972	39904	Other Tang. Property - CPU			0	-	-	-	-	-
973	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
974	39906	Other Tang. Property - PC Hardware			0	-	-	-	-	-
975	39907	Other Tang. Property - PC Software			21,748	12,527	5,544	35	2,339	1,304
976	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
977	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
978	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
979										
980		Total General Plant			227,907	131,272	58,095	365	24,509	13,667
981										
982		CWIP w/o AFUDC			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF PLANT IN SERVICE										
983										
984		Shared Services General Office:								
985										
986		General:								
987										
988	37400	Land & Land Rights			0	-	-	-	-	-
989	39001	Structures Frame			0	-	-	-	-	-
990	36602	Structures & Improvements			483,221	278,329	123,176	775	51,965	28,977
991	37503	Improvements			0	-	-	-	-	-
992	39004	Air Conditioning Equipment			0	-	-	-	-	-
993	39009	Improvement to leased Premises			642,376	370,001	163,745	1,030	69,080	38,521
994	39100	Office Furniture & Equipment			384,176	221,281	97,929	616	41,314	23,038
995	39102	Remittance Processing Equip			0	-	-	-	-	-
996	39103	Office Machines			0	-	-	-	-	-
997	39200	Transportation Equipment			14,389	8,288	3,668	23	1,547	863
998	39201	Trucks			0	-	-	-	-	-
999	39202	Trailers			0	-	-	-	-	-
1000	39300	Stores Equipment			0	-	-	-	-	-
1001	39400	Tools, Shop & Garage Equipment			1,375	792	350	2	148	82
1002	39600	Power Operated Equipment			0	-	-	-	-	-
1003	39603	Ditchers			0	-	-	-	-	-
1004	39604	Backhoes			0	-	-	-	-	-
1005	39605	Welders			0	-	-	-	-	-
1006	39700	Communication Equipment			35,202	20,276	8,973	56	3,785	2,111
1007	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
1008	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
1009	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
1010	39800	Miscellaneous Equipment			5,516	3,177	1,406	9	593	331
1011	39900	Other Tangible Property			0	-	-	-	-	-
1012	39901	Other Tangible Property - Servers - H/W			2,628,270	1,513,850	669,960	4,213	282,639	157,609
1013	39902	Other Tangible Property - Servers - S/W			2,115,244	1,218,354	539,187	3,390	227,469	126,844
1014	39903	Other Tangible Property - Network - H/W			292,050	168,217	74,445	468	31,406	17,513
1015	39904	Other Tang. Property - CPU			0	-	-	-	-	-
1016	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
1017	39906	Other Tang. Property - PC Hardware			214,855	123,754	54,768	344	23,105	12,884
1018	39907	Other Tang. Property - PC Software			3,774	2,174	962	6	406	226
1019	39908	Other Tang. Property - Mainframe S/W			4,940,307	2,845,554	1,259,311	7,918	531,270	296,254
1020	39909	Other Tang. Property - Application Software			1,654,844	953,169	421,829	2,652	177,959	99,235
1021	39931	Other Tang. Property - ALGN			799,338	460,409	203,756	1,281	85,959	47,934
1022										
1023		Total General Plant			14,214,939	8,187,623	3,623,465	22,784	1,528,645	852,422
1024										
1025		CWIP w/o AFUDC			0	-	-	-	-	-
1026										
1027		Shared Services Customer Support:								
1028										
1029		General:								
1030										
1031	37400	Land & Land Rights			211,229	121,665	53,843	339	22,715	12,667
1032	39001	Structures Frame			0	-	-	-	-	-
1033	36602	Structures & Improvements			1,107,950	638,165	282,423	1,776	119,147	66,440
1034	37503	Improvements			0	-	-	-	-	-
1035	39004	Air Conditioning Equipment			0	-	-	-	-	-
1036	39009	Improvement to leased Premises			170,931	98,454	43,571	274	18,382	10,250
1037	39100	Office Furniture & Equipment			176,418	101,614	44,970	283	18,972	10,579
1038	39102	Remittance Processing Equip			0	-	-	-	-	-
1039	39103	Office Machines			0	-	-	-	-	-
1040	39200	Transportation Equipment			2,237	1,289	570	4	241	134
1041	39201	Trucks			0	-	-	-	-	-
1042	39202	Trailers			0	-	-	-	-	-
1043	39300	Stores Equipment			0	-	-	-	-	-
1044	39400	Tools, Shop & Garage Equipment			21,259	12,245	5,419	34	2,286	1,275
1045	39600	Power Operated Equipment			0	-	-	-	-	-
1046	39603	Ditchers			0	-	-	-	-	-
1047	39604	Backhoes			0	-	-	-	-	-
1048	39605	Welders			0	-	-	-	-	-
1049	39700	Communication Equipment			105,908	61,002	26,997	170	11,389	6,351
1050	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
1051	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
1052	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
1053	39800	Miscellaneous Equipment			29,842	17,188	7,607	48	3,209	1,790
1054	39900	Other Tangible Property			8,234	4,743	2,099	13	885	494
1055	39901	Other Tangible Property - Servers - H/W			304,635	175,466	77,653	488	32,760	18,268
1056	39902	Other Tangible Property - Servers - S/W			98,374	56,662	25,076	158	10,579	5,899
1057	39903	Other Tangible Property - Network - H/W			35,543	20,472	9,060	57	3,822	2,131
1058	39904	Other Tang. Property - CPU			0	-	-	-	-	-
1059	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
1060	39906	Other Tang. Property - PC Hardware			93,706	53,974	23,886	150	10,077	5,619
1061	39907	Other Tang. Property - PC Software			98	57	25	0	11	6
1062	39908	Other Tang. Property - Mainframe S/W			5,800,519	3,341,025	1,478,584	9,297	623,776	347,838
1063	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
1064	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
1065										
1066		Total General Plant			8,166,885	4,704,021	2,081,783	13,090	878,250	489,741
1067										
1068		CWIP w/o AFUDC			0	-	-	-	-	-
1069										
1070		TOTAL PLANT IN SERVICE			950,799,437	547,648,311	242,363,900	1,523,959	102,247,016	57,016,251
1071										
1072		TOTAL CWIP W/O AFUDC			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Intangible Plant:								
2										
3	30100	Organization	6.2	P, S, T & D Plant - Customer	2,972	2,376	572	1	15	9
4	30200	Franchises & Consents	6.2	P, S, T & D Plant - Customer	42,768	34,182	8,230	16	212	128
5	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
6										
7		Total Intangible Plant:			45,740	36,558	8,802	17	227	137
8										
9		Production Plant:								
10										
11	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
12	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
13	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
14	33201	Field Lines	99.0	-	0	-	-	-	-	-
15	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
17	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
18										
19		Total Production Plant			0	0	0	0	0	0
20										
21		Storage Plant:								
22										
23	35010	Land	99.0	-	0	-	-	-	-	-
24	35020	Rights of Way	99.0	-	0	-	-	-	-	-
25	35100	Structures and Improvements	99.0	-	0	-	-	-	-	-
26	35102	Compression Station Equipment	99.0	-	0	-	-	-	-	-
27	35103	Meas. & Reg. Sta. Structues	99.0	-	0	-	-	-	-	-
28	35104	Other Structures	99.0	-	0	-	-	-	-	-
29	35200	Wells \ Rights of Way	99.0	-	0	-	-	-	-	-
30	35201	Well Construction	99.0	-	0	-	-	-	-	-
31	35202	Well Equipment	99.0	-	0	-	-	-	-	-
32	35203	Cushion Gas	99.0	-	0	-	-	-	-	-
33	35210	Leaseholds	99.0	-	0	-	-	-	-	-
34	35211	Storage Rights	99.0	-	0	-	-	-	-	-
35	35301	Field Lines	99.0	-	0	-	-	-	-	-
36	35302	Tributary Lines	99.0	-	0	-	-	-	-	-
37	35400	Compressor Station Equipment	99.0	-	0	-	-	-	-	-
38	35500	Meas & Reg. Equipment	99.0	-	0	-	-	-	-	-
39	35600	Purification Equipment	99.0	-	0	-	-	-	-	-
40										
41		Total Storage Plant			0	-	-	-	-	-
42										
43		Transmission:								
44										
45	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
46	36520	Rights of Way	99.0	-	0	-	-	-	-	-
47	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
48	36603	Other Structues	99.0	-	0	-	-	-	-	-
49	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
50	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
51	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
52	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
53	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
54										
55		Total Transmission Plant			0	-	-	-	-	-
56										
57		Distribution:								
58										
59	37400	Land & Land Rights	2.0	Bills	0	-	-	-	-	-
60	37401	Land	2.0	Bills	0	-	-	-	-	-
61	37402	Land Rights	2.0	Bills	0	-	-	-	-	-
62	37403	Land Other	2.0	Bills	0	-	-	-	-	-
63	37500	Structures & Improvements	2.0	Bills	0	-	-	-	-	-
64	37501	Structures & Improvements T.B.	2.0	Bills	0	-	-	-	-	-
65	37502	Land Rights	2.0	Bills	0	-	-	-	-	-
66	37503	Improvements	2.0	Bills	0	-	-	-	-	-
67	37600	Mains Cathodic Protection	2.0	Bills	0	-	-	-	-	-
68	37601	Mains - Steel	2.0	Bills	0	-	-	-	-	-
69	37602	Mains - Plastic	2.0	Bills	0	-	-	-	-	-
70	37603	Mains - Anodes	2.0	Bills	0	-	-	-	-	-
71	37604	Mains - Leak Clamps	2.0	Bills	0	-	-	-	-	-
72	37800	Meas & Reg. Sta. Equip - General	2.0	Bills	0	-	-	-	-	-
73	37900	Meas & Reg. Sta. Equip - City Gate	2.0	Bills	0	-	-	-	-	-
74	37905	Meas & Reg. Sta. Equipment T.b.	2.0	Bills	0	-	-	-	-	-
75	38000	Services	2.0	Bills	38,828,841	34,466,716	4,319,663	1,879	25,331	15,251
76	38100	Meters	4.0	Meter Investment	23,998,006	16,708,691	6,815,221	20,985	282,830	170,279
77	38200	Meter Installaitons	4.0	Meter Investment	22,719,274	15,818,369	6,452,072	19,867	267,759	161,206
78	38300	House Regulators	4.0	Meter Investment	469,350	326,786	133,291	410	5,532	3,330
79	38400	House Reg. Installations	4.0	Meter Investment	130,024	90,530	36,926	114	1,532	923
80	38500	Ind. Meas. & Reg. Sta. Equipment	2.2	Non-Residential Bills	3,090,645	-	3,060,560	1,332	17,948	10,805
81	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
82										
83		Total Distribution Plant			89,236,139	67,411,092	20,817,734	44,587	600,932	361,794

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
84											
85		General:									
86											
87	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
88	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	702,419	561,404	135,166	259	3,489	2,101	
89	39002	Structures - Brick	6.2	P, S, T & D Plant - Customer	42,398	33,886	8,159	16	211	127	
90	39003	Improvements	6.2	P, S, T & D Plant - Customer	119,567	95,563	23,008	44	594	358	
91	39003	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	3,181	2,543	612	1	16	10	
92	39004	Improvement to Leased Premises	6.2	P, S, T & D Plant - Customer	452,181	361,403	87,013	167	2,246	1,352	
93	39009	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	525,872	420,300	101,193	194	2,612	1,573	
94	39100	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
95	Composite	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
96	39103	Transportation Equipment	6.2	P, S, T & D Plant - Customer	27,054	21,623	5,206	10	134	81	
97	39200	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
98	39201	Trailers	6.2	P, S, T & D Plant - Customer	3,089	2,469	595	1	15	9	
99	39202	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
100	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	1,193,882	954,203	229,737	440	5,931	3,571	
101	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
102	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
103	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
104	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
105	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	130,835	104,569	25,176	48	650	391	
106	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
107	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
108	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
109	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	552,721	441,759	106,359	204	2,746	1,653	
110	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
111	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	7,706	6,159	1,483	3	38	23	
112	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
113	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
114	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
115	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
116	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	189,125	151,157	36,393	70	940	566	
117	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
118	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
119	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
120		Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
121		Retirement Work in Progress	6.2	P, S, T & D Plant - Customer	(590,771)	(472,171)	(113,681)	(218)	(2,935)	(1,767)	
122		AR 15 general plant amortization	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
123											
124		Total General Plant			3,359,260	2,684,869	646,418	1,238	16,688	10,047	
125											
126		TOTAL DIRECT RESERVE FOR DEPRECIATION			92,641,139	70,132,518	21,472,953	45,842	617,847	371,978	
127											
128		Kentucky Mid-States General Office:									
129											
130		Intangible Plant:									
131											
132	30100	Organization	99.0	-	0	-	-	-	-	-	
133	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
134	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
135											
136		Total Intangible Plant:									
137											
138		General:									
139											
140	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
141	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	21,422	17,121	4,122	8	106	64	
142	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
143	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
144	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	2,735	2,186	526	1	14	8	
145	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	6,925	5,534	1,332	3	34	21	
146	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	1,520	1,215	293	1	8	5	
147	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
148	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
149	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	(353)	(282)	(68)	(0)	(2)	(1)	
150	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
151	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
152	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
153	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	9,604	7,676	1,848	4	48	29	
154	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	534	427	103	0	3	2	
155	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
156	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
157	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
158	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	(3,935)	(3,145)	(757)	(1)	(20)	(12)	
159	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
160	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
161	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
162	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	(22,645)	(18,098)	(4,357)	(8)	(112)	(68)	
163	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
164	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
165	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
166	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	3,483	2,784	670	1	17	10	
167	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
168	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
169	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
170	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	7,760	6,202	1,493	3	39	23	
171	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
172	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
173	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
174		Retirement Work in Progress	6.2	P, S, T & D Plant - Customer	9,364	7,484	1,802	3	47	28	
175											
176		Total General Plant			36,415	29,104	7,007	13	181	109	

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
177											
178		Shared Services General Office:									
179											
180		General:									
181											
182	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
183	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	56,501	45,158	10,872	21	281	169	
184	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
185	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
186	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
187	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	177,153	141,588	34,089	65	880	530	
188	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	68,882	55,054	13,255	25	342	206	
189	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	0	0	0	0	0	
190	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	0	0	0	0	0	
191	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	3,709	2,964	714	1	18	11	
192	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
193	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
194	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
195	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	452	361	87	0	2	1	
196	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
197	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
198	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
199	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
200	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	2,749	2,197	529	1	14	8	
201	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
202	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
203	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
204	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	903	722	174	0	4	3	
205	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	(0)	(0)	(0)	(0)	(0)	(0)	
206	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	212,422	169,777	40,876	78	1,055	635	
207	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	250,959	200,578	48,292	93	1,247	751	
208	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	34,162	27,304	6,574	13	170	102	
209	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
210	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
211	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	30,986	24,765	5,963	11	154	93	
212	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	1,134	906	218	0	6	3	
213	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
214	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	1,760,519	1,407,084	338,774	649	8,746	5,265	
215	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
216	ADJ	WTW Adjustment	6.2	P, S, T & D Plant - Customer	3,273	2,616	630	1	16	10	
217											
218		Total General Plant			2,603,804	2,081,075	501,046	960	12,935	7,788	
219					867,566	693,397	166,945	320	4,310	2,595	
220		Shared Services Customer Support:									
221											
222		General:									
223											
224	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
225	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
226	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	150,143	120,001	28,892	55	746	449	
227	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
228	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
229	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	48,855	39,047	9,401	18	243	146	
230	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	35,342	28,247	6,801	13	176	106	
231	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
232	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
233	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	803	642	155	0	4	2	
234	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
235	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
236	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
237	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	3,786	3,026	728	1	19	11	
238	39500	Laboratory Equipment	6.2	P, S, T & D Plant - Customer	1	1	0	0	0	0	
239	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
240	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
241	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
242	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	35,036	28,002	6,742	13	174	105	
243	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
244	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
245	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
246	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	3,603	2,880	693	1	18	11	
247	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	(2,968)	(2,372)	(571)	(1)	(15)	(9)	
248	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	74,227	59,326	14,283	27	369	222	
249	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	35,328	28,236	6,798	13	175	106	
250	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	6,322	5,053	1,216	2	31	19	
251	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
252	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
253	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	12,216	9,763	2,351	5	61	37	
254	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	(1,383)	(1,106)	(266)	(1)	(7)	(4)	
255	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	1,484,017	1,186,092	285,567	547	7,372	4,438	
256	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	2,124	1,697	409	1	11	6	
257	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
258		Retirement Work in Progress	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-	
259											
260		Total General Plant			1,887,452	1,508,535	363,200	696	9,376	5,645	
261											
262		TOTAL RESERVE FOR DEPRECIATION - CUSTOMER			97,168,809	73,751,233	22,344,207	47,511	640,339	385,519	

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
263		Intangible Plant:								
264										
265	30100	Organization	6.4	P, S, T & D Plant - Demand	3,384	1,827	1,128	-	429	-
266	30200	Franchises & Consents	6.4	P, S, T & D Plant - Demand	48,698	26,294	16,227	-	6,176	-
267	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
268										
269		Total Intangible Plant:			52,082	28,122	17,355	0	6,605	0
270										
271		Production Plant:								
272										
273	32520	Producing Leaseholds	3.0	Peak Day	0	-	-	-	-	-
274	32540	Rights of Ways	3.0	Peak Day	0	-	-	-	-	-
275	33100	Production Gas Wells Equipment	3.0	Peak Day	0	-	-	-	-	-
276	33201	Field Lines	3.0	Peak Day	0	-	-	-	-	-
277	33202	Tributary Lines	3.0	Peak Day	0	-	-	-	-	-
278	33400	Field Meas. & Reg. Sta. Equip	3.0	Peak Day	0	-	-	-	-	-
279	33600	Purification Equipment	3.0	Peak Day	0	-	-	-	-	-
280										
281		Total Production Plant			0	0	0	0	0	0
282										
283		Storage Plant:								
284										
285	35010	Land	3.0	Peak Day	0	-	-	-	-	-
286	35020	Rights of Way	3.0	Peak Day	2,100	1,134	700	-	266	-
287	35100	Structures and Improvements	3.0	Peak Day	3,931	2,123	1,310	-	499	-
288	35102	Compression Station Equipment	3.0	Peak Day	60,220	32,516	20,067	-	7,637	-
289	35103	Meas. & Reg. Sta. Structues	3.0	Peak Day	10,432	5,633	3,476	-	1,323	-
290	35104	Other Structures	3.0	Peak Day	53,002	28,618	17,662	-	6,722	-
291	35200	Wells \ Rights of Way	3.0	Peak Day	1,231,874	665,155	410,496	-	156,224	-
292	35201	Well Construction	3.0	Peak Day	751,264	405,647	250,343	-	95,274	-
293	35202	Well Equipment	3.0	Peak Day	237,180	128,066	79,035	-	30,079	-
294	35203	Cushion Gas	3.0	Peak Day	351,499	189,793	117,130	-	44,577	-
295	35210	Leaseholds	3.0	Peak Day	83,664	45,175	27,879	-	10,610	-
296	35211	Storage Rights	3.0	Peak Day	22,346	12,066	7,446	-	2,834	-
297	35301	Field Lines	3.0	Peak Day	52,783	28,500	17,589	-	6,694	-
298	35302	Tributary Lines	3.0	Peak Day	76,873	41,508	25,616	-	9,749	-
299	35400	Compressor Station Equipment	3.0	Peak Day	341,086	184,170	113,660	-	43,256	-
300	35500	Meas & Reg. Equipment	3.0	Peak Day	83,530	45,102	27,835	-	10,593	-
301	35600	Purification Equipment	3.0	Peak Day	161,314	87,102	53,754	-	20,458	-
302										
303		Total Storage Plant			3,523,099	1,902,309	1,173,997	-	446,793	-
304										
305		Transmission:								
306										
307	36510	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
308	36520	Rights of Way	3.0	Peak Day	587,414	317,176	195,743	-	74,495	-
309	36602	Structures & Improvements	3.0	Peak Day	29,122	15,724	9,704	-	3,693	-
310	36603	Other Structues	3.0	Peak Day	62,894	33,960	20,958	-	7,976	-
311	36700	Mains Cathodic Protection	3.0	Peak Day	33,163	17,907	11,051	-	4,206	-
312	36701	Mains - Steel	3.0	Peak Day	18,044,112	9,742,978	6,012,813	-	2,288,321	-
313	36703	Mains - Anodes	3.0	Peak Day	11,180	6,037	3,725	-	1,418	-
314	36900	Meas. & Reg. Equipment	3.0	Peak Day	620,559	335,073	206,788	-	78,698	-
315	36901	Meas. & Reg. Equipment	3.0	Peak Day	2,023,747	1,092,729	674,370	-	256,648	-
316										
317		Total Transmission Plant			21,412,190	11,561,582	7,135,153	-	2,715,455	-
318										
319		Distribution:								
320										
321	37400	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
322	37401	Land	3.0	Peak Day	0	-	-	-	-	-
323	37402	Land Rights	3.0	Peak Day	397,580	214,675	132,485	-	50,420	-
324	37403	Land Other	3.0	Peak Day	0	-	-	-	-	-
325	37500	Structures & Improvements	3.0	Peak Day	84,171	45,449	28,048	-	10,674	-
326	37501	Structures & Improvements T.B.	3.0	Peak Day	50,469	27,251	16,818	-	6,400	-
327	37502	Land Rights	3.0	Peak Day	25,127	13,567	8,373	-	3,187	-
328	37503	Improvements	3.0	Peak Day	1,361	735	453	-	173	-
329	37600	Mains Cathodic Protection	3.0	Peak Day	1,106,241	597,319	368,631	-	140,292	-
330	37601	Mains - Steel	3.0	Peak Day	19,103,139	10,314,802	6,365,711	-	2,422,625	-
331	37602	Mains - Plastic	3.0	Peak Day	17,314,058	9,348,783	5,769,538	-	2,195,737	-
332	37603	Mains - Anodes	3.0	Peak Day	1,142,550	616,924	380,730	-	144,896	-
333	37604	Mains - Leak Clamps	3.0	Peak Day	3,465,668	1,871,299	1,154,860	-	439,510	-
334	37800	Meas & Reg. Sta. Equip - General	3.0	Peak Day	3,263,900	1,762,353	1,087,625	-	413,922	-
335	37900	Meas & Reg. Sta. Equip - City Gate	3.0	Peak Day	899,055	485,448	299,591	-	114,017	-
336	37905	Meas & Reg. Sta. Equipment T.b.	3.0	Peak Day	659,398	356,044	219,730	-	83,624	-
337	38000	Services	99.0	-	0	-	-	-	-	-
338	38100	Meters	99.0	-	0	-	-	-	-	-
339	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
340	38300	House Regulators	99.0	-	0	-	-	-	-	-
341	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
342	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
343	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
344										
345		Total Distribution Plant			47,512,718	25,654,648	15,832,594	-	6,025,476	-

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
346											
347		General:									
348											
349	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
350	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	799,809	431,860	266,519	-	101,430	-	
351	39002	Structures - Brick	6.4	P, S, T & D Plant - Demand	48,277	26,067	16,087	-	6,122	-	
352	39003	Improvements	6.4	P, S, T & D Plant - Demand	136,145	73,512	45,367	-	17,266	-	
353	39003	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	3,622	1,956	1,207	-	459	-	
354	39004	Improvement to Leased Premises	6.4	P, S, T & D Plant - Demand	514,876	278,009	171,571	-	65,296	-	
355	39009	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	598,784	323,315	199,532	-	75,937	-	
356	39100	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
357	39102	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
358	39103	Transportation Equipment	6.4	P, S, T & D Plant - Demand	30,805	16,633	10,265	-	3,907	-	
359	39200	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
360	39201	Trailers	6.4	P, S, T & D Plant - Demand	3,518	1,899	1,172	-	446	-	
361	39202	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
362	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	1,359,413	734,019	452,995	-	172,398	-	
363	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
364	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
365	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
366	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
367	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	148,975	80,440	49,643	-	18,893	-	
368	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
369	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
370	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
371	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	629,355	339,822	209,719	-	79,814	-	
372	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
373	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	8,774	4,738	2,924	-	1,113	-	
374	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
375	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
376	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
377	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
378	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	215,347	116,277	71,760	-	27,310	-	
379	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
380	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
381	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
382		Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
383		Retirement Work in Progress	6.4	P, S, T & D Plant - Demand	(672,682)	(363,217)	(224,157)	-	(85,308)	-	
384		AR 15 general plant amortization	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
385											
386		Total General Plant			3,825,019	2,065,332	1,274,606	-	485,082	-	
387											
388		TOTAL DIRECT RESERVE FOR DEPRECIATION			76,325,108	41,211,993	25,433,705	0	9,679,411	0	
389											
390		Kentucky Mid-States General Office:									
391											
392		Intangible Plant:									
393											
394	30100	Organization	99.0	-	0	-	-	-	-	-	
395	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
396	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
397											
398		Total Intangible Plant:									
399											
400		General:									
401											
402	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
403	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	24,392	13,170	8,128	-	3,093	-	
404	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
405	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
406	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	3,115	1,682	1,038	-	395	-	
407	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	7,885	4,257	2,627	-	1,000	-	
408	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	1,731	935	577	-	220	-	
409	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
410	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
411	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	(402)	(217)	(134)	-	(51)	-	
412	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
413	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
414	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
415	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	10,936	5,905	3,644	-	1,387	-	
416	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	608	328	203	-	77	-	
417	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
418	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
419	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
420	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	(4,480)	(2,419)	(1,493)	-	(568)	-	
421	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
422	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
423	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
424	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	(25,784)	(13,922)	(8,592)	-	(3,270)	-	
425	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
426	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
427	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
428	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	3,966	2,141	1,321	-	503	-	
429	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
430	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
431	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
432	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	8,836	4,771	2,945	-	1,121	-	
433	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
434	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
435	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
436	ADJ	WTW Adjustment	6.4	P, S, T & D Plant - Demand	10,663	5,757	3,553	-	1,352	-	
437											
438		Total General Plant			41,464	22,388	13,817	-	5,258	-	

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
439											
440			Shared Services General Office:								
441											
442			General:								
443											
444		37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
445		39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	64,334	34,738	21,438	-	8,159	-
446		36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
447		37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
448		39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
449		39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	201,715	108,917	67,217	-	25,581	-
450		39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	78,433	42,350	26,136	-	9,947	-
451		39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	0	0	-	0	-
452		39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	0	0	-	0	-
453		39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	4,223	2,280	1,407	-	536	-
454		39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
455		39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
456		39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
457		39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	515	278	172	-	65	-
458		39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
459		39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
460		39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
461		39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
462		39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	3,130	1,690	1,043	-	397	-
463		39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
464		39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
465		39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
466		39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	1,028	555	343	-	130	-
467		39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	(0)	(0)	(0)	-	(0)	-
468		39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	241,874	130,601	80,599	-	30,674	-
469		39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	285,755	154,294	95,222	-	36,239	-
470		39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	38,899	21,003	12,962	-	4,933	-
471		39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
472		39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
473		39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	35,282	19,051	11,757	-	4,474	-
474		39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	1,291	697	430	-	164	-
475		39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
476		39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	2,004,614	1,082,398	667,995	-	254,221	-
477		39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
478			Retirement Work in Progress	6.4	P, S, T & D Plant - Demand	3,727	2,012	1,242	-	473	-
479											
480			Total General Plant			2,964,819	1,600,864	987,962	-	375,993	-
481											
482			Shared Services Customer Support:								
483											
484			General:								
485											
486		37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
487		39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
488		36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	170,961	92,311	56,969	-	21,681	-
489		37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
490		39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
491		39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	55,629	30,037	18,537	-	7,055	-
492		39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	40,242	21,729	13,410	-	5,103	-
493		39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
494		39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
495		39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	914	494	305	-	116	-
496		39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
497		39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
498		39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
499		39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	4,310	2,327	1,436	-	547	-
500		39500	Laboratory Equipment	6.4	P, S, T & D Plant - Demand	2	1	1	-	0	-
501		39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
502		39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
503		39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
504		39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	39,893	21,541	13,294	-	5,059	-
505		39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
506		39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
507		39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
508		39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	4,102	2,215	1,367	-	520	-
509		39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	(3,379)	(1,825)	(1,126)	-	(429)	-
510		39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	84,519	45,636	28,164	-	10,719	-
511		39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	40,226	21,720	13,404	-	5,101	-
512		39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	7,198	3,887	2,399	-	913	-
513		39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
514		39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
515		39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	13,909	7,510	4,635	-	1,764	-
516		39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	(1,575)	(850)	(525)	-	(200)	-
517		39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	1,689,775	912,399	563,081	-	214,294	-
518		39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	2,418	1,306	806	-	307	-
519		39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
520			Retirement Work in Progress	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-
521											
522			Total General Plant			2,149,146	1,160,438	716,157	-	272,551	-
523											
524			TOTAL RESERVE FOR DEPRECIATION - DEMAND			81,480,537	43,995,683	27,151,641	0	10,333,213	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
525		Intangible Plant:								
526										
527	30100	Organization	6.6	P, S, T & D Plant - Commodity	1,973	595	424	12	452	491
528	30200	Franchises & Consents	6.6	P, S, T & D Plant - Commodity	28,387	8,557	6,094	176	6,501	7,059
529	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
530										
531		Total Intangible Plant:			30,360	9,152	6,517	189	6,952	7,550
532										
533		Production Plant:								
534										
535	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
536	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
537	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
538	33201	Field Lines	99.0	-	0	-	-	-	-	-
539	33202	Tributary Lines	1.2	Sales Mcf	0	-	-	-	-	-
540	33400	Field Meas. & Reg. Sta. Equip	1.2	Sales Mcf	0	-	-	-	-	-
541	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
542										
543		Total Production Plant			0	0	0	0	0	0
544										
545		Storage Plant:								
546										
547	35010	Land	1.5	Winter Volumes	0	-	-	-	-	-
548	35020	Rights of Way	1.5	Winter Volumes	2,100	798	527	11	374	390
549	35100	Structures and Improvements	1.5	Winter Volumes	3,931	1,494	986	21	700	731
550	35102	Compression Station Equipment	1.5	Winter Volumes	60,220	22,878	15,099	325	10,725	11,193
551	35103	Meas. & Reg. Sta. Structues	1.5	Winter Volumes	10,432	3,963	2,616	56	1,858	1,939
552	35104	Other Structures	1.5	Winter Volumes	53,002	20,135	13,289	286	9,439	9,852
553	35200	Wells \ Rights of Way	1.5	Winter Volumes	1,231,874	467,993	308,863	6,654	219,388	228,976
554	35201	Well Construction	1.5	Winter Volumes	751,264	285,408	188,361	4,058	133,795	139,642
555	35202	Well Equipment	1.5	Winter Volumes	237,180	90,106	59,467	1,281	42,240	44,086
556	35203	Cushion Gas	1.5	Winter Volumes	351,499	133,536	88,130	1,899	62,600	65,335
557	35210	Leaseholds	1.5	Winter Volumes	83,664	31,784	20,977	452	14,900	15,551
558	35211	Storage Rights	1.5	Winter Volumes	22,346	8,489	5,603	121	3,980	4,154
559	35301	Field Lines	1.5	Winter Volumes	52,783	20,052	13,234	285	9,400	9,811
560	35302	Tributary Lines	1.5	Winter Volumes	76,873	29,204	19,274	415	13,691	14,289
561	35400	Compressor Station Equipment	1.5	Winter Volumes	341,086	129,580	85,519	1,842	60,745	63,400
562	35500	Meas & Reg. Equipment	1.5	Winter Volumes	83,530	31,733	20,943	451	14,876	15,526
563	35600	Purification Equipment	1.5	Winter Volumes	161,314	61,284	40,446	871	28,729	29,984
564										
565		Total Storage Plant			3,523,099	1,338,437	883,332	19,031	627,439	654,860
566										
567		Transmission:								
568										
569	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
570	36520	Rights of Way	99.0	-	0	-	-	-	-	-
571	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
572	36603	Other Structues	99.0	-	0	-	-	-	-	-
573	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
574	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
575	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
576	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
577	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
578										
579		Total Transmission Plant			0	-	-	-	-	-
580										
581		Distribution:								
582										
583	37400	Land & Land Rights	99.0	-	0	-	-	-	-	-
584	37401	Land	99.0	-	0	-	-	-	-	-
585	37402	Land Rights	1.0	Mcf	246,580	72,466	52,076	1,551	57,675	62,811
586	37403	Land Other	99.0	-	0	-	-	-	-	-
587	37500	Structures & Improvements	1.0	Mcf	52,203	15,342	11,025	328	12,210	13,298
588	37501	Structures & Improvements T.B.	1.0	Mcf	31,301	9,199	6,611	197	7,321	7,973
589	37502	Land Rights	1.0	Mcf	15,584	4,580	3,291	98	3,645	3,970
590	37503	Improvements	1.0	Mcf	844	248	178	5	197	215
591	37600	Mains Cathodic Protection	1.0	Mcf	686,093	201,632	144,899	4,316	160,478	174,769
592	37601	Mains - Steel	1.0	Mcf	11,847,804	3,481,882	2,502,195	74,522	2,771,210	3,017,994
593	37602	Mains - Plastic	1.0	Mcf	10,738,212	3,155,790	2,267,855	67,543	2,511,676	2,735,348
594	37603	Mains - Anodes	1.0	Mcf	708,612	208,250	149,655	4,457	165,745	180,505
595	37604	Mains - Leak Clamps	1.0	Mcf	2,149,414	631,679	453,945	13,520	502,750	547,521
596	37800	Meas & Reg. Sta. Equip - General	1.0	Mcf	2,024,277	594,903	427,517	12,733	473,480	515,645
597	37900	Meas & Reg. Sta. Equip - City Gate	1.0	Mcf	557,596	163,869	117,761	3,507	130,422	142,037
598	37905	Meas & Reg. Sta. Equipment T.b.	1.0	Mcf	408,960	120,187	86,370	2,572	95,656	104,174
599	38000	Services	99.0	-	0	-	-	-	-	-
600	38100	Meters	99.0	-	0	-	-	-	-	-
601	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
602	38300	House Regulators	99.0	-	0	-	-	-	-	-
603	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
604	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
605	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
606										
607		Total Distribution Plant			29,467,480	8,660,025	6,223,380	185,349	6,892,465	7,506,260

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF RESERVE FOR DEPRECIATION											
608											
609		General:									
610											
611	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
612	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	466,234	140,545	100,087	2,896	106,765	115,941	
613	39002	Structures - Brick	6.6	P, S, T & D Plant - Commodity	28,142	8,483	6,041	175	6,444	6,998	
614	39003	Improvements	6.6	P, S, T & D Plant - Commodity	79,363	23,924	17,037	493	18,174	19,736	
615	39003	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	2,112	637	453	13	484	525	
616	39004	Improvement to Leased Premises	6.6	P, S, T & D Plant - Commodity	300,138	90,476	64,431	1,864	68,730	74,637	
617	39009	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	349,050	105,220	74,931	2,168	79,930	86,800	
618	39100	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
619	39102	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
620	39103	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	17,957	5,413	3,855	112	4,112	4,466	
621	39200	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
622	39201	Trailers	6.6	P, S, T & D Plant - Commodity	2,051	618	440	13	470	510	
623	39202	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
624	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	792,445	238,881	170,115	4,923	181,465	197,062	
625	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
626	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
627	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
628	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
629	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	86,843	26,178	18,643	539	19,886	21,596	
630	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
631	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
632	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
633	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	366,871	110,593	78,757	2,279	84,011	91,232	
634	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
635	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	5,115	1,542	1,098	32	1,171	1,272	
636	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
637	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
638	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
639	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
640	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	125,532	37,841	26,948	780	28,746	31,217	
641	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
642	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
643	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
644		Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
645	ADJ	WTW Adjustment	6.6	P, S, T & D Plant - Commodity	(392,128)	(118,206)	(84,178)	(2,436)	(89,795)	(97,513)	
646		AR 15 general plant amortization	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
647											
648		Total General Plant			2,229,726	672,146	478,657	13,851	510,593	554,479	
649											
650		TOTAL DIRECT RESERVE FOR DEPRECIATION			35,250,665	10,679,760	7,591,887	218,420	8,037,450	8,723,149	
651											
652		Kentucky Mid-States General Office:									
653											
654		Intangible Plant:									
655											
656	30100	Organization	99.0	-	0	-	-	-	-	-	
657	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
658	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
659											
660		Total Intangible Plant:									
661											
662		General:									
663											
664	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
665	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	14,219	4,286	3,052	88	3,256	3,536	
666	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
667	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
668	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	1,816	547	390	11	416	452	
669	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	4,596	1,386	987	29	1,052	1,143	
670	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	1,009	304	217	6	231	251	
671	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
672	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
673	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	(235)	(71)	(50)	(1)	(54)	(58)	
674	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
675	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
676	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
677	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	6,375	1,922	1,368	40	1,460	1,585	
678	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	354	107	76	2	81	88	
679	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
680	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
681	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
682	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	(2,612)	(787)	(561)	(16)	(598)	(649)	
683	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
684	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
685	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
686	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	(15,030)	(4,531)	(3,227)	(93)	(3,442)	(3,738)	
687	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
688	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
689	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
690	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	2,312	697	496	14	529	575	
691	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
692	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
693	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
694	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	5,151	1,553	1,106	32	1,180	1,281	
695	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
696	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
697	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-	
698		Retirement Work in Progress	6.6	P, S, T & D Plant - Commodity	6,216	1,874	1,334	39	1,423	1,546	
699											
700		Total General Plant			24,171	7,286	5,189	150	5,535	6,011	

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF RESERVE FOR DEPRECIATION										
701										
702		Shared Services General Office:								
703										
704		General:								
705										
706	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
707	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	37,503	11,305	8,051	233	8,588	9,326
708	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
709	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
710	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
711	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	117,586	35,446	25,242	730	26,926	29,241
712	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	45,721	13,782	9,815	284	10,470	11,370
713	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
714	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	0	0	0	0	0
715	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	2,462	742	528	15	564	612
716	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
717	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
718	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
719	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	300	90	64	2	69	75
720	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
721	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
722	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
723	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
724	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	1,825	550	392	11	418	454
725	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
726	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
727	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
728	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	599	181	129	4	137	149
729	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	(0)	(0)	(0)	(0)	(0)	(0)
730	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	140,996	42,503	30,268	876	32,287	35,062
731	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	166,576	50,214	35,759	1,035	38,145	41,423
732	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	22,675	6,835	4,868	141	5,192	5,639
733	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
734	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
735	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	20,567	6,200	4,415	128	4,710	5,115
736	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	753	227	162	5	172	187
737	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
738	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	1,168,554	352,258	250,854	7,259	267,591	290,591
739	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
740		Retirement Work in Progress	6.6	P, S, T & D Plant - Commodity	2,173	655	466	13	497	540
741										
742		Total General Plant			1,728,289	520,989	371,013	10,736	395,767	429,784
743					575,851	173,589	123,618	3,577	131,866	143,200
744		Shared Services Customer Support:								
745										
746		General:								
747										
748	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
749	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
750	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	99,659	30,042	21,394	619	22,821	24,783
751	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
752	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
753	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	32,428	9,775	6,961	201	7,426	8,064
754	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	23,458	7,071	5,036	146	5,372	5,834
755	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
756	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
757	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	533	161	114	3	122	133
758	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
759	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
760	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
761	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	2,513	757	539	16	575	625
762	39500	Laboratory Equipment	6.6	P, S, T & D Plant - Commodity	1	0	0	0	0	0
763	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
764	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
765	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
766	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	23,255	7,010	4,992	144	5,325	5,783
767	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
768	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
769	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
770	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	2,391	721	513	15	548	595
771	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	(1,970)	(594)	(423)	(12)	(451)	(490)
772	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	49,269	14,852	10,577	306	11,282	12,252
773	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	23,449	7,069	5,034	146	5,370	5,831
774	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	4,196	1,265	901	26	961	1,043
775	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
776	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
777	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	8,108	2,444	1,741	50	1,857	2,016
778	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	(918)	(277)	(197)	(6)	(210)	(228)
779	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	985,024	296,933	211,456	6,119	225,564	244,952
780	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	1,410	425	303	9	323	351
781	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
782		Retirement Work in Progress	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
783										
784		Total General Plant			1,252,806	377,656	268,941	7,782	286,885	311,543
785										
786		TOTAL RESERVE FOR DEPRECIATION - COMMODITY			38,255,930	11,585,691	8,237,029	237,088	8,725,636	9,470,486

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF RESERVE FOR DEPRECIATION

Total Reserve for Depreciation

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
787		Intangible Plant:								
788										
789	30100	Organization			8,330	4,798	2,123	13	896	500
790	30200	Franchises & Consents			119,853	69,034	30,551	192	12,889	7,187
791	30300	Misc Intangible Plant			0	-	-	-	-	-
792										
793		Total Intangible Plant:			128,182	73,831	32,674	205	13,784	7,687
794										
795		Production Plant:								
796										
797	32520	Producing Leaseholds			0	-	-	-	-	-
798	32540	Rights of Ways			0	-	-	-	-	-
799	33100	Production Gas Wells Equipment			0	-	-	-	-	-
800	33201	Field Lines			0	-	-	-	-	-
801	33202	Tributary Lines			0	-	-	-	-	-
802	33400	Field Meas. & Reg. Sta. Equip			0	-	-	-	-	-
803	33600	Purification Equipment			0	-	-	-	-	-
804										
805		Total Production Plant			0	0	0	0	0	0
806										
807		Storage Plant:								
808										
809	35010	Land			0	-	-	-	-	-
810	35020	Rights of Way			4,200	1,932	1,226	11	640	390
811	35100	Structures and Improvements			7,863	3,616	2,296	21	1,199	731
812	35102	Compression Station Equipment			120,440	55,394	35,166	325	18,362	11,193
813	35103	Meas. & Reg. Sta. Structues			20,864	9,596	6,092	56	3,181	1,939
814	35104	Other Structures			106,003	48,754	30,951	286	16,161	9,852
815	35200	Wells \ Rights of Way			2,463,749	1,133,148	719,358	6,654	375,612	228,976
816	35201	Well Construction			1,502,528	691,055	438,704	4,058	229,069	139,642
817	35202	Well Equipment			474,361	218,172	138,502	1,281	72,319	44,086
818	35203	Cushion Gas			702,999	323,329	205,260	1,899	107,176	65,335
819	35210	Leaseholds			167,328	76,959	48,856	452	25,510	15,551
820	35211	Storage Rights			44,691	20,555	13,049	121	6,813	4,154
821	35301	Field Lines			105,566	48,553	30,823	285	16,094	9,811
822	35302	Tributary Lines			153,747	70,713	44,891	415	23,440	14,289
823	35400	Compressor Station Equipment			682,172	313,750	199,179	1,842	104,001	63,400
824	35500	Meas & Reg. Equipment			167,060	76,836	48,778	451	25,469	15,526
825	35600	Purification Equipment			322,628	148,386	94,200	871	49,186	29,984
826										
827		Total Storage Plant			7,046,197	3,240,745	2,057,329	19,031	1,074,232	654,860
828										
829		Transmission:								
830										
831	36510	Land & Land Rights			0	-	-	-	-	-
832	36520	Rights of Way			587,414	317,176	195,743	-	74,495	-
833	36602	Structures & Improvements			29,122	15,724	9,704	-	3,693	-
834	36603	Other Structues			62,894	33,960	20,958	-	7,976	-
835	36700	Mains Cathodic Protection			33,163	17,907	11,051	-	4,206	-
836	36701	Mains - Steel			18,044,112	9,742,978	6,012,813	-	2,288,321	-
837	36703	Mains - Anodes			11,180	6,037	3,725	-	1,418	-
838	36900	Meas. & Reg. Equipment			620,559	335,073	206,788	-	78,698	-
839	36901	Meas. & Reg. Equipment			2,023,747	1,092,729	674,370	-	256,648	-
840										
841		Total Transmission Plant			21,412,190	11,561,582	7,135,153	-	2,715,455	-
842										
843		Distribution:								
844										
845	37400	Land & Land Rights			0	-	-	-	-	-
846	37401	Land			0	-	-	-	-	-
847	37402	Land Rights			644,160	287,141	184,562	1,551	108,096	62,811
848	37403	Land Other			0	-	-	-	-	-
849	37500	Structures & Improvements			136,375	60,790	39,073	328	22,885	13,298
850	37501	Structures & Improvements T.B.			81,770	36,450	23,428	197	13,722	7,973
851	37502	Land Rights			40,711	18,147	11,664	98	6,832	3,970
852	37503	Improvements			2,204	983	632	5	370	215
853	37600	Mains Cathodic Protection			1,792,334	798,950	513,531	4,316	300,769	174,769
854	37601	Mains - Steel			30,950,942	13,796,684	8,867,906	74,522	5,193,835	3,017,994
855	37602	Mains - Plastic			28,052,270	12,504,573	8,037,394	67,543	4,707,413	2,735,348
856	37603	Mains - Anodes			1,851,162	825,173	530,385	4,457	310,641	180,505
857	37604	Mains - Leak Clamps			5,615,083	2,502,978	1,608,805	13,520	942,259	547,521
858	37800	Meas & Reg. Sta. Equip - General			5,288,177	2,357,256	1,515,141	12,733	887,402	515,645
859	37900	Meas & Reg. Sta. Equip - City Gate			1,456,651	649,316	417,352	3,507	244,439	142,037
860	37905	Meas & Reg. Sta. Equipment T.b.			1,068,358	476,231	306,101	2,572	179,280	104,174
861	38000	Services			38,828,841	34,466,716	4,319,663	1,879	25,331	15,251
862	38100	Meters			23,998,006	16,708,691	6,815,221	20,985	282,830	170,279
863	38200	Meter Installaitons			22,719,274	15,818,369	6,452,072	19,867	267,759	161,206
864	38300	House Regulators			469,350	326,786	133,291	410	5,532	3,330
865	38400	House Reg. Installations			130,024	90,530	36,926	114	1,532	923
866	38500	Ind. Meas. & Reg. Sta. Equipment			3,090,645	-	3,060,560	1,332	17,948	10,805
867	38600	Other Prop. On Cust. Prem			0	-	-	-	-	-
868										
869		Total Distribution Plant			166,216,337	101,725,765	42,873,708	229,937	13,518,873	7,868,053

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF RESERVE FOR DEPRECIATION										
870										
871		General:								
872										
873	38900	Land & Land Rights			0	-	-	-	-	-
874	39000	Structures & Improvements			1,968,463	1,133,809	501,772	3,155	211,684	118,042
875	39002	Structures - Brick			118,817	68,437	30,287	190	12,777	7,125
876	39003	Improvements			335,075	192,999	85,413	537	36,033	20,093
877	39003	Air Conditioning Equipment			8,916	5,135	2,273	14	959	535
878	39004	Improvement to Leased Premises			1,267,195	729,888	323,015	2,031	136,272	75,989
879	39009	Office Furniture & Equipment			1,473,706	848,836	375,656	2,362	158,479	88,373
880	39100	Remittance Processing Equip			0	-	-	-	-	-
881	39102	Office Machines			0	-	-	-	-	-
882	39103	Transportation Equipment			75,817	43,670	19,326	122	8,153	4,546
883	39200	Trucks			0	-	-	-	-	-
884	39201	Trailers			8,658	4,987	2,207	14	931	519
885	39202	Stores Equipment			0	-	-	-	-	-
886	39400	Tools, Shop & Garage Equipment			3,345,740	1,927,104	852,847	5,363	359,794	200,633
887	39600	Power Operated Equipment			0	-	-	-	-	-
888	39603	Ditchers			0	-	-	-	-	-
889	39604	Backhoes			0	-	-	-	-	-
890	39605	Welders			0	-	-	-	-	-
891	39700	Communication Equipment			366,653	211,187	93,462	588	39,429	21,987
892	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
893	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
894	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
895	39800	Miscellaneous Equipment			1,548,948	892,174	394,835	2,483	166,571	92,885
896	39900	Other Tangible Property			0	-	-	-	-	-
897	39901	Other Tangible Property - Servers - H/W			21,595	12,439	5,505	35	2,322	1,295
898	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
899	39903	Other Tangible Property - Network - H/W			0	-	-	-	-	-
900	39904	Other Tang. Property - CPU			0	-	-	-	-	-
901	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
902	39906	Other Tang. Property - PC Hardware			530,003	305,275	135,101	849	56,995	31,783
903	39907	Other Tang. Property - PC Software			0	-	-	-	-	-
904	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
905	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
906		Other Tang. Property - General Startup Costs			0	-	-	-	-	-
907	ADJ	WTW Adjustment			(1,655,581)	(953,593)	(422,016)	(2,654)	(178,038)	(99,280)
908		AR 15 general plant amortization			0	-	-	-	-	-
909										
910		Total General Plant			9,414,005	5,422,346	2,399,681	15,089	1,012,363	564,526
911										
912		TOTAL DIRECT RESERVE FOR DEPRECIATION			204,216,911	122,024,271	54,498,545	264,262	18,334,707	9,095,126
913										
914		Kentucky Mid-States General Office:								
915										
916		Intangible Plant:								
917										
918	30100	Organization			0	-	-	-	-	-
919	30200	Franchises & Consents			0	-	-	-	-	-
920	30300	Misc Intangible Plant			0	-	-	-	-	-
921										
922		Total Intangible Plant:								
923										
924		General:								
925										
926	37400	Land & Land Rights			0	-	-	-	-	-
927	39001	Structures Frame			60,032	34,578	15,302	96	6,456	3,600
928	36602	Structures & Improvements			0	-	-	-	-	-
929	38900	Land & Land Rights			0	-	-	-	-	-
930	39004	Air Conditioning Equipment			7,666	4,415	1,954	12	824	460
931	39009	Improvement to leased Premises			19,405	11,177	4,947	31	2,087	1,164
932	39100	Office Furniture & Equipment			4,261	2,454	1,086	7	458	255
933	39102	Remittance Processing Equip			0	-	-	-	-	-
934	39103	Office Machines			0	-	-	-	-	-
935	39200	Transportation Equipment			(990)	(570)	(252)	(2)	(107)	(59)
936	39201	Trucks			0	-	-	-	-	-
937	39202	Trailers			0	-	-	-	-	-
938	39300	Stores Equipment			0	-	-	-	-	-
939	39400	Tools, Shop & Garage Equipment			26,914	15,502	6,861	43	2,894	1,614
940	39600	Power Operated Equipment			1,496	862	381	2	161	90
941	39603	Ditchers			0	-	-	-	-	-
942	39604	Backhoes			0	-	-	-	-	-
943	39605	Welders			0	-	-	-	-	-
944	39700	Communication Equipment			(11,027)	(6,351)	(2,811)	(18)	(1,186)	(661)
945	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
946	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
947	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
948	39800	Miscellaneous Equipment			(63,459)	(36,552)	(16,176)	(102)	(6,824)	(3,805)
949	39900	Other Tangible Property			0	-	-	-	-	-
950	39901	Other Tangible Property - Servers - H/W			0	-	-	-	-	-
951	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-
952	39903	Other Tangible Property - Network - H/W			9,760	5,622	2,488	16	1,050	585
953	39904	Other Tang. Property - CPU			0	-	-	-	-	-
954	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
955	39906	Other Tang. Property - PC Hardware			0	-	-	-	-	-
956	39907	Other Tang. Property - PC Software			21,748	12,527	5,544	35	2,339	1,304
957	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
958	39909	Other Tang. Property - Application Software			0	-	-	-	-	-
959	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
960		Retirement Work in Progress			26,243	15,116	6,689	42	2,822	1,574
961										
962		Total General Plant			102,049	58,779	26,013	164	10,974	6,120

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF RESERVE FOR DEPRECIATION

963										
964		Shared Services General Office:								
965										
966		General:								
967										
968	37400	Land & Land Rights			0	-	-	-	-	-
969	39000	Structures & Improvements			158,337	91,200	40,361	254	17,027	9,495
970	36602	Structures & Improvements			0	-	-	-	-	-
971	37503	Improvements			0	-	-	-	-	-
972	39004	Air Conditioning Equipment			0	-	-	-	-	-
973	39009	Improvement to leased Premises			496,454	285,951	126,549	796	53,388	29,771
974	39100	Office Furniture & Equipment			193,036	111,186	49,206	309	20,759	11,576
975	39102	Remittance Processing Equip			0	0	0	0	0	0
976	39103	Office Machines			0	0	0	0	0	0
977	39200	Transportation Equipment			10,393	5,986	2,649	17	1,118	623
978	39201	Trucks			0	-	-	-	-	-
979	39202	Trailers			0	-	-	-	-	-
980	39300	Stores Equipment			0	-	-	-	-	-
981	39400	Tools, Shop & Garage Equipment			1,267	730	323	2	136	76
982	39600	Power Operated Equipment			0	-	-	-	-	-
983	39603	Ditchers			0	-	-	-	-	-
984	39604	Backhoes			0	-	-	-	-	-
985	39605	Welders			0	-	-	-	-	-
986	39700	Communication Equipment			7,704	4,437	1,964	12	828	462
987	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
988	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
989	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
990	39800	Miscellaneous Equipment			2,531	1,458	645	4	272	152
991	39900	Other Tangible Property			(0)	(0)	(0)	(0)	(0)	(0)
992	39901	Other Tangible Property - Servers - H/W			595,292	342,881	151,743	954	64,016	35,698
993	39902	Other Tangible Property - Servers - S/W			703,290	405,086	179,272	1,127	75,630	42,174
994	39903	Other Tangible Property - Network - H/W			95,736	55,143	24,404	153	10,295	5,741
995	39904	Other Tang. Property - CPU			0	-	-	-	-	-
996	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
997	39906	Other Tang. Property - PC Hardware			86,835	50,016	22,135	139	9,338	5,207
998	39907	Other Tang. Property - PC Software			3,178	1,831	810	5	342	191
999	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-
1000	39909	Other Tang. Property - Application Software			4,933,686	2,841,740	1,257,623	7,908	530,558	295,857
1001	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
1002		Retirement Work in Progress			9,173	5,283	2,338	15	986	550
1003										
1004		Total General Plant			7,296,912	4,202,928	1,860,022	11,696	784,695	437,571
1005										
1006		Shared Services Customer Support:								
1007										
1008		General:								
1009										
1010	37400	Land & Land Rights			0	-	-	-	-	-
1011	39001	Structures Frame			0	-	-	-	-	-
1012	36602	Structures & Improvements			420,763	242,354	107,255	674	45,248	25,232
1013	37503	Improvements			0	-	-	-	-	-
1014	39004	Air Conditioning Equipment			0	-	-	-	-	-
1015	39009	Improvement to leased Premises			136,913	78,860	34,900	219	14,723	8,210
1016	39100	Office Furniture & Equipment			99,042	57,047	25,246	159	10,651	5,939
1017	39102	Remittance Processing Equip			0	-	-	-	-	-
1018	39103	Office Machines			0	-	-	-	-	-
1019	39200	Transportation Equipment			2,251	1,296	574	4	242	135
1020	39201	Trucks			0	-	-	-	-	-
1021	39202	Trailers			0	-	-	-	-	-
1022	39300	Stores Equipment			0	-	-	-	-	-
1023	39400	Tools, Shop & Garage Equipment			10,609	6,111	2,704	17	1,141	636
1024	39500	Laboratory Equipment			4	2	1	0	0	0
1025	39603	Ditchers			0	-	-	-	-	-
1026	39604	Backhoes			0	-	-	-	-	-
1027	39605	Welders			0	-	-	-	-	-
1028	39700	Communication Equipment			98,184	56,553	25,028	157	10,559	5,888
1029	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-
1030	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-
1031	39705	Communication Equip. - Telemetering			0	-	-	-	-	-
1032	39800	Miscellaneous Equipment			10,096	5,815	2,574	16	1,086	605
1033	39900	Other Tangible Property			(8,317)	(4,790)	(2,120)	(13)	(894)	(499)
1034	39901	Other Tangible Property - Servers - H/W			208,015	119,814	53,024	333	22,370	12,474
1035	39902	Other Tangible Property - Servers - S/W			99,003	57,025	25,236	159	10,647	5,937
1036	39903	Other Tangible Property - Network - H/W			17,716	10,204	4,516	28	1,905	1,062
1037	39904	Other Tang. Property - CPU			0	-	-	-	-	-
1038	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-
1039	39906	Other Tang. Property - PC Hardware			34,234	19,718	8,726	55	3,681	2,053
1040	39907	Other Tang. Property - PC Software			(3,876)	(2,233)	(988)	(6)	(417)	(232)
1041	39908	Other Tang. Property - Mainframe S/W			4,158,816	2,395,425	1,060,105	6,666	447,230	249,390
1042	39909	Other Tang. Property - Application Software			5,952	3,428	1,517	10	640	357
1043	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-
1044		Retirement Work in Progress			0	-	-	-	-	-
1045										
1046		Total General Plant			5,289,404	3,046,629	1,348,298	8,478	568,812	317,188
1047										
1048		TOTAL RESERVE FOR DEPRECIATION			216,905,276	129,332,607	57,732,877	284,599	19,699,188	9,856,005

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF OTHER RATE BASE

Customer

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Rate Base Additions:								
2									
3	Materials and Supplies - KY Direct	7.2	Allocated O&M Expenses - Cust	(1,810)	(1,440)	(355)	(1)	(9)	(5)
4	Materials and Supplies - KY Mid-States GO	7.2	Allocated O&M Expenses - Cust	33,722	26,830	6,624	12	160	96
5	Materials and Supplies - Shared Services GO	7.2	Allocated O&M Expenses - Cust	875	697	172	0	4	2
6	Materials and Supplies - Shared Services CS	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
7	Gas Storage Inventory	99.0	-	0	-	-	-	-	-
8	Prepayments - KY Direct	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
9	Prepayments - KY Mid-States GO	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
10	Prepayments - Shared Services GO	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
11	Prepayments - Shared Services CS	7.2	Allocated O&M Expenses - Cust	0	-	-	-	-	-
12	Cash Working Capital	7.2	Allocated O&M Expenses - Cust	(134,880)	(107,312)	(26,495)	(47)	(641)	(384)
13	Regulatory Assets	7.2	Allocated O&M Expenses - Cust	(228,163)	(181,530)	(44,819)	(80)	(1,085)	(650)
14									
15	Total Rate Base Additions			(330,255)	(262,755)	(64,873)	(116)	(1,570)	(940)
16									
17									
18	Rate Base Deductions:								
19									
20	Customer Advances - KY Direct	2.0	Bills	(736,136)	(653,437)	(81,894)	(36)	(480)	(289)
21	Customer Advances - KY Mid-States GO	2.0	Bills	0	-	-	-	-	-
22	Customer Advances - Shared Services GO	2.0	Bills	0	-	-	-	-	-
23	Customer Advances - Shared Services CS	2.0	Bills	0	-	-	-	-	-
24	ADIT - KY Direct (Div 009)	9.2	Allocated Net Plant - Cust	(31,213,046)	(25,450,971)	(5,536,223)	(9,997)	(134,736)	(81,118)
25	ADIT - Shared Services GO (Div 002)	9.2	Allocated Net Plant - Cust	(2,512,364)	(2,048,570)	(445,615)	(805)	(10,845)	(6,529)
26	ADIT - Shared Services CS (Div 012)	9.2	Allocated Net Plant - Cust	(162,395)	(132,416)	(28,804)	(52)	(701)	(422)
27	ADIT - KY Mid-States GO (Div 091)	9.2	Allocated Net Plant - Cust	(60,942)	(49,692)	(10,809)	(20)	(263)	(158)
28	Change in Net Operating Loss Carryforward	9.2	Allocated Net Plant - Cust	(1,918,473)	(1,564,314)	(340,277)	(614)	(8,281)	(4,986)
29									
30	Total Rate Base Deductions			(36,603,357)	(29,899,401)	(6,443,623)	(11,523)	(155,307)	(93,503)
31									
32									
33	TOTAL OTHER RB - CUSTOMER			(36,933,611)	(30,162,156)	(6,508,496)	(11,639)	(156,877)	(94,443)
34									
35	Interest on Customer Deposits	2.0	Bills	0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF OTHER RATE BASE

Demand

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
35	Rate Base Additions:								
36									
37	Materials and Supplies - KY Direct	7.4	Allocated O&M Expenses - Demand	(3,782)	(2,042)	(1,260)	-	(480)	-
38	Materials and Supplies - KY Mid-States GO	7.4	Allocated O&M Expenses - Demand	70,483	38,057	23,487	-	8,938	-
39	Materials and Supplies - Shared Services GO	7.4	Allocated O&M Expenses - Demand	1,830	988	610	-	232	-
40	Materials and Supplies - Shared Services CS	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
41	Gas Storage Inventory	99.0	-	0	-	-	-	-	-
42	Prepayments - KY Direct	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
43	Prepayments - KY Mid-States GO	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
44	Prepayments - Shared Services GO	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
45	Prepayments - Shared Services CS	7.4	Allocated O&M Expenses - Demand	0	-	-	-	-	-
46	Cash Working Capital	7.4	Allocated O&M Expenses - Demand	(281,910)	(152,218)	(93,941)	-	(35,751)	-
47	Regulatory Assets	7.4	Allocated O&M Expenses - Demand	(476,880)	(257,493)	(158,910)	-	(60,477)	-
48									
49	Total Rate Base Additions			(690,260)	(372,708)	(230,014)	0	(87,538)	0
50									
51									
52	Rate Base Deductions:								
53									
54	Customer Advances - KY Direct	99.0	-	0	-	-	-	-	-
55	Customer Advances - KY Mid-States GO	99.0	-	0	-	-	-	-	-
56	Customer Advances - Shared Services GO	99.0	-	0	-	-	-	-	-
57	Customer Advances - Shared Services CS	99.0	-	0	-	-	-	-	-
58	ADIT - KY Direct (Div 009)	9.4	Allocated Net Plant - Demand	(39,300,119)	(21,220,228)	(13,095,922)	-	(4,983,969)	-
59	ADIT - Shared Services GO (Div 002)	9.4	Allocated Net Plant - Demand	(3,163,300)	(1,708,034)	(1,054,102)	-	(401,164)	-
60	ADIT - Shared Services CS (Div 012)	9.4	Allocated Net Plant - Demand	(204,470)	(110,404)	(68,135)	-	(25,931)	-
61	ADIT - KY Mid-States GO (Div 091)	9.4	Allocated Net Plant - Demand	(76,732)	(41,432)	(25,569)	-	(9,731)	-
62	Change in Net Operating Loss Carryforward	9.4	Allocated Net Plant - Demand	(2,415,536)	(1,304,276)	(804,925)	-	(306,334)	-
63									
64	Total Rate Base Deductions			(45,160,157)	(24,384,375)	(15,048,653)	-	(5,727,129)	-
65									
66									
67	TOTAL OTHER RB - DEMAND			(45,850,417)	(24,757,083)	(15,278,668)	-	(5,814,666)	-
68									
69	Interest on Customer Deposits	3.0	Peak Day	0	-	-	-	-	-

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ALLOCATION OF OTHER RATE BASE

Commodity

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
69	Rate Base Additions:								
70									
71	Materials and Supplies - KY Direct	7.6	Allocated O&M Expenses - Comm	(23,918)	(13,071)	(9,393)	(222)	(590)	(642)
72	Materials and Supplies - KY Mid-States GO	7.6	Allocated O&M Expenses - Comm	445,727	243,588	175,047	4,130	10,996	11,966
73	Materials and Supplies - Shared Services GO	7.6	Allocated O&M Expenses - Comm	11,571	6,324	4,544	107	285	311
74	Materials and Supplies - Shared Services CS	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
75	Gas Storage Inventory	1.0	Mcf	9,182,907	2,698,711	1,939,383	57,760	2,147,889	2,339,165
76	Prepayments - KY Direct	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
77	Prepayments - KY Mid-States GO	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
78	Prepayments - Shared Services GO	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
79	Prepayments - Shared Services CS	7.6	Allocated O&M Expenses - Comm	0	-	-	-	-	-
80	Cash Working Capital	7.6	Allocated O&M Expenses - Comm	(1,782,776)	(974,280)	(700,136)	(16,517)	(43,981)	(47,862)
81	Regulatory Assets	7.6	Allocated O&M Expenses - Comm	(3,015,748)	(1,648,094)	(1,184,352)	(27,940)	(74,398)	(80,963)
82									
83	Total Rate Base Additions			4,817,764	313,177	225,092	17,318	2,040,201	2,221,974
84									
85									
86	Rate Base Deductions:								
87									
88	Customer Advances - KY Direct	99.0	-	0	-	-	-	-	-
89	Customer Advances - KY Mid-States GO	99.0	-	0	-	-	-	-	-
90	Customer Advances - Shared Services GO	99.0	-	0	-	-	-	-	-
91	Customer Advances - Shared Services CS	99.0	-	0	-	-	-	-	-
92	ADIT - KY Direct (Div 009)	9.6	Allocated Net Plant - Comm	(24,100,745)	(7,258,217)	(5,170,556)	(149,782)	(5,523,392)	(5,998,798)
93	ADIT - Shared Services GO (Div 002)	9.6	Allocated Net Plant - Comm	(1,939,889)	(584,220)	(416,182)	(12,056)	(444,582)	(482,848)
94	ADIT - Shared Services CS (Div 012)	9.6	Allocated Net Plant - Comm	(125,391)	(37,763)	(26,901)	(779)	(28,737)	(31,210)
95	ADIT - KY Mid-States GO (Div 091)	9.6	Allocated Net Plant - Comm	(47,056)	(14,171)	(10,095)	(292)	(10,784)	(11,712)
96	Change in Net Operating Loss Carryforward	9.6	Allocated Net Plant - Comm	(1,481,324)	(446,118)	(317,802)	(9,206)	(339,489)	(368,709)
97									
98	Total Rate Base Deductions			(27,694,405)	(8,340,490)	(5,941,537)	(172,116)	(6,346,984)	(6,893,278)
99									
100									
101	TOTAL OTHER RB - COMMODITY			(22,876,641)	(8,027,312)	(5,716,445)	(154,797)	(4,306,783)	(4,671,304)
102									
103	Interest on Customer Deposits	1.0	Mcf	0	-	-	-	-	-

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ALLOCATION OF OTHER RATE BASE

Total Other Rate Base

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
103	Rate Base Additions:								
104									
105	Materials and Supplies - KY Direct			(29,510)	(16,553)	(11,009)	(222)	(1,078)	(647)
106	Materials and Supplies - KY Mid-States GO			549,932	308,476	205,158	4,141	20,095	12,062
107	Materials and Supplies - Shared Services GO			14,276	8,008	5,326	108	522	313
108	Materials and Supplies - Shared Services CS			0	-	-	-	-	-
109	Gas Storage Inventory			9,182,907	2,698,711	1,939,383	57,760	2,147,889	2,339,165
110	Prepayments - KY Direct			0	-	-	-	-	-
111	Prepayments - KY Mid-States GO			0	-	-	-	-	-
112	Prepayments - Shared Services GO			0	-	-	-	-	-
113	Prepayments - Shared Services CS			0	-	-	-	-	-
114	Cash Working Capital			(2,199,566)	(1,233,811)	(820,572)	(16,564)	(80,374)	(48,246)
115	Regulatory Assets			(3,720,791)	(2,087,117)	(1,388,081)	(28,020)	(135,960)	(81,613)
116									
117	Total Rate Base Additions			3,797,249	(322,286)	(69,795)	17,202	1,951,093	2,221,034
118									
119									
120	Rate Base Deductions:								
121									
122	Customer Advances - KY Direct			(736,136)	(653,437)	(81,894)	(36)	(480)	(289)
123	Customer Advances - KY Mid-States GO			0	-	-	-	-	-
124	Customer Advances - Shared Services GO			0	-	-	-	-	-
125	Customer Advances - Shared Services CS			0	-	-	-	-	-
126	ADIT - KY Direct (Div 009)			(94,613,910)	(53,929,417)	(23,802,700)	(159,779)	(10,642,097)	(6,079,917)
127	ADIT - Shared Services GO (Div 002)			(7,615,553)	(4,340,824)	(1,915,899)	(12,861)	(856,591)	(489,378)
128	ADIT - Shared Services CS (Div 012)			(492,256)	(280,583)	(123,840)	(831)	(55,369)	(31,633)
129	ADIT - KY Mid-States GO (Div 091)			(184,730)	(105,295)	(46,474)	(312)	(20,778)	(11,871)
130	Change in Net Operating Loss Carryforward			(5,815,333)	(3,314,708)	(1,463,005)	(9,821)	(654,104)	(373,695)
131									
132	Total Rate Base Deductions			(109,457,919)	(62,624,265)	(27,433,814)	(183,639)	(12,229,419)	(6,986,782)
133									
134									
135	TOTAL OTHER RB			(105,660,670)	(62,946,551)	(27,503,608)	(166,436)	(10,278,326)	(4,765,747)
136									
137	Interest on Customer Deposits			0	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
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ALLOCATION OF O&M EXPENSES

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Production & Gathering:								
2		Operation								
3	7500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
4	7510	Production Maps & Records	99.0	-	0	-	-	-	-	-
5	7530	Field Lines Expenses	99.0	-	0	-	-	-	-	-
6	7540	Field Compressor Station Expense	99.0	-	0	-	-	-	-	-
7	7550	Field Compressor Sta. Fuel & Pwr.	99.0	-	0	-	-	-	-	-
8	7560	Field Meas. & Regul. Station Exp	99.0	-	0	-	-	-	-	-
9	7570	Purification Expense	99.0	-	0	-	-	-	-	-
10	7590	Other Expenses	99.0	-	0	-	-	-	-	-
11		Maintenance								
12	7610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
13	7620	Structures and Improvements	99.0	-	0	-	-	-	-	-
14	7640	Field Line Maintenance	99.0	-	0	-	-	-	-	-
15	7650	Compressor Station Equip. Maint.	99.0	-	0	-	-	-	-	-
16	7660	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
17	7670	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
18	7680	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
19	7690	Gas Processed By Others	99.0	-	0	-	-	-	-	-
20		Total Production & Gathering			0	0	0	0	0	0
21										
22		Other Gas Supply Expenses:								
23		Operation								
24	8001	Intercompany Gas Well-head Purchases	99.0	-	0	-	-	-	-	-
25	8010	Natural gas field line purchases	99.0	-	0	-	-	-	-	-
26	8040	Natural gas city gate purchases	99.0	-	0	-	-	-	-	-
27	8050	Transmission-Operation supervision and engineering	99.0	-	0	-	-	-	-	-
28	8051	Other Gas Purchases / Gas Cost Adjustments	99.0	-	0	-	-	-	-	-
29	8052	PGA for Commercial	99.0	-	0	-	-	-	-	-
30	8053	PGA for Industrial	99.0	-	0	-	-	-	-	-
31	8054	PGA for Public Authority	99.0	-	0	-	-	-	-	-
32	8058	Unbilled PGA Cost	99.0	-	0	-	-	-	-	-
33	8059	PGA Offset to Unrecovered Gas Cost	99.0	-	0	-	-	-	-	-
34	8060	Exchange gas	99.0	-	0	-	-	-	-	-
35	8081	Gas withdrawn from storage-Debit	99.0	-	0	-	-	-	-	-
36	8082	Gas delivered to storage-Credit	99.0	-	0	-	-	-	-	-
37	8120	Gas used for other utility operations-Credit	99.0	-	0	-	-	-	-	-
38	8580	Transmission and compression of gas by others	99.0	-	0	-	-	-	-	-
39		Maintenance								
40	8350	Maint. Of Purch. Gas Meas. Sta.	99.0	-	0	-	-	-	-	-
41		Total Other Gas Supply Expenses			0	0	0	0	0	0
42										
43		Underground Storage:								
44		Operation								
45	8140	Storage-Operation supervision and engineering	99.0	-	0	-	-	-	-	-
46	8160	Wells expenses	99.0	-	0	-	-	-	-	-
47	8170	Lines expenses	99.0	-	0	-	-	-	-	-
48	8180	Compressor station expenses	99.0	-	0	-	-	-	-	-
49	8190	Compressor station fuel and power	99.0	-	0	-	-	-	-	-
50	8200	Storage-Measuring and regulating station expenses	99.0	-	0	-	-	-	-	-
51	8210	Storage-Purification expenses	99.0	-	0	-	-	-	-	-
52	8240	Storage-Other expenses	99.0	-	0	-	-	-	-	-
53	8250	Storage well royalties	99.0	-	0	-	-	-	-	-
54	8260	Rents	99.0	-	0	-	-	-	-	-
55		Maintenance								
56	8300	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
57	8310	Structures and Improvements	99.0	-	0	-	-	-	-	-
58	8320	Reservoirs & Wells Maintenance	99.0	-	0	-	-	-	-	-
59	8330	Line Maintenance	99.0	-	0	-	-	-	-	-
60	8340	Compressor Station Equip Maint	99.0	-	0	-	-	-	-	-
61	8350	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
62	8360	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
63	8410	Other storage expenses-Operation labor and expenses	99.0	-	0	-	-	-	-	-
64		Total Underground Storage Expense			0	0	0	0	0	0
65										
66		Transmission:								
67		Operation								
68	8500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
69	8510	System Control & Load Dispatching	99.0	-	0	-	-	-	-	-
70	8520	Communication Systems Expense	99.0	-	0	-	-	-	-	-
71	8530	Compressor Station Labor Expense	99.0	-	0	-	-	-	-	-
72	8540	Compressor Station Fuel Gas	99.0	-	0	-	-	-	-	-
73	8550	Compressor Station Fuel & Power	99.0	-	0	-	-	-	-	-
74	8560	Mains Expense	99.0	-	0	-	-	-	-	-
75	8570	Meas. & Regul. Station Expenses	99.0	-	0	-	-	-	-	-
76	8580	LDC Payment	99.0	-	0	-	-	-	-	-
77	8580	LDC Payment - A&G	99.0	-	0	-	-	-	-	-
78	8590	Other Expenses	99.0	-	0	-	-	-	-	-
79	8600	Rents	99.0	-	0	-	-	-	-	-
80		Maintenance								
81	8610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
82	8620	Structures and Improvements	99.0	-	0	-	-	-	-	-
83	8630	Mains	99.0	-	0	-	-	-	-	-
84	8640	Compressor Station Equip Maint	99.0	-	0	-	-	-	-	-
85	8650	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
86	8660	Communication Equipment Maintenance	99.0	-	0	-	-	-	-	-
87	8670	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
88		Total Transmission Expense			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF O&M EXPENSES										
89										
90		Distribution:								
91		Operation								
92	8700	Supervision and Engineering	10.2	Composite of Accts. 871-879 & 886-893 - Cust	211,070	146,866	60,036	184	2,486	1,497
93	8710	Distribution Load Dispatching	99.0	-	0	-	-	-	-	-
94	8711	Odorization	99.0	-	0	-	-	-	-	-
94	Accts. 376 & 3	Compressor Station Labor & Expenses	11.2	Composite of Accts. 376 & 380 - Cust	0	-	-	-	-	-
95	8740	Mains & Services	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
96	8750	Measuring and Regulating Station Exp. - Gen	11.2	Composite of Accts. 376 & 380 - Cust	0	-	-	-	-	-
97	8760	Measuring and Regulating Station Exp. - Ind.	2.2	Non-Residential Bills	523	-	518	0	3	2
98	8770	Measuring and Regulating Sta. Exp. - City Gate	11.2	Composite of Accts. 376 & 380 - Cust	0	-	-	-	-	-
99	8780	Meters and House Regulator Expense	13.2	Composite of Accts. 381-383 - Cust	938,471	653,413	266,517	821	11,060	6,659
100	8790	Customer Installations Expense	2.0	Bills	257	228	29	0	0	0
101	8800	Other Expense	10.2	Composite of Accts. 871-879 & 886-893 - Cust	304	212	87	0	4	2
102	8810	Rents	10.2	Composite of Accts. 871-879 & 886-893 - Cust	7,397	5,147	2,104	6	87	52
103		Maintenance								
104	8850	Maintenance Supervision and Engineering	10.2	Composite of Accts. 871-879 & 886-893 - Cust	0	-	-	-	-	-
105	8860	Maintenance of Structures and Improvements	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
106	8870	Maintenance of Mains	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
107	8890	Maintenance of compressor station equipment	99.0	-	0	-	-	-	-	-
108	8900	Maint. of Measuring and Regulating Station Equip. - General	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
109	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	2.2	Non-Residential Bills	135	-	133	0	1	0
110	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	12.2	Composite of Accts. 374-379 - Cust	0	-	-	-	-	-
111	8930	Maintenance of Services	14.2	Account 380 - Cust	0	-	-	-	-	-
112	8940	Maintenance of Meters and House Regulators	13.2	Composite of Accts. 381-383 - Cust	0	-	-	-	-	-
113	8950	Maintenance of Other Equipment	10.2	Composite of Accts. 871-879 & 886-893 - Cust	0	-	-	-	-	-
114		Total Distribution			1,158,157	805,867	329,424	1,012	13,641	8,213
115										
116		Customer Accounts:								
117	9010	Supervision	2.0	Bills	0	-	-	-	-	-
118	9020	Meter Reading Expense	2.0	Bills	735,288	652,684	81,800	36	480	289
119	9030	Customer Records and Collection Expenses	2.0	Bills	1,067,803	947,844	118,792	52	697	419
120	9040	Uncollectible Accounts	8.0	Customer Deposit Balances	731,532	496,144	235,187	-	200	-
121	9050	Miscellaneous Customer Accounts Expenses	2.0	Bills	0	-	-	-	-	-
122		Total Customer Accounts			2,534,624	2,096,673	435,779	87	1,376	708
123										
124		Customer Service and Information:								
125	9070	Supervision	2.0	Bills	0	-	-	-	-	-
126	9080	Customer Assistance Expenses	2.0	Bills	0	-	-	-	-	-
127	9090	Informational and Instructional Advertising Expenses	2.0	Bills	214,461	190,368	23,859	10	140	84
128	9100	Miscellaneous Customer Service and Informational Expenses	2.0	Bills	0	-	-	-	-	-
129		Total Customer Service and Information			214,461	190,368	23,859	10	140	84
130										
131		Sales:								
132	9110	Supervision	2.0	Bills	158,549	140,737	17,638	8	103	62
133	9120	Demonstrating and Selling Expenses	2.0	Bills	77,078	68,419	8,575	4	50	30
134	9130	Advertising Expenses	2.0	Bills	36,821	32,685	4,096	2	24	14
135	9160	Miscellaneous Sales Expenses	2.0	Bills	(188,721)	(167,520)	(20,995)	(9)	(123)	(74)
136		Total Sales			83,728	74,321	9,315	4	55	33
137										
138		Administrative & General:								
139		Operation								
140	9200	Administrative and General Salaries	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	0	-	-	-	-	-
141	9210	Office Supplies and Expenses	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	12,576	9,978	2,469	6	77	46
142	9220	Administrative Expenses Transferred - Customer Support	2.0	Bills	0	-	-	-	-	-
143	9220	Administrative Expenses Transferred - General	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	3,323,172	2,636,587	652,498	1,509	20,335	12,243
144	9230	Outside Services Employed	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	12,744	10,111	2,502	6	78	47
145	9240	Property Insurance	9.2	Allocated Net Plant - Cust	0	-	-	-	-	-
146	9250	Injuries and Damages	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	4,235	3,360	831	2	26	16
147	9260	Employee Pensions and Benefits	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	158,911	126,079	31,202	72	972	585
148	9270	Franchise Requirements	2.0	Bills	635	564	71	0	0	0
149	9280	Regulatory Commission Expenses	2.0	Bills	165,392	146,811	18,400	8	108	65
150	930.1	General Advertising Expenses	2.0	Bills	0	-	-	-	-	-
151	930.2	Miscellaneous General Expense	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	4,445	3,526	873	2	27	16
152	ADJ	Adjustments	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	(255,697)	(202,868)	(50,205)	(116)	(1,565)	(942)
153		Maintenance								
154	9320	Maintenance of General Plant	17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	0	-	-	-	-	-
155		Total A&G			3,426,413	2,734,148	658,640	1,488	20,059	12,077
156										
157		TOTAL O&M EXPENSE - CUSTOMER			7,417,382	5,901,377	1,457,017	2,602	35,271	21,115

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
158		Production & Gathering:								
159		Operation								
160	7500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
161	7510	Production Maps & Records	99.0	-	0	-	-	-	-	-
162	7530	Field Lines Expenses	99.0	-	0	-	-	-	-	-
163	7540	Field Compressor Station Expense	99.0	-	0	-	-	-	-	-
164	7550	Field Compressor Sta. Fuel & Pwr.	99.0	-	0	-	-	-	-	-
165	7560	Field Meas. & Regul. Station Exp	99.0	-	0	-	-	-	-	-
166	7570	Purification Expense	99.0	-	0	-	-	-	-	-
167	7590	Other Expenses	99.0	-	0	-	-	-	-	-
168		Maintenance								
169	7610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
170	7620	Structures and Improvements	99.0	-	0	-	-	-	-	-
171	7640	Field Line Maintenance	99.0	-	0	-	-	-	-	-
172	7650	Compressor Station Equip. Maint.	99.0	-	0	-	-	-	-	-
173	7660	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
174	7670	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
175	7680	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
176	7690	Gas Processed By Others	99.0	-	0	-	-	-	-	-
177		Total Production & Gathering			0	0	0	0	0	0
178										
179		Other Gas Supply Expenses:								
180		Operation								
181	8001	Intercompany Gas Well-head Purchases	99.0	-	0	-	-	-	-	-
182	8010	Natural gas field line purchases	99.0	-	0	-	-	-	-	-
183	8040	Natural gas city gate purchases	99.0	-	0	-	-	-	-	-
184	8050	Transmission-Operation supervision and engineering	99.0	-	0	-	-	-	-	-
185	8051	Other Gas Purchases / Gas Cost Adjustments	99.0	-	0	-	-	-	-	-
186	8052	PGA for Commercial	99.0	-	0	-	-	-	-	-
187	8053	PGA for Industrial	99.0	-	0	-	-	-	-	-
188	8054	PGA for Public Authority	99.0	-	0	-	-	-	-	-
189	8058	Unbilled PGA Cost	99.0	-	0	-	-	-	-	-
190	8059	PGA Offset to Unrecovered Gas Cost	99.0	-	0	-	-	-	-	-
191	8060	Exchange gas	99.0	-	0	-	-	-	-	-
192	8081	Gas withdrawn from storage-Debit	99.0	-	0	-	-	-	-	-
193	8082	Gas delivered to storage-Credit	99.0	-	0	-	-	-	-	-
194	8120	Gas used for other utility operations-Credit	99.0	-	0	-	-	-	-	-
195	8580	Transmission and compression of gas by others	99.0	-	0	-	-	-	-	-
196		Maintenance								
197	8350	Maint. Of Purch. Gas Meas. Sta.	99.0	-	0	-	-	-	-	-
198		Total Other Gas Supply Expenses			0	0	0	0	0	0
199										
200		Underground Storage:								
201		Operation								
202	8140	Storage-Operation supervision and engineering	3.0	Peak Day	0	-	-	-	-	-
203	8160	Wells expenses	3.0	Peak Day	17,582	9,493	5,859	-	2,230	-
204	8170	Lines expenses	3.0	Peak Day	11,391	6,150	3,796	-	1,445	-
205	8180	Compressor station expenses	3.0	Peak Day	22,388	12,089	7,460	-	2,839	-
206	8190	Compressor station fuel and power	3.0	Peak Day	0	-	-	-	-	-
207	8200	Storage-Measuring and regulating station expenses	3.0	Peak Day	4,768	2,575	1,589	-	605	-
208	8210	Storage-Purification expenses	3.0	Peak Day	41,970	22,662	13,986	-	5,323	-
209	8240	Storage-Other expenses	3.0	Peak Day	0	-	-	-	-	-
210	8250	Storage well royalties	3.0	Peak Day	5,241	2,830	1,746	-	665	-
211	8260	Rents	3.0	Peak Day	0	-	-	-	-	-
212		Maintenance								
213	8300	Maint. Sup., & Eng.	3.0	Peak Day	0	-	-	-	-	-
214	8310	Structures and Improvements	3.0	Peak Day	0	-	-	-	-	-
215	8320	Reservoirs & Wells Maintenance	3.0	Peak Day	0	-	-	-	-	-
216	8330	Line Maintenance	3.0	Peak Day	0	-	-	-	-	-
217	8340	Compressor Station Equip Maint	3.0	Peak Day	23,208	12,531	7,734	-	2,943	-
218	8350	Meas. & Regul. Station Equip Maint	3.0	Peak Day	0	-	-	-	-	-
219	8360	Purification Equipment Maintenance	3.0	Peak Day	0	-	-	-	-	-
220	8410	Other storage expenses-Operation labor and expenses	3.0	Peak Day	116,621	62,970	38,862	-	14,790	-
221		Total Underground Storage Expense			243,169	131,300	81,031	0	30,838	0
222										
223		Transmission:								
224		Operation								
225	8500	Op., Sup., & Eng.	3.0	Peak Day	0	-	-	-	-	-
226	8510	System Control & Load Dispatching	3.0	Peak Day	0	-	-	-	-	-
227	8520	Communication Systems Expense	3.0	Peak Day	0	-	-	-	-	-
228	8530	Compressor Station Labor Expense	3.0	Peak Day	0	-	-	-	-	-
229	8540	Compressor Station Fuel Gas	3.0	Peak Day	0	-	-	-	-	-
230	8550	Compressor Station Fuel & Power	3.0	Peak Day	488	264	163	-	62	-
231	8560	Mains Expense	3.0	Peak Day	145,499	78,563	48,484	-	18,452	-
232	8570	Meas. & Regul. Station Expenses	3.0	Peak Day	11,936	6,445	3,977	-	1,514	-
233	8580	LDC Payment	3.0	Peak Day	0	-	-	-	-	-
234	8580	LDC Payment - A&G	3.0	Peak Day	0	-	-	-	-	-
235	8590	Other Expenses	3.0	Peak Day	0	-	-	-	-	-
236	8600	Rents	3.0	Peak Day	0	-	-	-	-	-
237		Maintenance								
238	8610	Maint. Sup., & Eng.	3.0	Peak Day	0	-	-	-	-	-
239	8620	Structures and Improvements	3.0	Peak Day	0	-	-	-	-	-
240	8630	Mains	3.0	Peak Day	22,915	12,373	7,636	-	2,906	-
241	8640	Compressor Station Equip Maint	3.0	Peak Day	0	-	-	-	-	-
242	8650	Meas. & Regul. Station Equip Maint	3.0	Peak Day	0	-	-	-	-	-
243	8660	Communication Equipment Maintenance	3.0	Peak Day	0	-	-	-	-	-
244	8670	Other Equipment Maintenance	3.0	Peak Day	0	-	-	-	-	-
245		Total Transmission Expense			180,838	97,644	60,261	0	22,934	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF O&M EXPENSES										
246										
247		Distribution:								
248		Operation								
249	8700	Supervision and Engineering	10.4	Composite of Accts. 871-879 & 886-893 - Demand	1,153,074	622,606	384,237	-	146,231	-
250	8710	Distribution Load Dispatching	99.0	-	0	-	-	-	-	-
251	8711	Odorization	99.0	-	0	-	-	-	-	-
251	8720	Compressor Station Labor & Expenses	11.4	Composite of Accts. 376 & 380 - Demand	0	-	-	-	-	-
252	8740	Mains & Services	12.4	Composite of Accts. 374-379 - Demand	4,198,850	2,267,183	1,399,177	-	532,490	-
253	8750	Measuring and Regulating Station Exp. - Gen	12.4	Composite of Accts. 374-379 - Demand	840,349	453,749	280,028	-	106,572	-
254	8760	Measuring and Regulating Station Exp. - Ind.	99.0	-	0	-	-	-	-	-
255	8770	Measuring and Regulating Sta. Exp. - City Gate	12.4	Composite of Accts. 374-379 - Demand	3,387	1,829	1,129	-	430	-
256	8780	Meters and House Regulator Expense	13.4	Composite of Accts. 381-383 - Demand	0	-	-	-	-	-
257	8790	Customer Installations Expense	99.0	-	0	-	-	-	-	-
258	8800	Other Expense	10.4	Composite of Accts. 871-879 & 886-893 - Demand	1,662	897	554	-	211	-
259	8810	Rents	10.4	Composite of Accts. 871-879 & 886-893 - Demand	40,410	21,820	13,466	-	5,125	-
260		Maintenance								
261	8850	Maintenance Supervision and Engineering	10.4	Composite of Accts. 871-879 & 886-893 - Demand	0	-	-	-	-	-
262	8860	Maintenance of Structures and Improvements	12.4	Composite of Accts. 374-379 - Demand	0	-	-	-	-	-
263	8870	Maintenance of Mains	12.4	Composite of Accts. 374-379 - Demand	89,174	48,150	29,715	-	11,309	-
264	8890	Maintenance of compressor station equipment	99.0	-	0	-	-	-	-	-
265	8900	Maint. of Measuring and Regulating Station Equip. - General	12.4	Composite of Accts. 374-379 - Demand	0	-	-	-	-	-
266	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	99.0	-	0	-	-	-	-	-
267	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	12.4	Composite of Accts. 374-379 - Demand	110	59	37	-	14	-
268	8930	Maintenance of Services	14.4	Account 380 - Demand	0	-	-	-	-	-
269	8940	Maintenance of Meters and House Regulators	13.4	Composite of Accts. 381-383 - Demand	0	-	-	-	-	-
270	8950	Maintenance of Other Equipment	10.4	Composite of Accts. 871-879 & 886-893 - Demand	0	-	-	-	-	-
271		Total Distribution			6,327,016	3,416,293	2,108,342	0	802,381	0
272										
273		Customer Accounts:								
274	9010	Supervision	99.0	-	0	-	-	-	-	-
275	9020	Meter Reading Expense	99.0	-	0	-	-	-	-	-
276	9030	Customer Records and Collection Expenses	99.0	-	0	-	-	-	-	-
277	9040	Uncollectible Accounts	99.0	-	0	-	-	-	-	-
278	9050	Miscellaneous Customer Accounts Expenses	99.0	-	0	-	-	-	-	-
279		Total Customer Accounts			0	-	-	-	-	-
280										
281		Customer Service and Information:								
282	9070	Supervision	99.0	-	0	-	-	-	-	-
283	9080	Customer Assistance Expenses	99.0	-	0	-	-	-	-	-
284	9090	Informational and Instructional Advertising Expenses	99.0	-	0	-	-	-	-	-
285	9100	Miscellaneous Customer Service and Informational Expenses	99.0	-	0	-	-	-	-	-
286		Total Customer Service and Information			0	-	-	-	-	-
287										
288		Sales:								
289	9110	Supervision	99.0	-	0	-	-	-	-	-
290	9120	Demonstrating and Selling Expenses	99.0	-	0	-	-	-	-	-
291	9130	Advertising Expenses	99.0	-	0	-	-	-	-	-
292	9160	Miscellaneous Sales Expenses	99.0	-	0	-	-	-	-	-
293		Total Sales			0	-	-	-	-	-
294										
295		Administrative & General:								
296		Operation								
297	9200	Administrative and General Salaries	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	0	-	-	-	-	-
298	9210	Office Supplies and Expenses	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	33,758	18,228	11,249	-	4,281	-
299	9220	Administrative Expenses Transferred - Customer Support	99.0	-	0	-	-	-	-	-
300	9220	Administrative Expenses Transferred - General	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	8,920,466	4,816,635	2,972,554	-	1,131,277	-
301	9230	Outside Services Employed	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	34,209	18,472	11,400	-	4,338	-
302	9240	Property Insurance	9.4	Allocated Net Plant - Demand	0	-	-	-	-	-
303	9250	Injuries and Damages	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	11,367	6,138	3,788	-	1,442	-
304	9260	Employee Pensions and Benefits	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	426,567	230,327	142,144	-	54,097	-
305	9270	Franchise Requirements	99.0	-	0	-	-	-	-	-
306	9280	Regulatory Commission Expenses	99.0	-	0	-	-	-	-	-
307	930.1	General Advertising Expenses	99.0	-	0	-	-	-	-	-
308	930.2	Miscellaneous General Expense	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	11,931	6,442	3,976	-	1,513	-
309	ADJ	Adjustments	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	(686,372)	(370,609)	(228,719)	-	(87,044)	-
310		Maintenance								
311	9320	Maintenance of General Plant	17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	0	-	-	-	-	-
312		Total A&G			8,751,926	4,725,631	2,916,392	0	1,109,903	0
313										
314		TOTAL O&M EXPENSE - DEMAND			15,502,949	8,370,868	5,166,025	0	1,966,056	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
315		Production & Gathering:								
316		Operation								
317	7500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
318	7510	Production Maps & Records	99.0	-	0	-	-	-	-	-
319	7530	Field Lines Expenses	99.0	-	0	-	-	-	-	-
320	7540	Field Compressor Station Expense	99.0	-	0	-	-	-	-	-
321	7550	Field Compressor Sta. Fuel & Pwr.	99.0	-	0	-	-	-	-	-
322	7560	Field Meas. & Regul. Station Exp	18.4	Gas Costs	0	-	-	-	-	-
323	7570	Purification Expense	99.0	-	0	-	-	-	-	-
324	7590	Other Expenses	99.0	-	0	-	-	-	-	-
325		Maintenance								
326	7610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
327	7620	Structures and Improvements	99.0	-	0	-	-	-	-	-
328	7640	Field Line Maintenance	99.0	-	0	-	-	-	-	-
329	7650	Compressor Station Equip. Maint.	99.0	-	0	-	-	-	-	-
330	7660	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
331	7670	Purification Equipment Maintenance	99.0	-	0	-	-	-	-	-
332	7680	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
333	7690	Gas Processed By Others	99.0	-	0	-	-	-	-	-
334		Total Production & Gathering			0	0	0	0	0	0
335										
336		Other Gas Supply Expenses:								
337		Operation								
338	8001	Intercompany Gas Well-head Purchases	18.4	Gas Costs	0	-	-	-	-	-
339	8010	Natural gas field line purchases	18.4	Gas Costs	115,617	66,622	47,883	1,112	-	-
340	8040	Natural gas city gate purchases	18.4	Gas Costs	50,226,537	28,941,994	20,801,358	483,186	-	-
341	8050	Transmission-Operation supervision and engineering	18.4	Gas Costs	(29,531)	(17,016)	(12,230)	(284)	-	-
342	8051	Other Gas Purchases / Gas Cost Adjustments	18.4	Gas Costs	53,391,020	30,765,461	22,111,930	513,629	-	-
343	8052	PGA for Commercial	18.4	Gas Costs	30,150,016	17,373,318	12,486,652	290,047	-	-
344	8053	PGA for Industrial	18.4	Gas Costs	4,872,096	2,807,444	2,017,782	46,870	-	-
345	8054	PGA for Public Authority	18.4	Gas Costs	4,999,866	2,881,068	2,070,698	48,099	-	-
346	8058	Unbilled PGA Cost	18.4	Gas Costs	(5,763,929)	(3,321,344)	(2,387,135)	(55,450)	-	-
347	8059	PGA Offset to Unrecovered Gas Cost	18.4	Gas Costs	(109,657,357)	(63,187,763)	(45,414,676)	(1,054,918)	-	-
348	8060	Exchange gas	18.4	Gas Costs	(122,035)	(70,320)	(50,541)	(1,174)	-	-
349	8081	Gas withdrawn from storage-Debit	18.4	Gas Costs	30,798,939	17,747,246	12,755,403	296,290	-	-
350	8082	Gas delivered to storage-Credit	18.4	Gas Costs	(14,414,625)	(8,306,127)	(5,969,828)	(138,671)	-	-
351	8120	Gas used for other utility operations-Credit	18.4	Gas Costs	(8,172)	(4,709)	(3,384)	(79)	-	-
352	8580	Transmission and compression of gas by others	18.4	Gas Costs	43,082,454	24,825,365	17,842,630	414,459	-	-
353		Maintenance								
354	8350	Maint. Of Purch. Gas Meas. Sta.	18.4	Gas Costs	0	-	-	-	-	-
355		Total Other Gas Supply Expenses			87,640,898	50,501,238	36,296,543	843,117	0	0
356										
357		Underground Storage:								
358		Operation								
359	8140	Storage-Operation supervision and engineering	1.5	Winter Volumes	0	-	-	-	-	-
360	8160	Wells expenses	1.5	Winter Volumes	17,582	6,679	4,408	95	3,131	3,268
361	8170	Lines expenses	1.5	Winter Volumes	11,391	4,327	2,856	62	2,029	2,117
362	8180	Compressor station expenses	1.5	Winter Volumes	22,388	8,505	5,613	121	3,987	4,161
363	8190	Compressor station fuel and power	1.5	Winter Volumes	0	-	-	-	-	-
364	8200	Storage-Measuring and regulating station expenses	1.5	Winter Volumes	4,768	1,811	1,195	26	849	886
365	8210	Storage-Purification expenses	1.5	Winter Volumes	41,970	15,945	10,523	227	7,475	7,801
366	8240	Storage-Other expenses	1.5	Winter Volumes	0	-	-	-	-	-
367	8250	Storage well royalties	1.5	Winter Volumes	5,241	1,991	1,314	28	933	974
368	8260	Rents	1.5	Winter Volumes	0	-	-	-	-	-
369		Maintenance								
370	8300	Maint. Sup., & Eng.	1.5	Winter Volumes	0	-	-	-	-	-
371	8310	Structures and Improvements	1.5	Winter Volumes	0	-	-	-	-	-
372	8320	Reservoirs & Wells Maintenance	1.5	Winter Volumes	0	-	-	-	-	-
373	8330	Line Maintenance	1.5	Winter Volumes	0	-	-	-	-	-
374	8340	Compressor Station Equip Maint	1.5	Winter Volumes	23,208	8,817	5,819	125	4,133	4,314
375	8350	Meas. & Regul. Station Equip Maint	1.5	Winter Volumes	0	-	-	-	-	-
376	8360	Purification Equipment Maintenance	1.5	Winter Volumes	0	-	-	-	-	-
377	8410	Other storage expenses-Operation labor and expenses	1.5	Winter Volumes	116,621	44,305	29,240	630	20,769	21,677
378		Total Underground Storage Expense			243,169	92,381	60,969	1,314	43,307	45,199
379										
380		Transmission:								
381		Operation								
382	8500	Op., Sup., & Eng.	99.0	-	0	-	-	-	-	-
383	8510	System Control & Load Dispatching	99.0	-	0	-	-	-	-	-
384	8520	Communication Systems Expense	99.0	-	0	-	-	-	-	-
385	8530	Compressor Station Labor Expense	99.0	-	0	-	-	-	-	-
386	8540	Compressor Station Fuel Gas	99.0	-	0	-	-	-	-	-
387	8550	Compressor Station Fuel & Power	99.0	-	0	-	-	-	-	-
388	8560	Mains Expense	99.0	-	0	-	-	-	-	-
389	8570	Meas. & Regul. Station Expenses	99.0	-	0	-	-	-	-	-
390	8580	LDC Payment	99.0	-	0	-	-	-	-	-
391	8580	LDC Payment - A&G	99.0	-	0	-	-	-	-	-
392	8590	Other Expenses	99.0	-	0	-	-	-	-	-
393	8600	Rents	99.0	-	0	-	-	-	-	-
394		Maintenance								
395	8610	Maint. Sup., & Eng.	99.0	-	0	-	-	-	-	-
396	8620	Structures and Improvements	99.0	-	0	-	-	-	-	-
397	8630	Mains	99.0	-	0	-	-	-	-	-
398	8640	Compressor Station Equip Maint	99.0	-	0	-	-	-	-	-
399	8650	Meas. & Regul. Station Equip Maint	99.0	-	0	-	-	-	-	-
400	8660	Communication Equipment Maintenance	99.0	-	0	-	-	-	-	-
401	8670	Other Equipment Maintenance	99.0	-	0	-	-	-	-	-
402		Total Transmission Expense			0	0	0	0	0	0

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF O&M EXPENSES										
403										
404		Distribution:								
405		Operation								
406	8700	Supervision and Engineering	10.6	Composite of Accts. 871-879 & 886-893 - Comm	776,562	228,219	164,006	4,885	181,638	197,814
407	8710	Distribution Load Dispatching	1.0	Mcf	(41)	(12)	(9)	(0)	(10)	(11)
408	8711	Odorization	1.0	Mcf	132,819	39,034	28,051	835	31,067	33,833
408	8720	Compressor Station Labor & Expenses	99.0	-	0	-	-	-	-	-
409	8740	Mains & Services	12.6	Composite of Accts. 374-379 - Comm	2,604,135	765,314	549,980	16,380	609,109	663,352
410	8750	Measuring and Regulating Station Exp. - Gen	12.6	Composite of Accts. 374-379 - Comm	521,186	153,168	110,072	3,278	121,906	132,762
411	8760	Measuring and Regulating Station Exp. - Ind.	99.0	-	0	-	-	-	-	-
412	8770	Measuring and Regulating Sta. Exp. - City Gate	12.6	Composite of Accts. 374-379 - Comm	2,100	617	444	13	491	535
413	8780	Meters and House Regulator Expense	99.0	-	0	-	-	-	-	-
414	8790	Customer Installations Expense	99.0	-	0	-	-	-	-	-
415	8800	Other Expense	10.6	Composite of Accts. 871-879 & 886-893 - Comm	1,119	329	236	7	262	285
416	8810	Rents	10.6	Composite of Accts. 871-879 & 886-893 - Comm	27,215	7,998	5,748	171	6,366	6,933
417		Maintenance								
418	8850	Maintenance Supervision and Engineering	10.6	Composite of Accts. 871-879 & 886-893 - Comm	0	-	-	-	-	-
419	8860	Maintenance of Structures and Improvements	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
420	8870	Maintenance of Mains	12.6	Composite of Accts. 374-379 - Comm	55,306	16,254	11,680	348	12,936	14,088
421	8890	Maintenance of compressor station equipment	1.0	Mcf	140,590	41,317	29,692	884	32,884	35,812
422	8900	Maint. of Measuring and Regulating Station Equip. - General	12.6	Composite of Accts. 374-379 - Comm	0	-	-	-	-	-
423	8910	Maint. of Measuring and Regulating Station Equip. - Industrial	5.0	Direct to Transport Interruptible	0	-	-	-	-	-
424	8920	Maint. of Measuring and Regulating Station Equip. - City Gate	12.6	Composite of Accts. 374-379 - Comm	68	20	14	0	16	17
425	8930	Maintenance of Services	14.6	Account 380 - Comm	0	-	-	-	-	-
426	8940	Maintenance of Meters and House Regulators	13.6	Composite of Accts. 381-383 - Comm	0	-	-	-	-	-
427	8950	Maintenance of Other Equipment	10.6	Composite of Accts. 871-879 & 886-893 - Comm	0	-	-	-	-	-
428		Total Distribution			4,261,059	1,252,258	899,914	26,802	996,665	1,085,421
429										
430		Customer Accounts:								
431	9010	Supervision	99.0	-	0	-	-	-	-	-
432	9020	Meter Reading Expense	99.0	-	0	-	-	-	-	-
433	9030	Customer Records and Collection Expenses	99.0	-	0	-	-	-	-	-
434	9040	Uncollectible Accounts	99.0	-	0	-	-	-	-	-
435	9050	Miscellaneous Customer Accounts Expenses	99.0	-	0	-	-	-	-	-
436		Total Customer Accounts			0	-	-	-	-	-
437										
438		Customer Service and Information:								
439	9070	Supervision	99.0	-	0	-	-	-	-	-
440	9080	Customer Assistance Expenses	99.0	-	0	-	-	-	-	-
441	9090	Informational and Instructional Advertising Expenses	99.0	-	0	-	-	-	-	-
442	9100	Miscellaneous Customer Service and Informational Expenses	99.0	-	0	-	-	-	-	-
443		Total Customer Service and Information			0	-	-	-	-	-
444										
445		Sales:								
446	9110	Supervision	99.0	-	0	-	-	-	-	-
447	9120	Demonstrating and Selling Expenses	99.0	-	0	-	-	-	-	-
448	9130	Advertising Expenses	99.0	-	0	-	-	-	-	-
449	9160	Miscellaneous Sales Expenses	99.0	-	0	-	-	-	-	-
450		Total Sales			0	-	-	-	-	-
451										
452		Administrative & General:								
453		Operation								
454	9200	Administrative and General Salaries	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	0	-	-	-	-	-
455	9210	Office Supplies and Expenses	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	22,735	6,681	4,802	143	5,318	5,791
456	9220	Administrative Expenses Transferred - Customer Support	99.0	-	0	-	-	-	-	-
457	9220	Administrative Expenses Transferred - General	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	6,007,671	1,765,559	1,268,789	37,788	1,405,199	1,530,336
458	9230	Outside Services Employed	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	23,039	6,771	4,866	145	5,389	5,869
459	9240	Property Insurance	9.6	Allocated Net Plant - Comm	0	-	-	-	-	-
460	9250	Injuries and Damages	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	7,655	2,250	1,617	48	1,791	1,950
461	9260	Employee Pensions and Benefits	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	287,281	84,427	60,672	1,807	67,195	73,179
462	9270	Franchise Requirements	99.0	-	0	-	-	-	-	-
463	9280	Regulatory Commission Expenses	99.0	-	0	-	-	-	-	-
464	930.1	General Advertising Expenses	99.0	-	0	-	-	-	-	-
465	930.2	Miscellaneous General Expense	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	8,035	2,361	1,697	51	1,879	2,047
466	ADJ	Adjustments	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	(462,252)	(135,848)	(97,625)	(2,908)	(108,121)	(117,749)
467		Maintenance								
468	9320	Maintenance of General Plant	17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	0	-	-	-	-	-
469		Total A&G			5,894,165	1,732,202	1,244,817	37,074	1,378,650	1,501,422
470										
471		TOTAL O&M EXPENSE - COMMODITY			98,039,291	53,578,078	38,502,243	908,306	2,418,621	2,632,042

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

Total O&M Expenses

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
472		Production & Gathering:								
473		Operation								
474	7500	Op., Sup., & Eng.			0	0	0	0	0	0
475	7510	Production Maps & Records			0	0	0	0	0	0
476	7530	Field Lines Expenses			0	0	0	0	0	0
477	7540	Field Compressor Station Expense			0	0	0	0	0	0
478	7550	Field Compressor Sta. Fuel & Pwr.			0	0	0	0	0	0
479	7560	Field Meas. & Regul. Station Exp			0	0	0	0	0	0
480	7570	Purification Expense			0	0	0	0	0	0
481	7590	Other Expenses			0	0	0	0	0	0
482		Maintenance								
483	7610	Maint. Sup., & Eng.			0	0	0	0	0	0
484	7620	Structures and Improvements			0	0	0	0	0	0
485	7640	Field Line Maintenance			0	0	0	0	0	0
486	7650	Compressor Station Equip. Maint.			0	0	0	0	0	0
487	7660	Meas. & Regul. Station Equip Maint			0	0	0	0	0	0
488	7670	Purification Equipment Maintenance			0	0	0	0	0	0
489	7680	Other Equipment Maintenance			0	0	0	0	0	0
490	7690	Gas Processed By Others			0	0	0	0	0	0
491		Total Production & Gathering			0	0	0	0	0	0
492										
493		Other Gas Supply Expenses:								
494		Operation								
495	8001	Intercompany Gas Well-head Purchases			0	0	0	0	0	0
496	8010	Natural gas field line purchases			115,617	66,622	47,883	1,112	0	0
497	8040	Natural gas city gate purchases			50,226,537	28,941,994	20,801,358	483,186	0	0
498	8050	Transmission-Operation supervision and engineering			(29,531)	(17,016)	(12,230)	(284)	0	0
499	8051	Other Gas Purchases / Gas Cost Adjustments			53,391,020	30,765,461	22,111,930	513,629	0	0
500	8052	PGA for Commercial			30,150,016	17,373,318	12,486,652	290,047	0	0
501	8053	PGA for Industrial			4,872,096	2,807,444	2,017,782	46,870	0	0
502	8054	PGA for Public Authority			4,999,866	2,881,068	2,070,698	48,099	0	0
503	8058	Unbilled PGA Cost			(5,763,929)	(3,321,344)	(2,387,135)	(55,450)	0	0
504	8059	PGA Offset to Unrecovered Gas Cost			(109,657,357)	(63,187,763)	(45,414,676)	(1,054,918)	0	0
505	8060	Exchange gas			(122,035)	(70,320)	(50,541)	(1,174)	0	0
506	8081	Gas withdrawn from storage-Debit			30,798,939	17,747,246	12,755,403	296,290	0	0
507	8082	Gas delivered to storage-Credit			(14,414,625)	(8,306,127)	(5,969,828)	(138,671)	0	0
508	8120	Gas used for other utility operations-Credit			(8,172)	(4,709)	(3,384)	(79)	0	0
509	8580	Transmission and compression of gas by others			43,082,454	24,825,365	17,842,630	414,459	0	0
510		Maintenance								
511	8350	Maint. Of Purch. Gas Meas. Sta.			0	0	0	0	0	0
512		Total Other Gas Supply Expenses			87,640,898	50,501,238	36,296,543	843,117	0	0
513										
514		Underground Storage:								
515		Operation								
516	8140	Storage-Operation supervision and engineering			0	0	0	0	0	0
517	8160	Wells expenses			35,164	16,173	10,267	95	5,361	3,268
518	8170	Lines expenses			22,782	10,478	6,652	62	3,473	2,117
519	8180	Compressor station expenses			44,776	20,594	13,074	121	6,826	4,161
520	8190	Compressor station fuel and power			0	0	0	0	0	0
521	8200	Storage-Measuring and regulating station expenses			9,536	4,386	2,784	26	1,454	886
522	8210	Storage-Purification expenses			83,940	38,606	24,509	227	12,797	7,801
523	8240	Storage-Other expenses			0	0	0	0	0	0
524	8250	Storage well royalties			10,482	4,821	3,060	28	1,598	974
525	8260	Rents			0	0	0	0	0	0
526		Maintenance								
527	8300	Maint. Sup., & Eng.			0	0	0	0	0	0
528	8310	Structures and Improvements			0	0	0	0	0	0
529	8320	Reservoirs & Wells Maintenance			0	0	0	0	0	0
530	8330	Line Maintenance			0	0	0	0	0	0
531	8340	Compressor Station Equip Maint			46,416	21,348	13,552	125	7,076	4,314
532	8350	Meas. & Regul. Station Equip Maint			0	0	0	0	0	0
533	8360	Purification Equipment Maintenance			0	0	0	0	0	0
534	8410	Other storage expenses-Operation labor and expenses			233,243	107,275	68,102	630	35,559	21,677
535		Total Underground Storage Expense			486,338	223,681	142,000	1,314	74,145	45,199
536										
537		Transmission:								
538		Operation								
539	8500	Op., Sup., & Eng.			0	0	0	0	0	0
540	8510	System Control & Load Dispatching			0	0	0	0	0	0
541	8520	Communication Systems Expense			0	0	0	0	0	0
542	8530	Compressor Station Labor Expense			0	0	0	0	0	0
543	8540	Compressor Station Fuel Gas			0	0	0	0	0	0
544	8550	Compressor Station Fuel & Power			488	264	163	0	62	0
545	8560	Mains Expense			145,499	78,563	48,484	0	18,452	0
546	8570	Meas. & Regul. Station Expenses			11,936	6,445	3,977	0	1,514	0
547	8580	LDC Payment			0	0	0	0	0	0
548	8580	LDC Payment - A&G			0	0	0	0	0	0
549	8590	Other Expenses			0	0	0	0	0	0
550	8600	Rents			0	0	0	0	0	0
551		Maintenance								
552	8610	Maint. Sup., & Eng.			0	0	0	0	0	0
553	8620	Structures and Improvements			0	0	0	0	0	0
554	8630	Mains			22,915	12,373	7,636	0	2,906	0
555	8640	Compressor Station Equip Maint			0	0	0	0	0	0
556	8650	Meas. & Regul. Station Equip Maint			0	0	0	0	0	0
557	8660	Communication Equipment Maintenance			0	0	0	0	0	0
558	8670	Other Equipment Maintenance			0	0	0	0	0	0
559		Total Transmission Expense			180,838	97,644	60,261	0	22,934	0

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF O&M EXPENSES

560										
561			Distribution:							
562			Operation							
563	8700		Supervision and Engineering		2,140,705	997,691	608,279	5,069	330,355	199,310
564	8710		Distribution Load Dispatching		(41)	(12)	(9)	(0)	(10)	(11)
565	8711		Odorization		132,819	39,034	28,051	835	31,067	33,833
565	8720		Compressor Station Labor & Expenses		0	0	0	0	0	0
566	8740		Mains & Services		6,802,984	3,032,497	1,949,156	16,380	1,141,599	663,352
567	8750		Measuring and Regulating Station Exp. - Gen		1,361,535	606,918	390,100	3,278	228,477	132,762
568	8760		Measuring and Regulating Station Exp. - Ind.		523	0	518	0	3	2
569	8770		Measuring and Regulating Sta. Exp. - City Gate		5,487	2,446	1,572	13	921	535
570	8780		Meters and House Regulator Expense		938,471	653,413	266,517	821	11,060	6,659
571	8790		Customer Installations Expense		257	228	29	0	0	0
572	8800		Other Expense		3,085	1,438	877	7	476	287
573	8810		Rents		75,023	34,965	21,318	178	11,578	6,985
574			Maintenance							
575	8850		Maintenance Supervision and Engineering		0	0	0	0	0	0
576	8860		Maintenance of Structures and Improvements		0	0	0	0	0	0
577	8870		Maintenance of Mains		144,480	64,403	41,396	348	24,245	14,088
578	8890		Maintenance of compressor station equipment		140,590	41,317	29,692	884	32,884	35,812
579	8900		Maint. of Measuring and Regulating Station Equip. - General		0	0	0	0	0	0
580	8910		Maint. of Measuring and Regulating Station Equip. - Industrial		135	0	133	0	1	0
581	8920		Maint. of Measuring and Regulating Station Equip. - City Gate		178	79	51	0	30	17
582	8930		Maintenance of Services		0	0	0	0	0	0
583	8940		Maintenance of Meters and House Regulators		0	0	0	0	0	0
584	8950		Maintenance of Other Equipment		0	0	0	0	0	0
585			Total Distribution		11,746,231	5,474,417	3,337,680	27,814	1,812,687	1,093,633
586										
587			Customer Accounts:							
588	9010		Supervision		0	0	0	0	0	0
589	9020		Meter Reading Expense		735,288	652,684	81,800	36	480	289
590	9030		Customer Records and Collection Expenses		1,067,803	947,844	118,792	52	697	419
591	9040		Uncollectible Accounts		731,532	496,144	235,187	0	200	0
592	9050		Miscellaneous Customer Accounts Expenses		0	0	0	0	0	0
593			Total Customer Accounts		2,534,624	2,096,673	435,779	87	1,376	708
594										
595			Customer Service and Information:							
596	9070		Supervision		0	0	0	0	0	0
597	9080		Customer Assistance Expenses		0	0	0	0	0	0
598	9090		Informational and Instructional Advertising Expenses		214,461	190,368	23,859	10	140	84
599	9100		Miscellaneous Customer Service and Informational Expenses		0	0	0	0	0	0
600			Total Customer Service and Information		214,461	190,368	23,859	10	140	84
601										
602			Sales:							
603	9110		Supervision		158,549	140,737	17,638	8	103	62
604	9120		Demonstrating and Selling Expenses		77,078	68,419	8,575	4	50	30
605	9130		Advertising Expenses		36,821	32,685	4,096	2	24	14
606	9160		Miscellaneous Sales Expenses		(188,721)	(167,520)	(20,995)	(9)	(123)	(74)
607			Total Sales		83,728	74,321	9,315	4	55	33
608										
609			Administrative & General:							
610			Operation							
611	9200		Administrative and General Salaries		0	0	0	0	0	0
612	9210		Office Supplies and Expenses		69,069	34,887	18,520	149	9,676	5,838
613	9220		Administrative Expenses Transferred - Customer Support		0	0	0	0	0	0
614	9220		Administrative Expenses Transferred - General		18,251,309	9,218,782	4,893,841	39,297	2,556,811	1,542,579
615	9230		Outside Services Employed		69,993	35,354	18,768	151	9,805	5,916
616	9240		Property Insurance		0	0	0	0	0	0
617	9250		Injuries and Damages		23,257	11,747	6,236	50	3,258	1,966
618	9260		Employee Pensions and Benefits		872,759	440,833	234,018	1,879	122,264	73,765
619	9270		Franchise Requirements		635	564	71	0	0	0
620	9280		Regulatory Commission Expenses		165,392	146,811	18,400	8	108	65
621	930.1		General Advertising Expenses		0	0	0	0	0	0
622	930.2		Miscellaneous General Expense		24,411	12,330	6,545	53	3,420	2,063
623	ADJ		Adjustments		(1,404,321)	(709,326)	(376,550)	(3,024)	(196,730)	(118,692)
624			Maintenance							
625	9320		Maintenance of General Plant		0	0	0	0	0	0
626			Total A&G		18,072,504	9,191,981	4,819,849	38,562	2,508,612	1,513,499
627										
628			TOTAL O&M EXPENSE		120,959,622	67,850,323	45,125,285	910,909	4,419,948	2,653,157

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Customer

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1		Intangible Plant:								
2										
3	30100	Organization	99.0	-	0	-	-	-	-	-
4	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
5	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
6										
7		Total Intangible Plant:			0	-	-	-	-	-
8										
9		Production Plant:								
10			99.0	-	0	-	-	-	-	-
11	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
12	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
13	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
14	33201	Field Lines	99.0	-	0	-	-	-	-	-
15	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
16	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
17	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
18										
19		Total Production Plant			0	-	-	-	-	-
20										
21		Storage Plant:								
22										
23	35010	Land	99.0	-	0	-	-	-	-	-
24	35020	Rights of Way	99.0	-	0	-	-	-	-	-
25	35100	Structures and Improvements	99.0	-	0	-	-	-	-	-
26	35102	Compression Station Equipment	99.0	-	0	-	-	-	-	-
27	35103	Meas. & Reg. Sta. Structues	99.0	-	0	-	-	-	-	-
28	35104	Other Structures	99.0	-	0	-	-	-	-	-
29	35200	Wells \ Rights of Way	99.0	-	0	-	-	-	-	-
30	35201	Well Construction	99.0	-	0	-	-	-	-	-
31	35202	Well Equipment	99.0	-	0	-	-	-	-	-
32	35203	Cushion Gas	99.0	-	0	-	-	-	-	-
33	35210	Leaseholds	99.0	-	0	-	-	-	-	-
34	35211	Storage Rights	99.0	-	0	-	-	-	-	-
35	35301	Field Lines	99.0	-	0	-	-	-	-	-
36	35302	Tributary Lines	99.0	-	0	-	-	-	-	-
37	35400	Compressor Station Equipment	99.0	-	0	-	-	-	-	-
38	35500	Meas & Reg. Equipment	99.0	-	0	-	-	-	-	-
39	35600	Purification Equipment	99.0	-	0	-	-	-	-	-
40										
41		Total Storage Plant			0	-	-	-	-	-
42										
43		Transmission:								
44										
45	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
46	36520	Rights of Way	99.0	-	0	-	-	-	-	-
47	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
48	36603	Other Structues	99.0	-	0	-	-	-	-	-
49	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
50	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
51	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
52	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
53	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
54										
55		Total Transmission Plant			0	-	-	-	-	-
56										
57		Distribution:								
58										
59	37400	Land & Land Rights	2.0	Bills	0	-	-	-	-	-
60	37401	Land	2.0	Bills	0	-	-	-	-	-
61	37402	Land Rights	2.0	Bills	0	-	-	-	-	-
62	37403	Land Other	2.0	Bills	0	-	-	-	-	-
63	37500	Structures & Improvements	2.0	Bills	0	-	-	-	-	-
64	37501	Structures & Improvements T.B.	2.0	Bills	0	-	-	-	-	-
65	37502	Land Rights	2.0	Bills	0	-	-	-	-	-
66	37503	Improvements	2.0	Bills	0	-	-	-	-	-
67	37600	Mains Cathodic Protection	2.0	Bills	0	-	-	-	-	-
68	37601	Mains - Steel	2.0	Bills	0	-	-	-	-	-
69	37602	Mains - Plastic	2.0	Bills	0	-	-	-	-	-
70	37603	Mains - Anodes	2.0	Bills	0	-	-	-	-	-
71	37604	Mains - Leak Clamps	2.0	Bills	0	-	-	-	-	-
72	37800	Meas & Reg. Sta. Equip - General	2.0	Bills	0	-	-	-	-	-
73	37900	Meas & Reg. Sta. Equip - City Gate	2.0	Bills	0	-	-	-	-	-
74	37905	Meas & Reg. Sta. Equipment T.b.	2.0	Bills	0	-	-	-	-	-
75	38000	Services	2.0	Bills	4,814,131	4,273,300	535,566	233	3,141	1,891
76	38100	Meters	4.0	Meter Investment	2,722,922	1,895,843	773,286	2,381	32,091	19,321
77	38200	Meter Installaitons	4.0	Meter Investment	2,026,363	1,410,862	575,469	1,772	23,882	14,378
78	38300	House Regulators	4.0	Meter Investment	124,799	86,892	35,442	109	1,471	886
79	38400	House Reg. Installations	4.0	Meter Investment	12,401	8,635	3,522	11	146	88
80	38500	Ind. Meas. & Reg. Sta. Equipment	2.2	Non-Residential Bills	97,340	-	96,392	42	565	340
81	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
82										
83		Total Distribution Plant			9,797,957	7,675,532	2,019,678	4,548	61,296	36,903

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF DEPRECIATION EXPENSE										
84										
85		General:								
86										
87	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
88	39000	Structures Frame	6.2	P, S, T & D Plant - Customer	80,355	64,223	15,463	30	399	240
89	39001	Structures & Improvements	6.2	P, S, T & D Plant - Customer	1,501	1,200	289	1	7	4
90	39002	Improvements	6.2	P, S, T & D Plant - Customer	7,601	6,075	1,463	3	38	23
91	39003	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	197	158	38	0	1	1
92	39004	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
93	39009	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	32,417	25,909	6,238	12	161	97
94	39100	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
95	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
96	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	896	716	172	0	4	3
97	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
98	39202	Trailers	6.2	P, S, T & D Plant - Customer	181	145	35	0	1	1
99	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
100	39500	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	60,435	48,302	11,629	22	300	181
101	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
102	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
103	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
104	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
105	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	10,328	8,255	1,987	4	51	31
106	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
107	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
108	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
109	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	71,146	56,863	13,691	26	353	213
110	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
111	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
112	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
113	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
114	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
115	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
116	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	3,945	3,153	759	1	20	12
117	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
118	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
119	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
120	40600	Amortization of gas plant acquisition adjustments	6.2	P, S, T & D Plant - Customer	17,594	14,062	3,386	6	87	53
121										
122										
123		Total General Plant			286,597	229,061	55,149	106	1,424	857
124										
125		TOTAL DIRECT DEPRECIATION EXPENSE			10,084,554	7,904,593	2,074,827	4,654	62,720	37,761
126										
127		Kentucky Mid-States General Office:								
128										
129		Intangible Plant:								
130										
131	30100	Organization	99.0	-	0	-	-	-	-	-
132	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
133	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
134										
135		Total Intangible Plant:			0	-	-	-	-	-
136										
137		General:								
138										
139	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
140	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	1,407	1,125	271	1	7	4
141	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
142	38900	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
143	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	56	45	11	0	0	0
144	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
145	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	309	247	59	0	2	1
146	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
147	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
148	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	22	18	4	0	0	0
149	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
150	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
151	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
152	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	500	399	96	0	2	1
153	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	4	3	1	0	0	0
154	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
155	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
156	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
157	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
158	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
159	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
160	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
161	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
162	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
163	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
164	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
165	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	554	443	107	0	3	2
166	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
167	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
168	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
169	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
170	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
171	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
172	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
173										
174										
175		Total General Plant			2,851	2,278	549	1	14	9

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
176											
177		Shared Services General Office:									
178											
179		General:									
180											
181	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
182	39000	Structures & Improvements	6.2	P, S, T & D Plant - Customer	4,100	3,277	789	2	20	12
183	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
184	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
185	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
186	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	10,243	8,187	1,971	4	51	31
187	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	8,778	7,016	1,689	3	44	26
188	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
189	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
190	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	338	270	65	0	2	1
191	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
192	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
193	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
194	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	61	49	12	0	0	0
195	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
196	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
197	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
198	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
199	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	800	639	154	0	4	2
200	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
201	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
202	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
203	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	138	110	27	0	1	0
204	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
205	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	120,243	96,103	23,138	44	597	360
206	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	78,920	63,076	15,186	29	392	236
207	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	11,835	9,459	2,277	4	59	35
208	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
209	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
210	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	15,278	12,211	2,940	6	76	46
211	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	157	126	30	0	1	0
212	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
213	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	182,278	145,684	35,075	67	906	545
214	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
215	ADJ	WTW Adjustment	6.2	P, S, T & D Plant - Customer	(3,021)	(2,415)	(581)	(1)	(15)	(9)
216										
217		Total General Plant			430,147	343,793	82,773	159	2,137	1,287
218										
219		Shared Services Customer Support:								
220										
221		General:								
222										
223	37400	Land & Land Rights	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
224	39001	Structures Frame	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
225	36602	Structures & Improvements	6.2	P, S, T & D Plant - Customer	9,410	7,521	1,811	3	47	28
226	37503	Improvements	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
227	39004	Air Conditioning Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
228	39009	Improvement to leased Premises	6.2	P, S, T & D Plant - Customer	2,702	2,160	520	1	13	8
229	39100	Office Furniture & Equipment	6.2	P, S, T & D Plant - Customer	4,010	3,205	772	1	20	12
230	39102	Remittance Processing Equip	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
231	39103	Office Machines	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
232	39200	Transportation Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
233	39201	Trucks	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
234	39202	Trailers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
235	39300	Stores Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
236	39400	Tools, Shop & Garage Equipment	6.2	P, S, T & D Plant - Customer	945	756	182	0	5	3
237	39600	Power Operated Equipment	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
238	39603	Ditchers	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
239	39604	Backhoes	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
240	39605	Welders	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
241	39700	Communication Equipment	6.2	P, S, T & D Plant - Customer	2,396	1,915	461	1	12	7
242	39701	Communication Equipment - Mobile Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
243	39702	Communication Equipment - Fixed Radios	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
244	39705	Communication Equip. - Telemetering	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
245	39800	Miscellaneous Equipment	6.2	P, S, T & D Plant - Customer	750	599	144	0	4	2
246	39900	Other Tangible Property	6.2	P, S, T & D Plant - Customer	423	338	81	0	2	1
247	39901	Other Tangible Property - Servers - H/W	6.2	P, S, T & D Plant - Customer	13,762	10,999	2,648	5	68	41
248	39902	Other Tangible Property - Servers - S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
249	39903	Other Tangible Property - Network - H/W	6.2	P, S, T & D Plant - Customer	1,431	1,143	275	1	7	4
250	39904	Other Tang. Property - CPU	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
251	39905	Other Tangible Property - MF - Hardware	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
252	39906	Other Tang. Property - PC Hardware	6.2	P, S, T & D Plant - Customer	6,664	5,326	1,282	2	33	20
253	39907	Other Tang. Property - PC Software	6.2	P, S, T & D Plant - Customer	4	3	1	0	0	0
254	39908	Other Tang. Property - Mainframe S/W	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
255	39909	Other Tang. Property - Application Software	6.2	P, S, T & D Plant - Customer	143,560	114,740	27,625	53	713	429
256	39924	Other Tang. Property - General Startup Costs	6.2	P, S, T & D Plant - Customer	0	-	-	-	-	-
257										
258										
259		Total General Plant			186,058	148,706	35,803	69	924	556
260										
261	NTB	To Match Schedule C-1	6.2	P, S, T & D Plant - Customer	69	55	13	0	0	0
262										
263		TOTAL DEPRECIATION EXPENSE - CUSTOMER			10,703,678	8,399,424	2,193,964	4,882	65,795	39,612

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Demand

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
264		Intangible Plant:								
265										
266	30100	Organization	99.0	-	0	-	-	-	-	-
267	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
268	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
269										
270		Total Intangible Plant:			0	-	-	-	-	-
271										
272		Production Plant:								
273			3.0	Peak Day	0	-	-	-	-	-
274	32520	Producing Leaseholds	3.0	Peak Day	0	-	-	-	-	-
275	32540	Rights of Ways	3.0	Peak Day	0	-	-	-	-	-
276	33100	Production Gas Wells Equipment	3.0	Peak Day	0	-	-	-	-	-
277	33201	Field Lines	3.0	Peak Day	0	-	-	-	-	-
278	33202	Tributary Lines	3.0	Peak Day	0	-	-	-	-	-
279	33400	Field Meas. & Reg. Sta. Equip	3.0	Peak Day	0	-	-	-	-	-
280	33600	Purification Equipment	3.0	Peak Day	0	-	-	-	-	-
281										
282		Total Production Plant			0	-	-	-	-	-
283										
284		Storage Plant:								
285										
286	35010	Land	3.0	Peak Day	0	-	-	-	-	-
287	35020	Rights of Way	3.0	Peak Day	16	9	5	-	2	-
288	35100	Structures and Improvements	3.0	Peak Day	147	79	49	-	19	-
289	35102	Compression Station Equipment	3.0	Peak Day	1,531	827	510	-	194	-
290	35103	Meas. & Reg. Sta. Structues	3.0	Peak Day	127	69	42	-	16	-
291	35104	Other Structures	3.0	Peak Day	948	512	316	-	120	-
292	35200	Wells \ Rights of Way	3.0	Peak Day	120,988	65,328	40,317	-	15,344	-
293	35201	Well Construction	3.0	Peak Day	13,600	7,343	4,532	-	1,725	-
294	35202	Well Equipment	3.0	Peak Day	4,605	2,486	1,534	-	584	-
295	35203	Cushion Gas	3.0	Peak Day	11,864	6,406	3,953	-	1,505	-
296	35210	Leaseholds	3.0	Peak Day	500	270	167	-	63	-
297	35211	Storage Rights	3.0	Peak Day	279	150	93	-	35	-
298	35301	Field Lines	3.0	Peak Day	1,105	596	368	-	140	-
299	35302	Tributary Lines	3.0	Peak Day	1,319	712	439	-	167	-
300	35400	Compressor Station Equipment	3.0	Peak Day	154,463	83,403	51,472	-	19,589	-
301	35500	Meas & Reg. Equipment	3.0	Peak Day	2,553	1,379	851	-	324	-
302	35600	Purification Equipment	3.0	Peak Day	16,594	8,960	5,530	-	2,104	-
303										
304		Total Storage Plant			330,639	178,530	110,178	-	41,931	-
305										
306		Transmission:								
307										
308	36510	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
309	36520	Rights of Way	3.0	Peak Day	7,376	3,983	2,458	-	935	-
310	36602	Structures & Improvements	3.0	Peak Day	4,496	2,427	1,498	-	570	-
311	36603	Other Structues	3.0	Peak Day	0	-	-	-	-	-
312	36700	Mains Cathodic Protection	3.0	Peak Day	1,478	798	493	-	187	-
313	36701	Mains - Steel	3.0	Peak Day	384,012	207,348	127,964	-	48,700	-
314	36703	Mains - Anodes	3.0	Peak Day	0	-	-	-	-	-
315	36900	Meas. & Reg. Equipment	3.0	Peak Day	35,793	19,326	11,927	-	4,539	-
316	36901	Meas. & Reg. Equipment	3.0	Peak Day	40,624	21,935	13,537	-	5,152	-
317										
318		Total Transmission Plant			473,778	255,818	157,876	-	60,084	-
319										
320		Distribution:								
321										
322	37400	Land & Land Rights	3.0	Peak Day	0	-	-	-	-	-
323	37401	Land	3.0	Peak Day	0	-	-	-	-	-
324	37402	Land Rights	3.0	Peak Day	33,615	18,151	11,202	-	4,263	-
325	37403	Land Other	3.0	Peak Day	0	-	-	-	-	-
326	37500	Structures & Improvements	3.0	Peak Day	2,988	1,613	996	-	379	-
327	37501	Structures & Improvements T.B.	3.0	Peak Day	887	479	296	-	113	-
328	37502	Land Rights	3.0	Peak Day	411	222	137	-	52	-
329	37503	Improvements	3.0	Peak Day	36	19	12	-	5	-
330	37600	Mains Cathodic Protection	3.0	Peak Day	98,316	53,086	32,762	-	12,468	-
331	37601	Mains - Steel	3.0	Peak Day	2,193,681	1,184,486	730,997	-	278,199	-
332	37602	Mains - Plastic	3.0	Peak Day	2,108,600	1,138,545	702,646	-	267,409	-
333	37603	Mains - Anodes	3.0	Peak Day	123,886	66,892	41,282	-	15,711	-
334	37604	Mains - Leak Clamps	3.0	Peak Day	209,538	113,141	69,824	-	26,573	-
335	37800	Meas & Reg. Sta. Equip - General	3.0	Peak Day	354,035	191,162	117,974	-	44,898	-
336	37900	Meas & Reg. Sta. Equip - City Gate	3.0	Peak Day	132,536	71,563	44,165	-	16,808	-
337	37905	Meas & Reg. Sta. Equipment T.b.	3.0	Peak Day	23,014	12,426	7,669	-	2,919	-
338	38000	Services	99.0	-	0	-	-	-	-	-
339	38100	Meters	99.0	-	0	-	-	-	-	-
340	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
341	38300	House Regulators	99.0	-	0	-	-	-	-	-
342	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
343	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
344	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
345										
346		Total Distribution Plant			5,281,542	2,851,786	1,759,961	-	669,796	-

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
347											
348		General:									
349											
350	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
351	39000	Structures Frame	6.4	P, S, T & D Plant - Demand	91,496	49,403	30,489	-	11,603	-	
352	39001	Structures & Improvements	6.4	P, S, T & D Plant - Demand	1,709	923	570	-	217	-	
353	39002	Improvements	6.4	P, S, T & D Plant - Demand	8,655	4,673	2,884	-	1,098	-	
354	39003	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	225	121	75	-	29	-	
355	39004	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
356	39009	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	36,912	19,931	12,300	-	4,681	-	
357	39100	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
358	39102	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
359	39103	Transportation Equipment	6.4	P, S, T & D Plant - Demand	1,020	551	340	-	129	-	
360	39200	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
361	39201	Trailers	6.4	P, S, T & D Plant - Demand	207	112	69	-	26	-	
362	39202	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
363	39300	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	68,814	37,156	22,931	-	8,727	-	
364	39400	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
365	39600	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
366	39603	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
367	39604	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
368	39605	Communication Equipment	6.4	P, S, T & D Plant - Demand	11,760	6,350	3,919	-	1,491	-	
369	39700	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
370	39701	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
371	39702	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
372	39705	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	81,010	43,742	26,995	-	10,274	-	
373	39800	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
374	39900	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
375	39901	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
376	39902	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
377	39903	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
378	39904	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
379	39905	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	4,492	2,425	1,497	-	570	-	
380	39906	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
381	39907	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
382	39908	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
383	40600	Amortization of gas plant acquisition adjustments	6.4	P, S, T & D Plant - Demand	20,033	10,817	6,676	-	2,541	-	
384											
385											
386		Total General Plant			326,334	176,205	108,744	0	41,385	0	
387											
388		TOTAL DIRECT DEPRECIATION EXPENSE			6,412,293	3,462,339	2,136,759	0	813,195	0	
389											
390		Kentucky Mid-States General Office:									
391											
392		Intangible Plant:									
393											
394	30100	Organization	99.0	-	0	-	-	-	-	-	
395	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-	
396	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-	
397											
398		Total Intangible Plant:			0	-	-	-	-	-	
399											
400		General:									
401											
402	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
403	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	1,602	865	534	-	203	-	
404	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
405	38900	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
406	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	63	34	21	-	8	-	
407	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
408	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	352	190	117	-	45	-	
409	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
410	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
411	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	25	14	8	-	3	-	
412	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
413	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
414	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
415	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	569	307	190	-	72	-	
416	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	4	2	1	-	1	-	
417	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
418	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
419	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
420	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
421	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
422	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
423	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
424	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
425	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
426	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
427	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
428	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	631	341	210	-	80	-	
429	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
430	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
431	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
432	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
433	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
434	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
435	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
436											
437											
438		Total General Plant			3,246	1,753	1,082	-	412	-	

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
439											
440		Shared Services General Office:									
441											
442		General:									
443											
444	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
445	39000	Structures & Improvements	6.4	P, S, T & D Plant - Demand	4,668	2,521	1,556	-	592	-	
446	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
447	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
448	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
449	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	11,664	6,298	3,887	-	1,479	-	
450	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	9,995	5,397	3,331	-	1,268	-	
451	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
452	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
453	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	385	208	128	-	49	-	
454	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
455	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
456	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
457	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	69	38	23	-	9	-	
458	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
459	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
460	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
461	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
462	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	911	492	304	-	116	-	
463	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
464	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
465	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
466	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	157	85	52	-	20	-	
467	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
468	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	136,915	73,927	45,624	-	17,363	-	
469	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	89,862	48,521	29,945	-	11,396	-	
470	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	13,475	7,276	4,490	-	1,709	-	
471	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
472	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
473	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	17,396	9,393	5,797	-	2,206	-	
474	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	179	97	60	-	23	-	
475	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
476	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	207,550	112,067	69,162	-	26,321	-	
477	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
478	ADJ	WTW Adjustment	6.4	P, S, T & D Plant - Demand	(3,440)	(1,858)	(1,146)	-	(436)	-	
479											
480		Total General Plant			489,787	264,462	163,211	-	62,114	-	
481											
482		Shared Services Customer Support:									
483											
484		General:									
485											
486	37400	Land & Land Rights	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
487	39001	Structures Frame	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
488	36602	Structures & Improvements	6.4	P, S, T & D Plant - Demand	10,715	5,786	3,571	-	1,359	-	
489	37503	Improvements	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
490	39004	Air Conditioning Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
491	39009	Improvement to leased Premises	6.4	P, S, T & D Plant - Demand	3,077	1,661	1,025	-	390	-	
492	39100	Office Furniture & Equipment	6.4	P, S, T & D Plant - Demand	4,566	2,465	1,521	-	579	-	
493	39102	Remittance Processing Equip	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
494	39103	Office Machines	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
495	39200	Transportation Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
496	39201	Trucks	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
497	39202	Trailers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
498	39300	Stores Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
499	39400	Tools, Shop & Garage Equipment	6.4	P, S, T & D Plant - Demand	1,076	581	359	-	137	-	
500	39600	Power Operated Equipment	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
501	39603	Ditchers	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
502	39604	Backhoes	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
503	39605	Welders	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
504	39700	Communication Equipment	6.4	P, S, T & D Plant - Demand	2,728	1,473	909	-	346	-	
505	39701	Communication Equipment - Mobile Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
506	39702	Communication Equipment - Fixed Radios	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
507	39705	Communication Equip. - Telemetering	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
508	39800	Miscellaneous Equipment	6.4	P, S, T & D Plant - Demand	854	461	284	-	108	-	
509	39900	Other Tangible Property	6.4	P, S, T & D Plant - Demand	482	260	161	-	61	-	
510	39901	Other Tangible Property - Servers - H/W	6.4	P, S, T & D Plant - Demand	15,670	8,461	5,222	-	1,987	-	
511	39902	Other Tangible Property - Servers - S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
512	39903	Other Tangible Property - Network - H/W	6.4	P, S, T & D Plant - Demand	1,629	880	543	-	207	-	
513	39904	Other Tang. Property - CPU	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
514	39905	Other Tangible Property - MF - Hardware	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
515	39906	Other Tang. Property - PC Hardware	6.4	P, S, T & D Plant - Demand	7,588	4,097	2,529	-	962	-	
516	39907	Other Tang. Property - PC Software	6.4	P, S, T & D Plant - Demand	5	3	2	-	1	-	
517	39908	Other Tang. Property - Mainframe S/W	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
518	39909	Other Tang. Property - Application Software	6.4	P, S, T & D Plant - Demand	163,465	88,263	54,471	-	20,730	-	
519	39924	Other Tang. Property - General Startup Costs	6.4	P, S, T & D Plant - Demand	0	-	-	-	-	-	
520											
521											
522		Total General Plant			211,854	114,392	70,596	-	26,867	-	
523											
524	NTB	To Match Schedule C-1	6.4	P, S, T & D Plant - Demand	78	42	26	-	10	-	
525											
526		TOTAL DEPRECIATION EXPENSE - DEMAND			7,117,258	3,842,987	2,371,674	0	902,598	0	

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Commodity

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
527		Intangible Plant:								
528										
529	30100	Organization	99.0	-	0	-	-	-	-	-
530	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
531	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
532										
533		Total Intangible Plant:			0	-	-	-	-	-
534										
535		Production Plant:								
536			99.0	-	0	-	-	-	-	-
537	32520	Producing Leaseholds	99.0	-	0	-	-	-	-	-
538	32540	Rights of Ways	99.0	-	0	-	-	-	-	-
539	33100	Production Gas Wells Equipment	99.0	-	0	-	-	-	-	-
540	33201	Field Lines	99.0	-	0	-	-	-	-	-
541	33202	Tributary Lines	99.0	-	0	-	-	-	-	-
542	33400	Field Meas. & Reg. Sta. Equip	99.0	-	0	-	-	-	-	-
543	33600	Purification Equipment	99.0	-	0	-	-	-	-	-
544										
545		Total Production Plant			0	-	-	-	-	-
546										
547		Storage Plant:								
548										
549	35010	Land	1.5	Winter Volumes	0	-	-	-	-	-
550	35020	Rights of Way	1.5	Winter Volumes	16	6	4	0	3	3
551	35100	Structures and Improvements	1.5	Winter Volumes	147	56	37	1	26	27
552	35102	Compression Station Equipment	1.5	Winter Volumes	1,531	582	384	8	273	285
553	35103	Meas. & Reg. Sta. Structues	1.5	Winter Volumes	127	48	32	1	23	24
554	35104	Other Structures	1.5	Winter Volumes	948	360	238	5	169	176
555	35200	Wells \ Rights of Way	1.5	Winter Volumes	120,988	45,964	30,335	654	21,547	22,489
556	35201	Well Construction	1.5	Winter Volumes	13,600	5,167	3,410	73	2,422	2,528
557	35202	Well Equipment	1.5	Winter Volumes	4,605	1,749	1,155	25	820	856
558	35203	Cushion Gas	1.5	Winter Volumes	11,864	4,507	2,975	64	2,113	2,205
559	35210	Leaseholds	1.5	Winter Volumes	500	190	125	3	89	93
560	35211	Storage Rights	1.5	Winter Volumes	279	106	70	2	50	52
561	35301	Field Lines	1.5	Winter Volumes	1,105	420	277	6	197	205
562	35302	Tributary Lines	1.5	Winter Volumes	1,319	501	331	7	235	245
563	35400	Compressor Station Equipment	1.5	Winter Volumes	154,463	58,681	38,728	834	27,509	28,711
564	35500	Meas & Reg. Equipment	1.5	Winter Volumes	2,553	970	640	14	455	475
565	35600	Purification Equipment	1.5	Winter Volumes	16,594	6,304	4,160	90	2,955	3,084
566										
567		Total Storage Plant			330,639	125,611	82,900	1,786	58,884	61,458
568										
569		Transmission:								
570										
571	36510	Land & Land Rights	99.0	-	0	-	-	-	-	-
572	36520	Rights of Way	99.0	-	0	-	-	-	-	-
573	36602	Structures & Improvements	99.0	-	0	-	-	-	-	-
574	36603	Other Structues	99.0	-	0	-	-	-	-	-
575	36700	Mains Cathodic Protection	99.0	-	0	-	-	-	-	-
576	36701	Mains - Steel	99.0	-	0	-	-	-	-	-
577	36703	Mains - Anodes	99.0	-	0	-	-	-	-	-
578	36900	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
579	36901	Meas. & Reg. Equipment	99.0	-	0	-	-	-	-	-
580										
581		Total Transmission Plant			0	-	-	-	-	-
582										
583		Distribution:								
584										
585	37400	Land & Land Rights	99.0	-	0	-	-	-	-	-
586	37401	Land	99.0	-	0	-	-	-	-	-
587	37402	Land Rights	1.0	Mcf	20,848	6,127	4,403	131	4,876	5,311
588	37403	Land Other	99.0	-	0	-	-	-	-	-
589	37500	Structures & Improvements	1.0	Mcf	1,853	545	391	12	433	472
590	37501	Structures & Improvements T.B.	1.0	Mcf	550	162	116	3	129	140
591	37502	Land Rights	1.0	Mcf	255	75	54	2	60	65
592	37503	Improvements	1.0	Mcf	22	6	5	0	5	6
593	37600	Mains Cathodic Protection	1.0	Mcf	60,976	17,920	12,878	384	14,262	15,532
594	37601	Mains - Steel	1.0	Mcf	1,360,525	399,837	287,336	8,558	318,228	346,567
595	37602	Mains - Plastic	1.0	Mcf	1,307,758	384,329	276,192	8,226	305,885	333,125
596	37603	Mains - Anodes	1.0	Mcf	76,834	22,580	16,227	483	17,972	19,572
597	37604	Mains - Leak Clamps	1.0	Mcf	129,956	38,192	27,446	817	30,397	33,104
598	37800	Meas & Reg. Sta. Equip - General	1.0	Mcf	219,573	64,529	46,373	1,381	51,358	55,932
599	37900	Meas & Reg. Sta. Equip - City Gate	1.0	Mcf	82,199	24,157	17,360	517	19,226	20,939
600	37905	Meas & Reg. Sta. Equipment T.b.	1.0	Mcf	14,273	4,195	3,014	90	3,339	3,636
601	38000	Services	99.0	-	0	-	-	-	-	-
602	38100	Meters	99.0	-	0	-	-	-	-	-
603	38200	Meter Installaitons	99.0	-	0	-	-	-	-	-
604	38300	House Regulators	99.0	-	0	-	-	-	-	-
605	38400	House Reg. Installations	99.0	-	0	-	-	-	-	-
606	38500	Ind. Meas. & Reg. Sta. Equipment	99.0	-	0	-	-	-	-	-
607	38600	Other Prop. On Cust. Prem	99.0	-	0	-	-	-	-	-
608										
609		Total Distribution Plant			3,275,623	962,654	691,795	20,604	766,171	834,400

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF DEPRECIATION EXPENSE										
610										
611		General:								
612										
613	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
614	39000	Structures Frame	6.6	P, S, T & D Plant - Commodity	53,336	16,078	11,450	331	12,214	13,263
615	39001	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	996	300	214	6	228	248
616	39002	Improvements	6.6	P, S, T & D Plant - Commodity	5,045	1,521	1,083	31	1,155	1,255
617	39003	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	131	39	28	1	30	33
618	39004	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
619	39009	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	21,517	6,486	4,619	134	4,927	5,351
620	39100	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
621	39102	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
622	39103	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	595	179	128	4	136	148
623	39200	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
624	39201	Trailers	6.6	P, S, T & D Plant - Commodity	120	36	26	1	28	30
625	39202	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
626	39300	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	40,114	12,092	8,611	249	9,186	9,975
627	39400	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
628	39600	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
629	39603	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
630	39604	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
631	39605	Communication Equipment	6.6	P, S, T & D Plant - Commodity	6,855	2,067	1,472	43	1,570	1,705
632	39700	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
633	39701	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
634	39702	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
635	39705	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	47,224	14,235	10,138	293	10,814	11,743
636	39800	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
637	39900	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
638	39901	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
639	39902	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
640	39903	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
641	39904	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
642	39905	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	2,619	789	562	16	600	651
643	39906	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
644	39907	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
645	39908	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
646	40600	Amortization of gas plant acquisition adjustments	6.6	P, S, T & D Plant - Commodity	11,678	3,520	2,507	73	2,674	2,904
647										
648										
649		Total General Plant			190,230	57,345	40,837	1,182	43,562	47,306
650										
651		TOTAL DIRECT DEPRECIATION EXPENSE			3,796,492	1,145,609	815,531	23,571	868,617	943,164
652										
653		Kentucky Mid-States General Office:								
654										
655		Intangible Plant:								
656										
657	30100	Organization	99.0	-	0	-	-	-	-	-
658	30200	Franchises & Consents	99.0	-	0	-	-	-	-	-
659	30300	Misc Intangible Plant	99.0	-	0	-	-	-	-	-
660										
661		Total Intangible Plant:			0	-	-	-	-	-
662										
663		General:								
664										
665	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
666	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	934	282	200	6	214	232
667	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
668	38900	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
669	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	37	11	8	0	8	9
670	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
671	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	205	62	44	1	47	51
672	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
673	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
674	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	15	4	3	0	3	4
675	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
676	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
677	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
678	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	332	100	71	2	76	82
679	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	2	1	0	0	1	1
680	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
681	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
682	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
683	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
684	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
685	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
686	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
687	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
688	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
689	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
690	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
691	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	368	111	79	2	84	91
692	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
693	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
694	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
695	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
696	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
697	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
698	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
699										
700										
701		Total General Plant			1,892	570	406	12	433	471
702										
703		Shared Services General Office:								

Atmos Energy Corporation, Kentucky/Mid-States Division										
Class Cost of Service - Energy/Demand Study										
Forecasted Test Period: Twelve Months Ended March 31, 2026										
ALLOCATION OF DEPRECIATION EXPENSE										
704										
705		General:								
706										
707	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
708	39000	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	2,721	820	584	17	623	677
709	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
710	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
711	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
712	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	6,799	2,050	1,460	42	1,557	1,691
713	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	5,827	1,756	1,251	36	1,334	1,449
714	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
715	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
716	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	225	68	48	1	51	56
717	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
718	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
719	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
720	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	41	12	9	0	9	10
721	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
722	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
723	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
724	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
725	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	531	160	114	3	122	132
726	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
727	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
728	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
729	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	91	28	20	1	21	23
730	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
731	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	79,812	24,059	17,133	496	18,276	19,847
732	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	52,384	15,791	11,245	325	11,996	13,027
733	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	7,855	2,368	1,686	49	1,799	1,953
734	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
735	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
736	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	10,141	3,057	2,177	63	2,322	2,522
737	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	104	31	22	1	24	26
738	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
739	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	120,988	36,471	25,973	752	27,705	30,087
740	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
741	ADJ	WTW Adjustment	6.6	P, S, T & D Plant - Commodity	(2,005)	(605)	(431)	(12)	(459)	(499)
742										
743		Total General Plant			285,513	86,067	61,291	1,774	65,381	71,000
744										
745		Shared Services Customer Support:								
746										
747		General:								
748										
749	37400	Land & Land Rights	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
750	39001	Structures Frame	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
751	36602	Structures & Improvements	6.6	P, S, T & D Plant - Commodity	6,246	1,883	1,341	39	1,430	1,553
752	37503	Improvements	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
753	39004	Air Conditioning Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
754	39009	Improvement to leased Premises	6.6	P, S, T & D Plant - Commodity	1,794	541	385	11	411	446
755	39100	Office Furniture & Equipment	6.6	P, S, T & D Plant - Commodity	2,662	802	571	17	609	662
756	39102	Remittance Processing Equip	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
757	39103	Office Machines	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
758	39200	Transportation Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
759	39201	Trucks	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
760	39202	Trailers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
761	39300	Stores Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
762	39400	Tools, Shop & Garage Equipment	6.6	P, S, T & D Plant - Commodity	627	189	135	4	144	156
763	39600	Power Operated Equipment	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
764	39603	Ditchers	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
765	39604	Backhoes	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
766	39605	Welders	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
767	39700	Communication Equipment	6.6	P, S, T & D Plant - Commodity	1,590	479	341	10	364	395
768	39701	Communication Equipment - Mobile Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
769	39702	Communication Equipment - Fixed Radios	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
770	39705	Communication Equip. - Telemetering	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
771	39800	Miscellaneous Equipment	6.6	P, S, T & D Plant - Commodity	498	150	107	3	114	124
772	39900	Other Tangible Property	6.6	P, S, T & D Plant - Commodity	281	85	60	2	64	70
773	39901	Other Tangible Property - Servers - H/W	6.6	P, S, T & D Plant - Commodity	9,135	2,754	1,961	57	2,092	2,272
774	39902	Other Tangible Property - Servers - S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
775	39903	Other Tangible Property - Network - H/W	6.6	P, S, T & D Plant - Commodity	950	286	204	6	217	236
776	39904	Other Tang. Property - CPU	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
777	39905	Other Tangible Property - MF - Hardware	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
778	39906	Other Tang. Property - PC Hardware	6.6	P, S, T & D Plant - Commodity	4,423	1,333	950	27	1,013	1,100
779	39907	Other Tang. Property - PC Software	6.6	P, S, T & D Plant - Commodity	3	1	1	0	1	1
780	39908	Other Tang. Property - Mainframe S/W	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
781	39909	Other Tang. Property - Application Software	6.6	P, S, T & D Plant - Commodity	95,289	28,725	20,456	592	21,821	23,696
782	39924	Other Tang. Property - General Startup Costs	6.6	P, S, T & D Plant - Commodity	0	-	-	-	-	-
783										
784										
785		Total General Plant			123,497	37,228	26,511	767	28,280	30,711
786										
787	NTB	To Match Schedule C-1	6.6	P, S, T & D Plant - Commodity	45	14	10	0	10	11
788										
789		TOTAL DEPRECIATION EXPENSE - COMMODITY			4,207,439	1,269,488	903,750	26,124	962,721	1,045,356

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF DEPRECIATION EXPENSE

Total Depreciation Expense

Line No.	Acct. No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
790		Intangible Plant:								
791										
792	30100	Organization			0	-	-	-	-	-
793	30200	Franchises & Consents			0	-	-	-	-	-
794	30300	Misc Intangible Plant			0	-	-	-	-	-
795										
796		Total Intangible Plant:			0	-	-	-	-	-
797										
798		Production Plant:								
799					0	-	-	-	-	-
800	32520	Producing Leaseholds			0	-	-	-	-	-
801	32540	Rights of Ways			0	-	-	-	-	-
802	33100	Production Gas Wells Equipment			0	-	-	-	-	-
803	33201	Field Lines			0	-	-	-	-	-
804	33202	Tributary Lines			0	-	-	-	-	-
805	33400	Field Meas. & Reg. Sta. Equip			0	-	-	-	-	-
806	33600	Purification Equipment			0	-	-	-	-	-
807										
808		Total Production Plant			0	-	-	-	-	-
809										
810		Storage Plant:								
811										
812	35010	Land			0	-	-	-	-	-
813	35020	Rights of Way			32	15	9	0	5	3
814	35100	Structures and Improvements			294	135	86	1	45	27
815	35102	Compression Station Equipment			3,062	1,408	894	8	467	285
816	35103	Meas. & Reg. Sta. Structues			255	117	74	1	39	24
817	35104	Other Structures			1,897	872	554	5	289	176
818	35200	Wells \ Rights of Way			241,977	111,292	70,652	654	36,891	22,489
819	35201	Well Construction			27,200	12,510	7,942	73	4,147	2,528
820	35202	Well Equipment			9,210	4,236	2,689	25	1,404	856
821	35203	Cushion Gas			23,728	10,913	6,928	64	3,617	2,205
822	35210	Leaseholds			1,000	460	292	3	152	93
823	35211	Storage Rights			557	256	163	2	85	52
824	35301	Field Lines			2,209	1,016	645	6	337	205
825	35302	Tributary Lines			2,637	1,213	770	7	402	245
826	35400	Compressor Station Equipment			308,927	142,084	90,200	834	47,098	28,711
827	35500	Meas & Reg. Equipment			5,107	2,349	1,491	14	779	475
828	35600	Purification Equipment			33,187	15,264	9,690	90	5,060	3,084
829										
830		Total Storage Plant			661,278	304,140	193,078	1,786	100,815	61,458
831										
832		Transmission:								
833										
834	36510	Land & Land Rights			0	-	-	-	-	-
835	36520	Rights of Way			7,376	3,983	2,458	-	935	-
836	36602	Structures & Improvements			4,496	2,427	1,498	-	570	-
837	36603	Other Structues			0	-	-	-	-	-
838	36700	Mains Cathodic Protection			1,478	798	493	-	187	-
839	36701	Mains - Steel			384,012	207,348	127,964	-	48,700	-
840	36703	Mains - Anodes			0	-	-	-	-	-
841	36900	Meas. & Reg. Equipment			35,793	19,326	11,927	-	4,539	-
842	36901	Meas. & Reg. Equipment			40,624	21,935	13,537	-	5,152	-
843										
844		Total Transmission Plant			473,778	255,818	157,876	-	60,084	-
845										
846		Distribution:								
847										
848	37400	Land & Land Rights			0	-	-	-	-	-
849	37401	Land			0	-	-	-	-	-
850	37402	Land Rights			54,464	24,278	15,605	131	9,139	5,311
851	37403	Land Other			0	-	-	-	-	-
852	37500	Structures & Improvements			4,841	2,158	1,387	12	812	472
853	37501	Structures & Improvements T.B.			1,437	641	412	3	241	140
854	37502	Land Rights			666	297	191	2	112	65
855	37503	Improvements			58	26	17	0	10	6
856	37600	Mains Cathodic Protection			159,292	71,006	45,640	384	26,731	15,532
857	37601	Mains - Steel			3,554,207	1,584,322	1,018,333	8,558	596,427	346,567
858	37602	Mains - Plastic			3,416,357	1,522,875	978,837	8,226	573,294	333,125
859	37603	Mains - Anodes			200,720	89,473	57,509	483	33,683	19,572
860	37604	Mains - Leak Clamps			339,494	151,333	97,270	817	56,970	33,104
861	37800	Meas & Reg. Sta. Equip - General			573,607	255,691	164,347	1,381	96,256	55,932
862	37900	Meas & Reg. Sta. Equip - City Gate			214,735	95,720	61,525	517	36,034	20,939
863	37905	Meas & Reg. Sta. Equipment T.b.			37,287	16,621	10,683	90	6,257	3,636
864	38000	Services			4,814,131	4,273,300	535,566	233	3,141	1,891
865	38100	Meters			2,722,922	1,895,843	773,286	2,381	32,091	19,321
866	38200	Meter Installaitons			2,026,363	1,410,862	575,469	1,772	23,882	14,378
867	38300	House Regulators			124,799	86,892	35,442	109	1,471	886
868	38400	House Reg. Installations			12,401	8,635	3,522	11	146	88
869	38500	Ind. Meas. & Reg. Sta. Equipment			97,340	-	96,392	42	565	340
870	38600	Other Prop. On Cust. Prem			0	-	-	-	-	-
871										
872		Total Distribution Plant			18,355,122	11,489,972	4,471,433	25,152	1,497,262	871,304

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
873											
874		General:									
875											
876	38900	Land & Land Rights			0	-	-	-	-	-	
877	39000	Structures Frame			225,186	129,704	57,401	361	24,216	13,504	
878	39001	Structures & Improvements			4,207	2,423	1,072	7	452	252	
879	39002	Improvements			21,302	12,270	5,430	34	2,291	1,277	
880	39003	Air Conditioning Equipment			553	319	141	1	59	33	
881	39004	Improvement to leased Premises			0	-	-	-	-	-	
882	39009	Office Furniture & Equipment			90,847	52,327	23,157	146	9,769	5,448	
883	39100	Remittance Processing Equip			0	-	-	-	-	-	
884	39102	Office Machines			0	-	-	-	-	-	
885	39103	Transportation Equipment			2,511	1,446	640	4	270	151	
886	39200	Trucks			0	-	-	-	-	-	
887	39201	Trailers			508	293	130	1	55	30	
888	39202	Stores Equipment			0	-	-	-	-	-	
889	39300	Tools, Shop & Garage Equipment			169,362	97,550	43,171	271	18,213	10,156	
890	39400	Power Operated Equipment			0	-	-	-	-	-	
891	39600	Ditchers			0	-	-	-	-	-	
892	39603	Backhoes			0	-	-	-	-	-	
893	39604	Welders			0	-	-	-	-	-	
894	39605	Communication Equipment			28,944	16,671	7,378	46	3,113	1,736	
895	39700	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
896	39701	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
897	39702	Communication Equip. - Telemetering			0	-	-	-	-	-	
898	39705	Miscellaneous Equipment			199,380	114,840	50,823	320	21,441	11,956	
899	39800	Other Tangible Property			0	-	-	-	-	-	
900	39900	Other Tangible Property - Servers - H/W			0	-	-	-	-	-	
901	39901	Other Tangible Property - Servers - S/W			0	-	-	-	-	-	
902	39902	Other Tangible Property - Network - H/W			0	-	-	-	-	-	
903	39903	Other Tang. Property - CPU			0	-	-	-	-	-	
904	39904	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
905	39905	Other Tang. Property - PC Hardware			11,055	6,368	2,818	18	1,189	663	
906	39906	Other Tang. Property - PC Software			0	-	-	-	-	-	
907	39907	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
908	39908	Other Tang. Property - Application Software			0	-	-	-	-	-	
909	40600	Amortization of gas plant acquisition adjustments			49,305	28,399	12,568	79	5,302	2,957	
910											
911											
912		Total General Plant			803,161	462,610	204,730	1,287	86,370	48,163	
913											
914		TOTAL DIRECT DEPRECIATION EXPENSE			20,293,339	12,512,540	5,027,117	28,225	1,744,531	980,925	
915											
916		Kentucky Mid-States General Office:									
917											
918		Intangible Plant:									
919											
920	30100	Organization			0	-	-	-	-	-	
921	30200	Franchises & Consents			0	-	-	-	-	-	
922	30300	Misc Intangible Plant			0	-	-	-	-	-	
923											
924		Total Intangible Plant:			0	-	-	-	-	-	
925											
926		General:									
927											
928	37400	Land & Land Rights			0	-	-	-	-	-	
929	39001	Structures Frame			3,943	2,271	1,005	6	424	236	
930	36602	Structures & Improvements			0	-	-	-	-	-	
931	38900	Land & Land Rights			0	-	-	-	-	-	
932	39004	Air Conditioning Equipment			156	90	40	0	17	9	
933	39009	Improvement to leased Premises			0	-	-	-	-	-	
934	39100	Office Furniture & Equipment			865	498	221	1	93	52	
935	39102	Remittance Processing Equip			0	-	-	-	-	-	
936	39103	Office Machines			0	-	-	-	-	-	
937	39200	Transportation Equipment			62	36	16	0	7	4	
938	39201	Trucks			0	-	-	-	-	-	
939	39202	Trailers			0	-	-	-	-	-	
940	39300	Stores Equipment			0	-	-	-	-	-	
941	39400	Tools, Shop & Garage Equipment			1,400	807	357	2	151	84	
942	39600	Power Operated Equipment			10	6	3	0	1	1	
943	39603	Ditchers			0	-	-	-	-	-	
944	39604	Backhoes			0	-	-	-	-	-	
945	39605	Welders			0	-	-	-	-	-	
946	39700	Communication Equipment			0	-	-	-	-	-	
947	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
948	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
949	39705	Communication Equip. - Telemetering			0	-	-	-	-	-	
950	39800	Miscellaneous Equipment			0	-	-	-	-	-	
951	39900	Other Tangible Property			0	-	-	-	-	-	
952	39901	Other Tangible Property - Servers - H/W			0	-	-	-	-	-	
953	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-	
954	39903	Other Tangible Property - Network - H/W			1,552	894	396	2	167	93	
955	39904	Other Tang. Property - CPU			0	-	-	-	-	-	
956	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
957	39906	Other Tang. Property - PC Hardware			0	-	-	-	-	-	
958	39907	Other Tang. Property - PC Software			0	-	-	-	-	-	
959	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
960	39909	Other Tang. Property - Application Software			0	-	-	-	-	-	
961	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-	
962											
963											
964		Total General Plant			7,989	4,601	2,036	13	859	479	
965											
966		Shared Services General Office:									

Atmos Energy Corporation, Kentucky/Mid-States Division											
Class Cost of Service - Energy/Demand Study											
Forecasted Test Period: Twelve Months Ended March 31, 2026											
ALLOCATION OF DEPRECIATION EXPENSE											
967											
968		General:									
969											
970	37400	Land & Land Rights			0	-	-	-	-	-	
971	39000	Structures & Improvements			11,489	6,618	2,929	18	1,236	689	
972	36602	Structures & Improvements			0	-	-	-	-	-	
973	37503	Improvements			0	-	-	-	-	-	
974	39004	Air Conditioning Equipment			0	-	-	-	-	-	
975	39009	Improvement to leased Premises			28,706	16,534	7,317	46	3,087	1,721	
976	39100	Office Furniture & Equipment			24,600	14,169	6,271	39	2,645	1,475	
977	39102	Remittance Processing Equip			0	-	-	-	-	-	
978	39103	Office Machines			0	-	-	-	-	-	
979	39200	Transportation Equipment			948	546	242	2	102	57	
980	39201	Trucks			0	-	-	-	-	-	
981	39202	Trailers			0	-	-	-	-	-	
982	39300	Stores Equipment			0	-	-	-	-	-	
983	39400	Tools, Shop & Garage Equipment			171	99	44	0	18	10	
984	39600	Power Operated Equipment			0	-	-	-	-	-	
985	39603	Ditchers			0	-	-	-	-	-	
986	39604	Backhoes			0	-	-	-	-	-	
987	39605	Welders			0	-	-	-	-	-	
988	39700	Communication Equipment			2,242	1,291	571	4	241	134	
989	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
990	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
991	39705	Communication Equip. - Telemetering			0	-	-	-	-	-	
992	39800	Miscellaneous Equipment			386	222	98	1	42	23	
993	39900	Other Tangible Property			0	-	-	-	-	-	
994	39901	Other Tangible Property - Servers - H/W			336,969	194,090	85,895	540	36,237	20,207	
995	39902	Other Tangible Property - Servers - S/W			221,166	127,389	56,376	354	23,784	13,263	
996	39903	Other Tangible Property - Network - H/W			33,165	19,103	8,454	53	3,567	1,989	
997	39904	Other Tang. Property - CPU			0	-	-	-	-	-	
998	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
999	39906	Other Tang. Property - PC Hardware			42,815	24,661	10,914	69	4,604	2,567	
1000	39907	Other Tang. Property - PC Software			440	253	112	1	47	26	
1001	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
1002	39909	Other Tang. Property - Application Software			510,816	294,223	130,210	819	54,932	30,632	
1003	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-	
1004	ADJ	WTW Adjustment			(8,467)	(4,877)	(2,158)	(14)	(911)	(508)	
1005											
1006		Total General Plant			1,205,447	694,322	307,275	1,932	129,631	72,287	
1007											
1008		Shared Services Customer Support:									
1009											
1010		General:									
1011											
1012	37400	Land & Land Rights			0	-	-	-	-	-	
1013	39001	Structures Frame			0	-	-	-	-	-	
1014	36602	Structures & Improvements			26,371	15,190	6,722	42	2,836	1,581	
1015	37503	Improvements			0	-	-	-	-	-	
1016	39004	Air Conditioning Equipment			0	-	-	-	-	-	
1017	39009	Improvement to leased Premises			7,572	4,362	1,930	12	814	454	
1018	39100	Office Furniture & Equipment			11,237	6,473	2,864	18	1,208	674	
1019	39102	Remittance Processing Equip			0	-	-	-	-	-	
1020	39103	Office Machines			0	-	-	-	-	-	
1021	39200	Transportation Equipment			0	-	-	-	-	-	
1022	39201	Trucks			0	-	-	-	-	-	
1023	39202	Trailers			0	-	-	-	-	-	
1024	39300	Stores Equipment			0	-	-	-	-	-	
1025	39400	Tools, Shop & Garage Equipment			2,649	1,526	675	4	285	159	
1026	39600	Power Operated Equipment			0	-	-	-	-	-	
1027	39603	Ditchers			0	-	-	-	-	-	
1028	39604	Backhoes			0	-	-	-	-	-	
1029	39605	Welders			0	-	-	-	-	-	
1030	39700	Communication Equipment			6,715	3,868	1,712	11	722	403	
1031	39701	Communication Equipment - Mobile Radios			0	-	-	-	-	-	
1032	39702	Communication Equipment - Fixed Radios			0	-	-	-	-	-	
1033	39705	Communication Equip. - Telemetering			0	-	-	-	-	-	
1034	39800	Miscellaneous Equipment			2,101	1,210	536	3	226	126	
1035	39900	Other Tangible Property			1,186	683	302	2	128	71	
1036	39901	Other Tangible Property - Servers - H/W			38,567	22,214	9,831	62	4,147	2,313	
1037	39902	Other Tangible Property - Servers - S/W			0	-	-	-	-	-	
1038	39903	Other Tangible Property - Network - H/W			4,009	2,309	1,022	6	431	240	
1039	39904	Other Tang. Property - CPU			0	-	-	-	-	-	
1040	39905	Other Tangible Property - MF - Hardware			0	-	-	-	-	-	
1041	39906	Other Tang. Property - PC Hardware			18,676	10,757	4,761	30	2,008	1,120	
1042	39907	Other Tang. Property - PC Software			11	7	3	0	1	1	
1043	39908	Other Tang. Property - Mainframe S/W			0	-	-	-	-	-	
1044	39909	Other Tang. Property - Application Software			402,314	231,728	102,552	645	43,264	24,125	
1045	39924	Other Tang. Property - General Startup Costs			0	-	-	-	-	-	
1046											
1047											
1048		Total General Plant			521,409	300,325	132,910	836	56,071	31,267	
1049											
1050	NTB	To Match Schedule C-1			192	111	49	0	21	12	
1051											
1052		TOTAL DEPRECIATION EXPENSE			22,028,375	13,511,899	5,469,387	31,006	1,931,114	1,084,969	

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Customer

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Taxes Other Than Income								
2									
3	Non Revenue Related:								
4	Payroll Related	7.2	Allocated O&M Expenses - Cust	23,054	18,342	4,529	8	110	66
5	Property Related	6.2	P, S, T & D Plant - Customer	4,419,838	3,532,529	850,503	1,629	21,957	13,219
6	DOT transmission User Tax	7.2	Allocated O&M Expenses - Cust	14,275	11,357	2,804	5	68	41
7	Other	7.2	Allocated O&M Expenses - Cust	27,253	21,683	5,353	10	130	78
8	Total Non Revenue Related:			4,484,419	3,583,912	863,189	1,652	22,264	13,403
9									
10	Revenue Related:								
11	State Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
12	Local Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
13	Public Service Commission Assessment	99.0	-	0	-	-	-	-	-
14	Total Revenue Related:			0	-	-	-	-	-
15									
16	Total Taxes, Other Than Income			4,484,419	3,583,912	863,189	1,652	22,264	13,403
17									
18									
19	Interest Expense	19.2	Rate Base - Cust	3,344,439	2,726,279	593,890	1,074	14,478	8,717
20									
21	Amortization of COS and Depreciation Reserves	20.2	Cost of Service - Cust	(434,546)	(348,975)	(82,003)	(156)	(2,197)	(1,215)
22									
23	Amortization of Excess ADIT	20.2	Cost of Service - Cust	(37,725)	(30,297)	(7,119)	(14)	(191)	(105)

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Demand

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
20	Taxes Other Than Income								
21									
22	Non Revenue Related:								
23	Payroll Related	7.4	Allocated O&M Expenses - Demand	48,184	26,017	16,056	-	6,111	-
24	Property Related	6.4	P, S, T & D Plant - Demand	5,032,645	2,717,393	1,677,021	-	638,231	-
25	DOT transmission User Tax	7.4	Allocated O&M Expenses - Demand	29,836	16,110	9,942	-	3,784	-
26	Other	7.4	Allocated O&M Expenses - Demand	56,961	30,756	18,981	-	7,224	-
27	Total Non Revenue Related:			5,167,627	2,790,277	1,722,001	0	655,349	0
28									
29	Revenue Related:								
30	State Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
31	Local Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
32	Public Service Commission Assessment	99.0	-	0	-	-	-	-	-
33	Total Revenue Related:			0	-	-	-	-	-
34									
35	Total Taxes, Other Than Income			5,167,627	2,790,277	1,722,001	-	655,349	-
36									
37									
38	Interest Expense	19.4	Rate Base - Demand	4,221,594	2,279,463	1,406,756	-	535,375	-
39									
40	Amortization of COS and Depreciation Reserves	20.4	Cost of Service - Demand	(541,196)	(292,305)	(180,261)	3	(68,717)	84
41									
42	Amortization of Excess ADIT	20.4	Cost of Service - Demand	(46,984)	(25,377)	(15,649)	0	(5,966)	7

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Commodity

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
39	Taxes Other Than Income								
40									
41	Non Revenue Related:								
42	Payroll Related	7.6	Allocated O&M Expenses - Comm	304,714	166,525	119,668	2,823	7,517	8,181
43	Property Related	6.6	P, S, T & D Plant - Commodity	2,933,691	884,355	629,778	18,224	671,796	729,538
44	DOT transmission User Tax	7.6	Allocated O&M Expenses - Comm	188,679	103,112	74,099	1,748	4,655	5,065
45	Other	7.6	Allocated O&M Expenses - Comm	360,218	196,858	141,466	3,337	8,887	9,671
46	Total Non Revenue Related:			3,787,302	1,350,850	965,010	26,132	692,855	752,455
47									
48	Revenue Related:								
49	State Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
50	Local Gross Receipts - Tax	99.0	-	0	-	-	-	-	-
51	Public Service Commission Assessment	1.0	Mcf	291,875	85,778	61,643	1,836	68,270	74,350
52	Total Revenue Related:			291,875	85,778	61,643	1,836	68,270	74,350
53									
54	Total Taxes, Other Than Income			4,079,177	1,436,627	1,026,653	27,968	761,125	826,804
55									
56									
57	Interest Expense	19.6	Rate Base - Comm	2,674,317	786,856	560,567	16,415	628,156	682,323
58									
59	Amortization of COS and Depreciation Reserves	20.6	Cost of Service - Comm	(1,212,775)	(601,961)	(432,130)	(10,481)	(80,604)	(87,599)
60									
61	Amortization of Excess ADIT	20.6	Cost of Service - Comm	(105,288)	(52,260)	(37,516)	(910)	(6,998)	(7,605)

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF TAXES, OTHER THAN INCOME & NET DEDUCTIONS FOR INCOME TAX

Total Taxes Other

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
58	Taxes Other Than Income								
59									
60	Non Revenue Related:								
61	Payroll Related			375,952	210,884	140,253	2,831	13,738	8,246
62	Property Related			12,386,174	7,134,278	3,157,302	19,853	1,331,984	742,757
63	DOT transmission User Tax			232,790	130,580	86,845	1,753	8,506	5,106
64	Other			444,432	249,297	165,800	3,347	16,240	9,748
65	Total Non Revenue Related:			13,439,348	7,725,039	3,550,200	27,784	1,370,467	765,858
66									
67	Revenue Related:								
68	State Gross Receipts - Tax			0	-	-	-	-	-
69	Con Local Gross Receipts - Tax			0	-	-	-	-	-
70	Public Service Commission Assessment			291,875	85,778	61,643	1,836	68,270	74,350
71	Total Revenue Related:			291,875	85,778	61,643	1,836	68,270	74,350
72									
73	Total Taxes, Other Than Income			13,731,224	7,810,816	3,611,843	29,620	1,438,737	840,207
74									
75									
76	Interest Expense			10,240,350	5,792,599	2,561,213	17,489	1,178,010	691,040
77									
78	Amortization of COS and Depreciation Reserves			(2,188,517)	(1,243,241)	(694,394)	(10,635)	(151,518)	(88,729)
79									
80	Amortization of Excess ADIT			(189,998)	(107,933)	(60,284)	(923)	(13,154)	(7,703)

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION OF REVENUES

Total Revenues

Line No.		Allocation Factor	Allocation Basis	Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
1	Rate Schedule Revenue:								
2									
3	Base Revenues	Input		96,636,506	52,550,517	26,407,052	226,254	9,273,095	8,179,588
4	Base Revenue Increase	Input		0	-	-	-	-	-
5	Gas Costs	Input		87,640,898	50,501,238	36,296,543	843,117	-	-
6	Rider FF and Rider Tax	Input		0	-	-	-	-	-
7									
8	Total Rate Schedule Revenue			184,277,404	103,051,755	62,703,595	1,069,371	9,273,095	8,179,588
9									
10	Other Revenue:								
11									
12	Forfeited Discounts	18.6	Total Rate Schedule Revenues	367,462	205,492	125,035	2,132	18,491	16,311
13	Misc. Service Revenues	18.6	Total Rate Schedule Revenues	58,912	32,945	20,046	342	2,965	2,615
14	NTB	18.2	Base Revenues	(5)	(2)	(1)	(0)	(0)	(0)
15	Other Gas Revenue	18.2	Base Revenues	3,118,240	1,695,685	852,095	7,301	299,222	263,937
16									
17	Total Non-Rate Revenue			3,544,609	1,934,120	997,175	9,775	320,677	282,862
18									
19	TOTAL REVENUE			187,822,013	104,985,875	63,700,770	1,079,146	9,593,772	8,462,450

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

CLASSIFICATION FACTORS

			Total Company	Customer	Demand	Commodity
	Input	Values	1	1	0	0
1.0	Customer	%	100.0000%	100.0000%	0.0000%	0.0000%
	Input	Values	1	0	1	0
2.0	Demand	%	100.0000%	0.0000%	100.0000%	0.0000%
	Input	Values	1	0	0	1
3.0	Commodity	%	100.0000%	0.0000%	0.0000%	100.0000%
	Input	Values	100	0	50	50
3.5	Storage (50/50)	%	100.0000%	0.0000%	50.0000%	50.0000%
	Input	Values	1	-	0.62	0.38
4.0	Mains (Peak and Average)	%	100.0000%	0.0000%	61.7207%	38.2793%
	Internally Generated	Values	549,923,660	155,087,701	243,695,525	151,140,434
4.1	Mains & Services	%	100.0000%	28.2017%	44.3144%	27.4839%
	Internally Generated	Values	901,469,328	321,677,069	366,277,397	213,514,863
5.4	P, S, T & D Plant	%	100.0000%	35.6836%	40.6312%	23.6852%
	Internally Generated	Values	733,894,161	242,111,038	304,840,252	186,942,870
5.7	Net Plant	%	100.0000%	32.9899%	41.5374%	25.4727%
	Internally Generated	Values	120,959,622	7,417,382	15,502,949	98,039,291
9.1	Allocated O&M Expenses	%	100.0000%	6.1321%	12.8166%	81.0513%
	Internally Generated	Values	9,527,418	939,386	5,131,869	3,456,163
10.0	Composite of Accts. 871-879 & 886-893	%	100.0000%	9.8598%	53.8642%	36.2760%
	Internally Generated	Values	431,755,369	-	266,482,444	165,272,925
12.0	Composite of Accts. 374-379	%	100.0000%	0.0000%	61.7207%	38.2793%
	Internally Generated	Values	628,233,491	205,177,426	258,989,835	164,066,229
13.0	Rate Base	%	100.0000%	32.6594%	41.2251%	26.1155%
	Internally Generated	Values	12,945,100	2,357,025	6,327,016	4,261,059
17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	%	100.0000%	18.2079%	48.8758%	32.9164%
	Internally Generated	Values	223,201,833	44,318,316	55,195,353	123,688,164
18.0	Total Cost of Service at Equalized ROR	%	100.0000%	19.8557%	24.7289%	55.4154%
		Values	0	0	0	0
99.0	-	%	0.0000%	0.0000%	0.0000%	0.0000%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION FACTORS

			Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
	Input	Value	33,818,064	9,938,593	7,142,201	212,715	7,910,070	8,614,485
1.0	Mcf	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	17,293,508	9,938,593	7,142,201	212,715	-	-
1.2	Sales Mcf	%	100.0000%	57.4701%	41.2999%	1.2300%	0.0000%	0.0000%
	Input	Value	20,198,212	7,673,367	5,064,215	109,105	3,597,159	3,754,366
1.5	Winter Volumes	%	100.0000%	37.9903%	25.0726%	0.5402%	17.8093%	18.5876%
	Input	Value	2,169,218	1,925,523	241,323	105	1,415	852
2.0	Bills	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	243,695	0	241,323	105	1,415	852
2.2	Non-Residential Bills	%	100.0000%	0.0000%	99.0266%	0.0431%	0.5807%	0.3496%
	Input	Value	242,043	130,692	80,656	0	30,695	0
3.0	Peak Day	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Input	Value	85,443,836	59,490,553	24,265,293	74,716	1,007,003	606,271
4.0	Meter Investment	%	100.0000%	69.6253%	28.3991%	0.0874%	1.1786%	0.7096%
	Input	Value	1	1	-	-	-	-
4.2	Direct to Residential	%	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Input	Value	1	-	1	-	-	-
4.4	Direct to Non-Res Sales Firm	%	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
	Input	Value	1	-	-	1	-	-
4.6	Direct to Non-Res Sales Interruptible	%	100.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
	Input	Value	1	-	-	-	1	-
4.8	Direct to Transport Firm	%	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
	Input	Value	1	-	-	-	-	1
5.0	Direct to Transport Interruptible	%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Internally Generated	Value	901,469,328	519,234,799	229,789,389	1,444,892	96,942,158	54,058,090
6.0	P, S, T & D Plant	%	100.0000%	57.5987%	25.4905%	0.1603%	10.7538%	5.9967%
	Internally Generated	Value	321,677,069	257,098,521	61,899,891	118,567	1,598,004	962,086
6.2	P, S, T & D Plant - Customer	%	100.0000%	79.9244%	19.2429%	0.0369%	0.4968%	0.2991%
	Internally Generated	Value	366,277,397	197,772,683	122,054,084	0	46,450,630	0
6.4	P, S, T & D Plant - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	213,514,863	64,363,596	45,835,414	1,326,325	48,893,524	53,096,004
6.6	P, S, T & D Plant - Commodity	%	100.0000%	30.1448%	21.4671%	0.6212%	22.8994%	24.8676%
	Internally Generated	Value	120,959,622	67,850,323	45,125,285	910,909	4,419,948	2,653,157
7.0	Allocated O&M Expenses	%	100.0000%	56.0934%	37.3061%	0.7531%	3.6541%	2.1934%
	Internally Generated	Value	7,417,382	5,901,377	1,457,017	2,602	35,271	21,115
7.2	Allocated O&M Expenses - Cust	%	100.0000%	79.5615%	19.6433%	0.0351%	0.4755%	0.2847%
	Internally Generated	Value	15,502,949	8,370,868	5,166,025	0	1,966,056	0
7.4	Allocated O&M Expenses - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	98,039,291	53,578,078	38,502,243	908,306	2,418,621	2,632,042
7.6	Allocated O&M Expenses - Comm	%	100.0000%	54.6496%	39.2723%	0.9265%	2.4670%	2.6847%
	Input	Value	1,173,349	795,796	377,232	0	321	0
8.0	Customer Deposit Balances	%	100.0000%	67.8227%	32.1500%	0.0000%	0.0273%	0.0000%
	Internally Generated	Value	733,894,161	418,315,704	184,631,022	1,239,360	82,547,828	47,160,246
9.0	Allocated Net Plant	%	100.0000%	56.9995%	25.1577%	0.1689%	11.2479%	6.4260%
	Internally Generated	Value	242,111,038	197,416,206	42,942,963	77,544	1,045,111	629,214
9.2	Allocated Net Plant - Cust	%	100.0000%	81.5395%	17.7369%	0.0320%	0.4317%	0.2599%
	Internally Generated	Value	304,840,252	164,599,495	101,581,474	0	38,659,283	0
9.4	Allocated Net Plant - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	186,942,870	56,300,003	40,106,585	1,161,816	42,843,434	46,531,032
9.6	Allocated Net Plant - Comm	%	100.0000%	30.1162%	21.4539%	0.6215%	22.9179%	24.8905%
	Internally Generated	Value	9,527,418	4,440,323	2,707,206	22,560	1,470,278	887,051
10.0	Composite of Accts. 871-879 & 886-893	%	100.0000%	46.6057%	28.4149%	0.2368%	15.4321%	9.3105%
	Internally Generated	Value	939,386	653,642	267,197	821	11,064	6,661
10.2	Composite of Accts. 871-879 & 886-893 - Cust	%	100.0000%	69.5818%	28.4438%	0.0874%	1.1778%	0.7091%
	Internally Generated	Value	5,131,869	2,770,970	1,710,085	0	650,814	0
10.4	Composite of Accts. 871-879 & 886-893 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	3,456,163	1,015,711	729,924	21,739	808,399	880,389
10.6	Composite of Accts. 871-879 & 886-893 - Comm	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	549,923,660	313,666,754	130,379,714	958,175	66,358,057	38,560,961
11.0	Composite of Accts. 376 & 380	%	100.0000%	57.0382%	23.7087%	0.1742%	12.0668%	7.0121%
	Internally Generated	Value	155,087,701	137,664,778	17,253,327	7,507	101,176	60,914
11.2	Composite of Accts. 376 & 380 - Cust	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	243,695,525	131,584,198	81,206,305	0	30,905,021	0
11.4	Composite of Accts. 376 & 380 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	151,140,434	44,417,778	31,920,082	950,668	35,351,860	38,500,047
11.6	Composite of Accts. 376 & 380 - Comm	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%

Atmos Energy Corporation, Kentucky/Mid-States Division
Class Cost of Service - Energy/Demand Study
Forecasted Test Period: Twelve Months Ended March 31, 2026

ALLOCATION FACTORS

			Total Company	Residential Sales	Non-Res Sales Firm	Non-Res Sales Interruptible	Transport Firm	Transport Interruptible
	Internally Generated	Value	431,755,369	192,459,163	123,704,348	1,039,561	72,452,276	42,100,021
12.0	Composite of Accts. 374-379	%	100.0000%	44.5760%	28.6515%	0.2408%	16.7809%	9.7509%
	Internally Generated	Value	0	0	0	0	0	0
12.2	Composite of Accts. 374-379 - Cust	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	266,482,444	143,888,070	88,799,557	0	33,794,816	0
12.4	Composite of Accts. 374-379 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	165,272,925	48,571,093	34,904,791	1,039,561	38,657,460	42,100,021
12.6	Composite of Accts. 374-379 - Comm	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	74,469,926	51,849,932	21,148,799	65,120	877,669	528,405
13.0	Composite of Accts. 381-383	%	100.0000%	69.6253%	28.3991%	0.0874%	1.1786%	0.7096%
	Internally Generated	Value	74,469,926	51,849,932	21,148,799	65,120	877,669	528,405
13.2	Composite of Accts. 381-383 - Cust	%	100.0000%	69.6253%	28.3991%	0.0874%	1.1786%	0.7096%
	Internally Generated	Value	0	0	0	0	0	0
13.4	Composite of Accts. 381-383 - Demand	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
13.6	Composite of Accts. 381-383 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	155,087,701	137,664,778	17,253,327	7,507	101,176	60,914
14.0	Account 380	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	155,087,701	137,664,778	17,253,327	7,507	101,176	60,914
14.2	Account 380 - Cust	%	100.0000%	88.7658%	11.1249%	0.0048%	0.0652%	0.0393%
	Internally Generated	Value	0	0	0	0	0	0
14.4	Account 380 - Demand	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	0	0	0	0	0	0
14.6	Account 380 - Comm	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Internally Generated	Value	12,945,100	6,538,602	3,471,053	27,872	1,813,469	1,094,104
17.0	Composite of Accts. 870-902, 905-916, 924 & 928-930.1	%	100.0000%	50.5102%	26.8136%	0.2153%	14.0089%	8.4519%
	Internally Generated	Value	2,357,025	1,870,051	462,797	1,070	14,423	8,684
17.2	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Cust	%	100.0000%	79.3395%	19.6348%	0.0454%	0.6119%	0.3684%
	Internally Generated	Value	6,327,016	3,416,293	2,108,342	0	802,381	0
17.4	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	4,261,059	1,252,258	899,914	26,802	996,665	1,085,421
17.6	Composite of Accts. 870-902, 905-916, 924 & 928-930.1 - Comm	%	100.0000%	29.3884%	21.1195%	0.6290%	23.3901%	25.4730%
	Internally Generated	Value	187,822,013	104,985,875	63,700,770	1,079,146	9,593,772	8,462,450
18.0	Revenues	%	100.0000%	55.8965%	33.9155%	0.5746%	5.1079%	4.5056%
	Internally Generated	Value	96,636,506	52,550,517	26,407,052	226,254	9,273,095	8,179,588
18.2	Base Revenues	%	100.0000%	54.3796%	27.3262%	0.2341%	9.5959%	8.4643%
	Internally Generated	Value	87,640,898	50,501,238	36,296,543	843,117	-	-
18.4	Gas Costs	%	100.0000%	57.6229%	41.4151%	0.9620%	0.0000%	0.0000%
	Internally Generated	Value	184,277,404	103,051,755	62,703,595	1,069,371	9,273,095	8,179,588
18.6	Total Rate Schedule Revenues	%	100.0000%	55.9221%	34.0267%	0.5803%	5.0321%	4.4387%
	Internally Generated	Value	628,233,491	355,369,153	157,127,414	1,072,923	72,269,502	42,394,499
19.0	Rate Base	%	100.0000%	56.5664%	25.0110%	0.1708%	11.5036%	6.7482%
	Internally Generated	Value	205,177,426	167,254,050	36,434,468	65,905	888,233	534,770
19.2	Rate Base - Cust	%	100.0000%	81.5168%	17.7575%	0.0321%	0.4329%	0.2606%
	Internally Generated	Value	258,989,835	139,842,412	86,302,806	0	32,844,617	0
19.4	Rate Base - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	164,066,229	48,272,691	34,390,140	1,007,019	38,536,651	41,859,728
19.6	Rate Base - Comm	%	100.0000%	29.4227%	20.9611%	0.6138%	23.4885%	25.5139%
	Internally Generated	Value	223,201,833	126,795,249	70,819,662	1,084,605	15,453,017	9,049,300
20.0	Cost of Service	%	100.0000%	56.8074%	31.7290%	0.4859%	6.9233%	4.0543%
	Internally Generated	Value	44,318,316	35,591,119	8,363,289	15,902	224,100	123,907
20.2	Cost of Service - Cust	%	100.0000%	80.3079%	18.8710%	0.0359%	0.5057%	0.2796%
	Internally Generated	Value	55,195,353	29,811,494	18,384,402	(263)	7,008,322	(8,603)
20.4	Cost of Service - Demand	%	100.0000%	54.0109%	33.3079%	-0.0005%	12.6973%	-0.0156%
	Internally Generated	Value	123,688,164	61,392,636	44,071,971	1,068,966	8,220,595	8,933,996
20.6	Cost of Service - Comm	%	100.0000%	49.6350%	35.6315%	0.8642%	6.6462%	7.2230%
	Internally Generated	Value	216,905,276	129,332,607	57,732,877	284,599	19,699,188	9,856,005
21.0	Depreciation Reserve	%	100.0000%	59.6263%	26.6166%	0.1312%	9.0819%	4.5439%
	Internally Generated	Value	97,168,809	73,751,233	22,344,207	47,511	640,339	385,519
21.2	Depreciation Reserve - Cust	%	100.0000%	75.9001%	22.9952%	0.0489%	0.6590%	0.3968%
	Internally Generated	Value	81,480,537	43,995,683	27,151,641	0	10,333,213	0
21.4	Depreciation Reserve - Demand	%	100.0000%	53.9953%	33.3229%	0.0000%	12.6818%	0.0000%
	Internally Generated	Value	38,255,930	11,585,691	8,237,029	237,088	8,725,636	9,470,486
21.6	Depreciation Reserve - Comm	%	100.0000%	30.2847%	21.5314%	0.6197%	22.8086%	24.7556%
		Value	0	0	0	0	0	0
99.0	-	%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

SUMMARY OF ALTERNATIVE CLASS COST OF SERVICE STUDIES

Customer/Demand Study

Line No.		Return at Present Rates	Relative Return at Present Rates	Revenue Deficiency at Equalized Proposed Return	Allocation of Amortization of Excess ADIT	Allocation of Amortization of COS and Depreciation Reserves	Revenue Increase at Equalized Proposed Return	Calculated Fixed Costs (Dollars/Customer/Month)
1	Total Company	4.12%	1.00	$ 35,379,820	$ (189,998)	$ (2,188,517)	$ 33,001,305	$ 60.31
2	Residential Sales	0.94%	0.23	$ 46,568,287	$ (129,003)	$ (1,485,937)	$ 44,953,347	$ 51.60
3	Non-Residential Firm Sales	8.22%	2.00	$ 127,211	$ (54,335)	$ (625,863)	$ (552,987)	$ 109.28
4	Non-Residential Interruptible Sales	91.90%	22.29	$ (191,019)	$ (756)	$ (8,709)	$ (200,483)	$ 154.34
5	Firm Transport	17.93%	4.35	$ (3,679,318)	$ (5,036)	$ (58,010)	$ (3,742,364)	$ 3,547.63
6	Interruptible Transport	109.54%	26.57	$ (7,445,341)	$ (868)	$ (9,999)	$ (7,456,208)	$ 73.75

Demand-Only Study

		Return at Present Rates	Relative Return at Present Rates	Revenue Deficiency at Equalized Proposed Return	Allocation of Amortization of Excess ADIT	Allocation of Amortization of COS and Depreciation Reserves	Revenue Increase at Equalized Proposed Return	Calculated Fixed Costs (Dollars/Customer/Month)
7	Total Company	4.12%	1.00	$ 35,379,820	$ (189,998)	$ (2,188,517)	$ 33,001,305	$ 60.31
8	Residential Sales	2.69%	0.65	$ 29,587,162	$ (114,551)	$ (1,309,416)	$ 28,163,195	$ 42.78
9	Non-Residential Firm Sales	3.65%	0.88	$ 10,968,218	$ (63,561)	$ (731,006)	$ 10,173,652	$ 154.19
10	Non-Residential Interruptible Sales	98.74%	23.95	$ (193,383)	$ (754)	$ (8,686)	$ (202,822)	$ 131.83
11	Firm Transport	5.05%	1.23	$ 2,482,345	$ (10,280)	$ (129,599)	$ 2,342,466	$ 7,900.57
12	Interruptible Transport	111.47%	27.04	$ (7,464,523)	$ (852)	$ (9,811)	$ (7,475,186)	$ 51.24

Energy/Demand Study

		Return at Present Rates	Relative Return at Present Rates	Revenue Deficiency at Equalized Proposed Return	Allocation of Amortization of Excess ADIT	Allocation of Amortization of COS and Depreciation Reserves	Revenue Increase at Equalized Proposed Return	Calculated Fixed Costs (Dollars/Customer/Month)
13	Total Company	4.12%	1.00	$ 35,379,820	$ (189,998)	$ (2,188,517)	$ 33,001,305	$ 45.88
14	Residential Sales	3.75%	0.91	$ 21,814,810	$ (107,933)	$ (1,243,241)	$ 20,463,636	$ 33.97
15	Non-Residential Firm Sales	4.94%	1.20	$ 7,113,656	$ (60,284)	$ (694,394)	$ 6,358,977	$ 110.84
16	Non-Residential Interruptible Sales	7.93%	1.92	$ 5,293	$ (923)	$ (10,635)	$ (6,265)	$ 148.95
17	Firm Transport	2.28%	0.55	$ 5,864,661	$ (13,154)	$ (151,518)	$ 5,699,988	$ 5,110.70
18	Interruptible Transport	7.28%	1.77	$ 581,401	$ (7,703)	$ (88,729)	$ 484,968	$ 135.33

SUMMARY OF ALTERNATIVE CLASS COST OF SERVICE STUDIES

Revenue Deficiency at Equalized Proposed Return

Line No.		Minimum Revenue Increase Indicated	Maximum Revenue Increase Indicated	Average Revenue Increase Indicated	Proposed Revenue Increase
1	Total Company	$ 33,001,305	$ 33,001,305	$ 33,001,305	$ 33,001,164
2	Residential Sales	$ 20,463,636	$ 44,953,347	$ 31,193,393	$ 18,487,878
3	Non-Residential Firm Sales	$ (552,987)	$ 10,173,652	$ 5,326,547	$ 7,281,586
4	Non-Residential Interruptible Sales	$ (202,822)	$ (6,265)	$ (136,524)	$ 79,307
5	Firm Transport	$ (3,742,364)	$ 5,699,988	$ 1,433,363	$ 4,285,098
6	Interruptible Transport	$ (7,475,186)	$ 484,968	$ (4,815,475)	$ 2,867,295

Calculated Customer Costs at Equalized Proposed Return

		Minimum Customer-Related Cost Indicated	Maximum Customer-Related Cost Indicated	Average Customer-Related Cost Indicated	Proposed Customer-Related Cost
7	Total Company	$ 45.88	$ 60.31	$ 55.50	$ -
8	Residential Sales	$ 33.97	$ 51.60	$ 42.78	$ 25.00
9	Non-Residential Firm Sales	$ 109.28	$ 154.19	$ 124.77	$ 75.00
10	Non-Residential Interruptible Sales	$ 131.83	$ 154.34	$ 145.04	$ 685.00
11	Firm Transport	$ 3,547.63	$ 7,900.57	$ 5,519.63	$ 685.00
12	Interruptible Transport	$ 51.24	$ 135.33	$ 86.77	$ 685.00

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

TESTIMONY OF JOEL J. MULTER

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OF JOEL J. MULTER, WITNESS FOR
ATMOS ENERGY CORPORATION

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EXHIBITS

Exhibit JJM-1 – NOLC Asset Kentucky

Exhibit JJM-2 – Remaining Book Life for Protected EDIT Amortization

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joel J. Multer. My business address is 5430 LBJ Freeway, Dallas, Texas 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Vice President of Tax for Atmos Energy Corporation.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Business Administration Degree in Accounting as well as a Master of Science with a focus on Taxation from the University of Wisconsin-Milwaukee. I joined Atmos Energy in my current role in August 2021. Prior to that time, I held positions in both public accounting and within the private sector, including over thirteen years in the regulated utility industry. My previous employers include American Electric Power Service Corporation, Ernst & Young, WEC Energy Group, and Walgreens Boots Alliance.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony to the Kentucky Public Service Commission ("Commission") for Atmos Energy in Case Nos. 2021-00214 and 2023-00231. I have also provided testimony to the Arkansas Public Service Commission, the Louisiana Public Service Commission, and the Public Utility Commission of Texas on behalf of Southwestern Electric Power Company. I have also provided testimony to the Oklahoma Corporation Commission on behalf of Public Service Company

of Oklahoma, to the Michigan Public Service Commission on behalf of Indiana Michigan Power Company, and to the Public Utilities Commission of Ohio on behalf of the Ohio Power Company.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to address the following elements of the Company's filing –

- Determination of Federal and State Income Tax Expense
- Accumulated deferred income taxes ("ADIT") associated with net operating loss carryforwards ("NOLC-ADIT"), specifically the Commission's findings in Case No. 2021-00214 and how the Company has complied with the Commission's order in this filing.
- Amortization of Excess Deferred Income Taxes ("EDIT") resulting from the 2017 Tax Cuts and Jobs Act
- Proposal of Tax Rider to capture the effects of the 2022 Inflation Reduction Act, signed into law as Public Law 117-169, 136 STAT. 1818 on August 16, 2022, (also referred to as "Tax Act 2022" throughout the Company's filing) as well as any future changes to the federal or state income tax rate and other federal, state or local tax law changes, including but not limited to property tax rates.

III. INCOME TAXES

Q. HOW IS TAX EXPENSE CALCULATED IN THE CURRENT FILING?

A. Tax expense is calculated by applying statutory tax rates to the forecasted return to arrive at required operating income, as shown on Schedule E (FR16(8)(e)).

Q. WHAT ARE THE STATUTORY INCOME TAX RATES UTILIZED BY THE COMPANY IN THIS CASE?

A. The Company's current and proposed rates reflect a 21% federal statutory tax rate and a 5% State of Kentucky income tax rates. Because state income taxes are deductible for federal income tax purposes, the combined federal and state income tax rate is 24.95%.

Q. IS THIS CALCUATION CONSISTENT WITH THAT IN THE COMPANY'S PREVIOUS RATE CASE FILINGS?

A. Yes it is.

IV. NOLC ADIT

Q. CAN YOU SUMMARIZE THE COMMISSION'S FINDINGS IN CASE NO. 2021-00214 WITH REGARD TO NOLC ADIT?

A. Yes. In Case No. 2021-00214, the Commission considered the Company's historic manner of tracking and allocating NOLC ADIT associated with its regulatory operations to its various operating divisions. Specifically, the Commission ordered that "in future applications to increase base rates, Atmos Kentucky must file a report showing the generation and utilization of NOLC ADIT for Kentucky since this Order based on the expenses incurred and revenue generated from Kentucky

operations."[1] Additionally, the Order provided that if Atmos Kentucky proposes to use a different method to reflect the generation and utilization of NOLC ADIT for Kentucky in its revenue model that it needs to explain in detail why using that method would be reasonable.[2]

Q. HOW ARE ADIT AND NOLC-RELATED DEFERRED TAXES PRESENTED IN THIS FILING?

A. The Company has complied with the Commission's order in Case No. 2021-00214. See attached Exhibit JJM-1 NOLC Asset Kentucky showing the generation and utilization of NOLC ADIT for Kentucky since the order in Case No. 2021-00214 based on the expenses incurred and revenue generated from Kentucky operations.

Q. IN ADDITION TO INCLUDING THE COMPANY'S NOLC ADIT SPECIFIC TO KENTUCKY OPERATIONS, HAVE YOU FORECASTED PLANT RELATED ADIT FOR THE TEST PERIOD IN THIS CASE?

A. Yes. I have forecasted plant related ADIT using the plant additions and book depreciation forecasts provided by Company witness Gregory K. Waller. The forecast of ADIT is done consistent with Internal Revenue Code ("IRC") regulations for forward-looking test years.

V. EXCESS DEFERRED INCOME TAX ("EDIT") AMORTIZATION

Q. HOW ARE EXCESS DEFERRED INCOME TAXES ("EDIT") CURRENTLY BEING AMORTIZED WITHIN BASE RATES?

A. The Commission in Docket No. 2021-00214 ordered that the remaining balance of

[1] Case No. 2021-00214, Electronic Application of Atmos Energy Corporation for an Adjustment of Rates (Ky. PSC May 19, 2022) final Order at 14.
[2] *Id*.

unprotected EDIT be refunded over a 3-year period and protected EDIT continue to be amortized over a 22-year period consistent with the remaining book life of the underlying assets.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO EDIT AMORTIZATION WITHIN THIS FILING?

A. Yes, the Company is proposing two changes in this filing. First, the Company's unprotected EDIT liability is scheduled to be fully amortized at the end of May 2025. Because this falls two months after the proposed effective date of new rates in this proceeding, the Company has proposed to refund the final two months of the amortization as a one-time bill credit and has included no unprotected EDIT amortization in its proposed rates consistent with that proposal. In Additional to the unprotected EDIT liability change, the Company has redetermined its amortization expense associated with protected EDIT to comply with the normalization requirements of the IRC. More specifically, the Company has recalculated its remaining book life to exclude cost of removal expense from total financial statement depreciation expense to comply with the conclusion of Private Letter Ruling 202211004.[3] The exclusion of cost of removal expense results in an average remaining book life of 27 years. The result is a decrease in annual and monthly protected EDIT amortization from that currently in rates of $62,983 and $5,249, respectively. See Exhibit JJM-2 Remaining Book Life for Protected EDIT Amortization.

[3] Private Letter Ruling 2211004 was published after the conclusion of Case No. 2021-00214.

VI. TAX RIDER TARIFF

Q. WHY IS THE COMPANY PROPOSING THE ESTABLISHMENT OF THE "TAX RIDERTARIFF?"

A. The Tax Rider Tariff is designed to capture and implement the income tax effects of the Tax Act 2022 as well as the effects of any future changes to the federal or state income tax rate and other federal, state or local tax law changes, including but not limited to property tax rates. Establishment of the proposed tariff will allow customer rates to be aligned with the Company's costs in a timely manner and that the procedure for achieving that alignment is seamless, efficient and transparent. While the primary impetus for the request to establish the tariff is the Tax Act 2022, the proposed tariff is designed to efficiently capture the impact of it and other future changes to tax law that could result in a misalignment of rates and costs and alleviate the misalignment in a timely and efficient manner. Because tax law changes are inherently unpredictable and largely out of the Company's and the Commission's control, the proposed language is the most effective way to reflect their impact in the customer's rates.

Q. PLEASE DESCRIBE THE TAX ACT 2022.

A. The Tax Act 2022 was signed into law on August 16, 2022, and introduced a new 15% corporate alternative minimum tax ("CAMT") and expanded various energy-related federal income tax credit provisions.

Q. PLEASE DESCRIBE THE NEW CAMT AND HOW IT OPERATES.

A The CAMT applies to any corporation having three-year average annual adjusted financial statement income greater than $1 billion. If applicable, the corporation is

required to calculate a minimum tax liability that is equal to 15% of adjusted financial statement income ("AFSI"). AFSI generally consists of the corporation's net income or loss as reported on its annual financial statements prepared under U.S. Generally Accepted Accounting Principles adjusted to exclude income tax expense and substitute tax depreciation in place of financial statement depreciation expense.

The corporation will owe the minimum tax liability to the extent it is greater than its regular tax liability (federally determined taxable income multiplied by the 21% corporate tax rate). Any amount of minimum tax liability paid in excess of the regular tax results in a tax credit that can be carried forward indefinitely to future tax periods and used to offset regular tax liability to the extent it is greater than that period's minimum tax liability. This CAMT tax credit carryforward, therefore, represents incremental income taxes paid due to the CAMT and is accounted for as a deferred tax asset within the corporation's financial statements.

Q. IS THE COMPANY CURRENTLY SUBJECT TO THE CAMT?

A. No.

Q. DOES THE COMPANY EXPECT TO PAY THE CAMT IN THE FUTURE?

A. Yes. The Company currently projects to begin paying the CAMT quarterly beginning in its 2027 fiscal year.

Q. PLEASE FURTHER EXPLAIN THE FINANCIAL STATEMENT TREATMENT FOR THE CAMT.

A. A current federal income tax liability and a current federal income tax expense will be recorded for the CAMT liability. When the minimum tax is paid, a CAMT credit

is generated, which can be carried forward indefinitely to offset future regular federal income tax liabilities in periods where the regular federal income tax liability exceeds the CAMT liability. The CAMT credit cannot be carried back to previous taxable years. A federal deferred tax asset and a federal deferred tax benefit are recognized for the CAMT credit carryforward. When the CAMT credit carryforward is used to offset regular taxable income, the deferred tax asset will reverse and the current tax liability will be reduced. Total income tax expense is unaffected since the CAMT is not designed to increase the total amount of taxes paid over the life of a corporation, but instead to accelerate the payment of those taxes to an earlier period.

Q. PLEASE EXPLAIN THE IMPACT OF THE CAMT TO CASHFLOW.

A. Payment of the CAMT, once applicable to the Company, means that the Company will no longer be able to defer a portion of taxes to future periods. The cost-free capital previously received from government incentives to invest is no longer available. Thus, the resulting deferred tax asset represents a new financing requirement for the Company in addition to the financing that is required to fund infrastructure investments. It is for this reason that it is appropriate for the Company to collect a return on the CAMT asset and the reason that the proposed tariff language is necessary.

Q. HOW DOES THE TARIFF REFLECT THE IMPACT OF CAMT IN RATES?

A. The tariff prescribes the calculation of a rider calculated as the product of the Company's grossed-up rate of return authorized in the Company's most recent base

rate case proceeding times the CAMT deferred tax asset estimated at September 30 of the fiscal year or applicable quarter-end within a fiscal year prior to the annual change in the rates pursuant to the tariff, less the income tax credits received in accordance with Internal Revenue Code requirements applicable to the Tax Act 2022 grossed-up for income taxes to a revenue equivalent. Furthermore, the estimated CAMT deferred tax asset and the related effects on the rider revenue requirements shall be trued up to the actual effects in the following year and the over/under recovery amortized over the twelve months that each year's recalculated tariff rates are in effect.

Q. PLEASE DESCRIBE THE PURPOSE OF THE SECOND SECTION OF THE PROPOSED TARIFF, "OTHER FEDERAL OR STATE TAX RATE CHANGES".

A. The purpose of the second section of the proposed tariff, like that of the first section, is to align customer's rates with any future federal and state tax rate changes in a timely manner.

Q. PLEASE DESCRIBE THE MECHANISMS BY WHICH THE PROPOSED TARIFF ACCOMPLISHES THIS PURPOSE.

A. The proposed tariff prescribes that the Company 1) accrue regulatory assets and/or liabilities as applicable as of the effective date of the federal state, or local tax rate change; and 2) refund or collect applicable amounts to/from customers within twelve (12) months or as subject to applicable Internal Revenue Code rules and regulations of a Commission decision issued pursuant to a filing made pursuant to the tariff.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Joel J. Multer, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Joel J. Multer

STATE OF TEXAS

COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Joel J. Multer on this the 26th day of September, 2024.

AMANDA MORGAN
Notary Public, State of Texas
Comm. Expires 07-12-2027
Notary ID 13208523-2

Notary Public

My Commission Expires: July 12, 2027

Atmos Enery Corporation
NOLC Asset Kentucky
FY 2022 - FY 2024 Q3 (June 2024)

		FY 2022	FY 2023	As of 6/30/2024 FY 2024
DIV 09	**Pre Tax Book Income**	**27,826,385**	**32,545,724**	**30,045,584**
DIV 09	Federal Taxable Income (Loss) from Book/Tax Differences	(51,090,545)	(8,033,323)	(21,012,802)
DIV 02	Federal Taxable Income (Loss) from Book/Tax Differences	(18,026,132)	(9,024,826)	(108,093)
DIV 012	Federal Taxable Income (Loss) from Book/Tax Differences	155,935	433,981	290,790
DIV 091	Federal Taxable Income (Loss) from Book/Tax Differences	2,362,331	(4,907,832)	(8,629,366)
	Regulatory Federal Taxable Income (Loss)	(38,772,027)	11,013,723	586,113
	Federal Tax Rate	21.00%	21.00%	21.00%
	Increase / (Decrease) in NOLC ADIT Asset	**8,142,126**	**(2,312,882)**	**(123,084)**
	NOLC ADIT Beginning of Year	**28,552,909** A	**36,695,035**	**34,382,153**
	Increase / (Decrease) in NOLC ADIT Asset	**8,142,126**	**(2,312,882)**	**(123,084)**
	NOLC ADIT End of Year	**36,695,035**	**34,382,153**	**34,259,069**

A - NOL ADIT as of 9/30/2021 - End of Base Period in Case No. 2021-00214

Atmos Enery Corporation
NOLC Asset Kentucky
FY 2022 - FY 2024 Q3 (June 2024)

				As of 6/30/2024
DIV 09		**FY 2022**	**FY 2023**	**FY 2024**
	Pre Tax Book Income	**27,826,385**	**32,545,724**	**30,045,584**
	ADIT Beginning of Year	(97,066,594)	(120,107,365)	(119,965,923)
	Less Items Excluded from Rate Base	(1,439,654)	(5,485,739)	(1,437,843)
	Less State Only Items	11,070,567	5,705,377	5,782,479
	Less TCJA Regulatory Liabiltiy related ADIT	7,021,267	6,138,862	4,159,620
	Adjusted ADIT Beginning of Year	(113,718,774)	(126,465,865)	(128,470,179)
	ADIT End of Year	(120,107,365)	(119,965,923)	(126,931,020)
	Less Items Excluded from Rate Base	(5,485,739)	(1,437,843)	(1,011,179)
	Less State Only Items	5,705,377	5,782,479	5,117,842
	Less TCJA Regulatory Liabiltiy related ADIT	6,138,862	4,159,620	2,675,190
	Adjusted ADIT End of Year	(126,465,865)	(128,470,179)	(133,712,873)
	Change in Adjusted ADIT	(12,747,091)	(2,004,314)	(5,242,694)
	Applicable Federal & State Deferred Tax Rate	24.95%	24.95%	24.95%
	Kentucky Mid States Div Allocation	100.00%	100.00%	100.00%
	Kentucky Jurisdiction Allocation	100.00%	100.00%	100.00%
	Federal Taxable Income (Loss) from Book/Tax Differences	**(51,090,545)**	**(8,033,323)**	**(21,012,802)**
DIV 02				
	ADIT Beginning of Year	841,973,871	342,022,601	314,468,054
	Less Items Excluded from Rate Base	35,796,993	25,188,290	21,428,201
	Less State Only Items	1,910,422	2,780,160	2,296,070
	Less TCJA Regulatory Liabiltiy related ADIT	-	-	-
	Less Federal NOL	850,194,457	441,283,389	458,676,680
	Adjusted ADIT Beginning of Year	(45,928,001)	(127,229,238)	(167,932,897)
	ADIT End of Year	342,022,601	314,468,054	252,997,116
	Less Items Excluded from Rate Base	25,188,290	21,428,201	19,995,420
	Less State Only Items	2,780,160	2,296,070	2,299,863
	Less TCJA Regulatory Liabiltiy related ADIT	-	-	-
	Less Federal NOL	441,283,389	458,676,680	399,122,247
	Adjusted ADIT End of Year	(127,229,238)	(167,932,897)	(168,420,414)
	Change in Adjusted ADIT	(81,301,236)	(40,703,659)	(487,517)
	Applicable Federal & State Deferred Tax Rate	22.42%	22.42%	22.42%
	Kentucky Mid States Div Allocation	9.86%	9.86%	9.86%
	Kentucky Jurisdiction Allocation	50.42%	50.42%	50.42%
	Federal Taxable Income (Loss) from Book/Tax Differences	**(18,026,132)**	**(9,024,826)**	**(108,093)**
DIV 012				
	ADIT Beginning of Year	(15,341,523)	(14,387,639)	(11,822,885)
	Less Items Excluded from Rate Base	(1,166,404)	(841,660)	(27,859)
	Less State Only Items	-	-	-
	Less TCJA Regulatory Liabiltiy related ADIT	-	-	-
	Adjusted ADIT Beginning of Year	(14,175,119)	(13,545,979)	(11,795,026)
	ADIT End of Year	(14,387,639)	(11,822,885)	(10,661,552)
	Less Items Excluded from Rate Base	(841,660)	(27,859)	(39,651)
	Less State Only Items	-	-	-
	Less TCJA Regulatory Liabiltiy related ADIT	-	-	-
	Adjusted ADIT End of Year	(13,545,979)	(11,795,026)	(10,621,901)
	Change in Adjusted ADIT	629,140	1,750,953	1,173,125
	Applicable Federal & State Deferred Tax Rate	22.42%	22.42%	22.42%
	Kentucky Mid States Div Allocation	11.02%	11.02%	11.02%
	Kentucky Jurisdiction Allocation	50.43%	50.43%	50.43%
	Federal Taxable Income (Loss) from Book/Tax Differences	**155,935**	**433,981**	**290,790**
DIV 091	ADIT Beginning of Year	(3,474,544)	(2,438,663)	(4,559,829)
	Less Items Excluded from Rate Base	1,222,305	1,207,647	1,269,016
	Less State Only Items	-	-	-
	Less TCJA Regulatory Liabiltiy related ADIT	-	-	-
	Adjusted ADIT Beginning of Year	(4,696,849)	(3,646,310)	(5,828,845)
	ADIT End of Year	(2,438,663)	(4,559,829)	(8,390,118)
	Less Items Excluded from Rate Base	1,207,647	1,269,016	1,276,245
	Less State Only Items	-	-	-
	Less TCJA Regulatory Liabiltiy related ADIT	-	-	-
	Adjusted ADIT End of Year	(3,646,310)	(5,828,845)	(9,666,363)
	Change in Adjusted ADIT	1,050,539	(2,182,535)	(3,837,518)
	Applicable Federal & State Deferred Tax Rate	22.42%	22.42%	22.42%
	Kentucky Mid States Div Allocation	100.00%	100.00%	100.00%
	Kentucky Jurisdiction Allocation	50.42%	50.42%	50.42%
	Federal Taxable Income (Loss) from Book/Tax Differences	**2,362,331**	**(4,907,832)**	**(8,629,366)**
	Regulatory Federal Taxable Income (Loss)	**(38,772,027)**	**11,013,723**	**586,113**
	Federal Tax Rate	**21.00%**	**21.00%**	**21.00%**
	Increase / (Decrease) in NOLC ADIT Asset	**8,142,126**	**(2,312,882)**	**(123,084)**

Atmos Enery Corporation
Remaining Book Life for Protected EDIT Amortization

	Kentucky *Protected Amortization Life Summary*	
	Currently Amortization **Including Cost of Removal**	***Proposed Amortization*** **Excluding Cost of Removal**
Plant	651,483,311	651,483,311
Accum Reserve	(177,011,321)	(177,011,321)
Accum Reserve COR	(25,044,068)	-
Total Accum Reserve	(202,055,388)	(177,011,321)
Net Book Value	449,427,923	474,471,991
Depreciation Expense	17,848,661	17,848,661
Cost of Removal Expense	2,619,761	-
Total Depreciation Expense	20,468,423	17,848,661
Composite Depreciation Rate	4.55%	3.76%
Average Remaining Book Life in Years	22	27

Total amortization months currently in rates	264	
Total proposed amortization months to exclude cost of removal	324	
Total months amortized as of April 1 2025 planned rate implementation date	83	
Total Remaining amortization months	241	**(a)**
Total remaining amortization years	20.08	
Remaining protected EDIT liability oas of April 1, 2025	(3,815,790)	**(b)**
Revised monthly EDIT amortization	(15,833)	**(c) = (b) / (a)**
Current monthly EDIT amortization	(21,082)	**(d)**
Change in monthly EDIT amortization	5,249	**(e) = (c) - (d)**
Change in annual EDIT amortization	62,983	**= (e) x 12 months**

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	**)**	**Case No. 2024-00276**

TESTIMONY OF NED W. ALLIS

SUMMARY OF DIRECT TESTIMONY OF NED W. ALLIS

My direct testimony supports and explains the Depreciation Study performed by my firm for Atmos Energy's Kentucky Mid-States General Office. The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of September 30, 2022. Additionally, my testimony provides a depreciation study performed for Atmos Energy's Shared Services Unit performed by Alliance Consulting Group.

INDEX TO THE DIRECT TESTIMONY
OF NED W. ALLIS, WITNESS FOR
ATMOS ENERGY CORPORATION

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EXHIBITS

Exhibit NWA-1 – Depreciation Study of Kentucky Mid-States General Office

Exhibit NWA-2 – Depreciation Study of Shared Services Unit

Exhibit NWA-3 – Comparison of Proposed Annual Depreciation Expense vs. Current Annual Depreciation Expense – Kentucky Mid-States General Office

Exhibit NWA-4 – Comparison of Proposed Annual Depreciation Expense vs. Current Annual Depreciation Expense – Shared Services Unit

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Ned W. Allis. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING?

A. I have been associated with the firm since 2006.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am Vice President.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of Atmos Energy Corporation ("Atmos Energy" or the "Company").

Q. PLEASE STATE YOUR QUALIFICATIONS.

A. I graduated in 2002 with a Bachelor of Science degree in Mathematics from Lafayette College. I joined Gannett Fleming in October 2006 as an analyst. My responsibilities included assembling data required for depreciation studies, conducting statistical analyses of service life and net salvage data, calculating annual and accrued depreciation, and assisting in preparing reports and testimony setting forth and defending the results of the studies. I also developed and maintained Gannett Fleming's proprietary depreciation software. In March 2013,

I was promoted to the position of Supervisor of Depreciation Studies. In March 2017 I was promoted to Project Manager, Depreciation and Technical Development. In January 2019, I was promoted to my current position of Vice President. Since joining Gannett Fleming, I have worked on hundreds of depreciation studies and testified on depreciation-related matters in close to one hundred utility rate cases across the country. Specifically, I have submitted testimony on depreciation related topics to the Connecticut Public Utilities Regulatory Authority, the New York Department of Public Service, the New Jersey Board of Public Utilities, the Nevada Public Utilities Commission, the Florida Public Service Commission, the District of Columbia Public Service Commission, the California Public Utilities Commission, the Rhode Island Public Utilities Commission, the Hawaii Public Utilities Commission, the Massachusetts Department of Public Utilities, the New Hampshire Public Utilities Commission, the Kansas Corporation Commission, the Washington Utilities and Transportation Commission, the Illinois Commerce Commission, the Maine Public Utilities Commission, the Missouri Public Service Commission, and the Maryland Public Service Commission. I have also testified before the Federal Energy Regulatory Commission ("FERC").

I am a member and past President of the Society of Depreciation Professionals ("Society") and an associate member of the American Gas Association/Edison Electric Institute Industry Accounting Committee. I also serve on the faculty for training offered by the Society and am an instructor for the Society's "Introduction to Depreciation," "Life and Net Salvage Analysis,"

"Analyzing the Life of Real-World Property," "Analyzing Net Salvage in the Real World" and "Depreciation and Ratemaking Issues" courses. I passed an examination to become certified by the Society according to established national standards for depreciation professionals in September 2011 and was most recently recertified in January 2022.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports and explains the Depreciation Study performed by my firm for Atmos's Kentucky Mid-States General Office attached as Exhibit NWA-1 ("KMS Depreciation Study"). The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of September 30, 2022.

Additionally, I have attached as Exhibit NWA-2 the Shared Services Unit Depreciation Study conducted by Alliance Consulting Group ("SSU Depreciation Study"). The Shared Services Unit is a division of Atmos Corporation that provides services (such as general office services) to each of the Atmos regulated gas utilities. I have reviewed the SSU Depreciation Study and agree with its analysis.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR DEPRECIATION STUDY.

A. The depreciation rates set forth in the Depreciation Study, as of September 30, 2022, appropriately reflect the rates at which the full cost of the Company's assets should be recovered through depreciation expense. Such rates are based on commonly used methods and procedures for determining depreciation rates. The depreciation rates are based on the average service life procedure, remaining life

technique, and straight line method. The recommended service life estimates are based on informed judgment that incorporates actuarial life analysis based on the retirement rate method and the net salvage estimates are based on widely accepted methods.

Q. ARE THE RECOMMENDED DEPRECIATION ACCRUAL RATES PRESENTED IN THE DEPRECIATION STUDY REASONABLE AND APPLICABLE TO THE PLANT IN SERVICE AS OF SEPTEMBER 30, 2022?

A. Yes, they are. Based on the Depreciation Study, I am recommending depreciation rates using the September 30, 2022 plant and reserve balances for approval.

Q. WHAT IS THE EFFECT OF THE RECOMMENDED DEPRECIATION ACCRUAL RATES ON THE COMPANY'S COST OF SERVICE?

A. The Depreciation Studies result in an increase of approximately $8,400 for the Kentucky Mid-States General Office property as reflected in Exhibit NWA-3. This increase is prior to allocation to each jurisdiction and so the impact for Kentucky customers is approximately $4,200. The results of the SSU study reflect a net decrease allocated to Kentucky customers of approximately $91,800 in depreciation for those assets as reflected in Exhibit NWA-4.

I recommend that the proposed depreciation rates in Exhibits NWA-1 and NWA-2 for the respective depreciable groups (e.g., accounts) be approved.

Q. HAVE OTHER COMPANY SERVICE AREAS APPROVED THE DERPECIATION RATES PROPOSED IN EXHIBITS NWA-1 AND NWA-2?

A. Yes. The two other Kentucky Mid-States Service Areas, Tennessee and Virginia, have approved the proposed Kentucky Mid-States and SSU depreciation rates in Exhibits NWA-1 and NWA-2, respectively. Louisiana and Atmos Pipeline-Texas have approved the proposed SSU depreciation rates in Exhibit NWA-2.

III. DEPRECIATION STUDY

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. The Federal Energy Regulatory Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act defines depreciation as follows.

> Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.[1]

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION?

A. Yes.

Q. WHAT IS THE PURPOSE OF THE DEPRECIATION STUDY?

A. The purpose of my Depreciation Study was to estimate the annual depreciation accruals for Atmos Energy's plant in service for financial and ratemaking purposes,

[1] 18 C.F.R. § 201, Definition 12B.

and to determine appropriate average service lives and net salvage percentages for each plant account.

Q. ARE THE METHODS AND PROCEDURES USED FOR THIS DEPRECIATION STUDY CONSISTENT WITH ATMOS ENERGY'S PAST PRACTICES?

A. The Depreciation Study uses the same method, procedure and technique for calculating depreciation as used in the past by the Company as well as other companies appearing before the Kentucky Public Service Commission. Both the existing rates and the rates determined in the Depreciation Study are based on the straight line method, average service life procedure and the remaining life technique.

Q. PLEASE DESCRIBE THE CONTENTS OF THE DEPRECIATION STUDY.

A. The Depreciation Study is presented in nine parts. Part I, Introduction, presents the scope and basis for the depreciation study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining service life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Part VI also includes Table 1 (see page VI-4 of Exhibit NWA-1), which presents the estimated survivor curve, the net salvage percent, the original cost as of September 30, 2022, the book depreciation reserve, and the calculated annual depreciation accrual and rate for each account or subaccount.

Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account. The section beginning on page VIII-2 presents the results of the net salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of September 30, 2022.

The SSU Depreciation Study incorporates similar descriptions of methodology and analyses as well as tabulations of the results of service life analyses, net salvage analyses and depreciation calculations.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line remaining life method of depreciation with the average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historical data from records related to Atmos Energy's gas plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from Atmos Energy's management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the data and the estimates used by other gas utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1991 through September 2022 to the extent available. The transactions I analyzed included additions, retirements, transfers, sales, and the related balances.

Q. WHAT METHOD DID YOU USE TO ANALYZE THESE SERVICE LIFE DATA?

A. I used the retirement rate method for most plant accounts. The retirement rate method can be used when the vintage year of retirement transactions is known or can be estimated. Data in which the vintage year is available are referred to as "aged data." The retirement rate method is the most appropriate method when retirement aged data are available, because this method determines the rates of retirement experienced by Atmos during the period of time covered by the

Depreciation Study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE ATMOS ENERGY'S SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the Depreciation Study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The "Iowa-type survivor curves" were used to perform these interpretations.

Q. WHAT ARE "IOWA-TYPE SURVIVOR CURVES" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa-type survivor curves ("Iowa curves") are the industry standard system of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. These curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa

curves were used in the Depreciation Studies to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 50-R3 indicates an average service life of fifty years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 3, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. DID YOU PHYSICALLY OBSERVE ATMOS ENERGY'S PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDY?

A. At the time the Depreciation Study was conducted, I made a separate, concurrent study of the Company's assets in the neighboring state of Virginia. The field review I conducted was of Atmos Energy's property in Viriginia which is also served by the Kentucky Mid-States General Office. The visit made to the Virigina assets helped in becoming familiar with company operations and obtaining an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with Atmos Energy's management and operating personnel, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. HOW DID YOUR EXPERIENCE IN DEVELOPMENT OF OTHER DEPRECIATION STUDIES AFFECT YOUR WORK IN THIS CASE FOR ATMOS ENERGY?

A. Because my firm, Gannett Fleming, customarily conducts field reviews for depreciation studies, I have had the opportunity to visit many similar facilities and meet with management and operations personnel at many other companies. The knowledge I have accumulated from those visits and meetings provides me with useful information to draw upon to incorporate into the informed judgment used to estimate service lives and net salvage.

Q. PLEASE EXPLAIN THE CONCEPT OF "NET SALVAGE."

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire the asset exceeds the salvage value, the result is negative net salvage.

Because depreciation expense is the loss in service value of an asset during a defined period (*e.g.,* one year), it must include a ratable portion of both the original cost of the asset and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost, so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value. For example, the full service value of a $1,000 regulator also includes $250 of cost of removal and $50 gross salvage, for a total service value of

$1,200.

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. I estimated the net salvage percentages by incorporating Atmos Energy's actual historical data for the period 2008 through September 2022 and considered industry experience of net salvage estimates for other gas companies. The net salvage percentages in the Depreciation Study are based on a combination of statistical analyses and informed judgment. The statistical analyses consider the cost of removal and gross salvage ratios to the associated retirements during the 15-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates as of September 30, 2022 for each group using the straight line remaining life method, and using remaining lives weighted consistent with the average service life procedure.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method (also referred to as the straight line method, remaining life technique) of depreciation allocates the original cost of the property,

less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE DESCRIBE THE AVERAGE SERVICE LIFE PROCEDURE FOR CALCULATING REMAINING LIFE ACCRUAL RATES.

A. The average service life procedure defines the group or account for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and the rate is then applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. The sum of the future book accruals is then divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Ned W. Allis, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.

Ned W. Allis

COMMONWEALTH OF PENNSYLVANIA

COUNTY OF CUMBERLAND

SUBSCRIBED AND SWORN to before me by Ned W. Allis on this the 26th day of September, 2024.

Commonwealth of Pennsylvania - Notary Seal
Cheryl Ann Rutter, Notary Public
Cumberland County
My commission expires February 20, 2027
Commission number 1143028
Member, Pennsylvania Association of Notaries

Notary Public

My Commission Expires: February 20, 2027

ATMOS ENERGY CORPORATION

KENTUCKY MID-STATES GENERAL OFFICE

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AS OF SEPTEMBER 30, 2022

Prepared by:



GANNETT FLEMING

Excellence Delivered As Promised

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
Dallas, Texas

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2022

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
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May 10, 2023

Atmos Energy Corporation
5430 Lyndon B. Johnson Freeway
Dallas, TX 75240

Attention: Joe Christian

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the gas plant of Atmos Energy Corporation – Kentucky Mid-States General Office as of September 30, 2022. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual depreciation.

We gratefully acknowledge the assistance of Atmos Energy Corporation personnel in the conduct of this study.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

NED W. ALLIS
Vice President

NWA:jmr
073610.000

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ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Atmos Energy Corporation's ("Atmos") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the gas plant of the Kentucky Mid-States General Office as of September 30, 2022. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated survivor curves and forecasted net salvage characteristics for each depreciable group of assets.

The service life and net salvage estimates recommended in the depreciation study are based on informed judgment that incorporates the statistical analyses of historical data through 2022. In general, the service lives have trended shorter for many accounts and the recommended service lives have decreased since the previous depreciation study. In general, the depreciation rates proposed in this study result in a slightly higher level of depreciation expense than the rates recommended in the previous depreciation study. This was primarily the result of changes in the estimated service life and net salvage parameters for some accounts.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service as of September 30, 2022 as

summarized in Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $57 thousand when applied to depreciable plant balances as of September 30, 2022. The results are summarized at the functional level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF SEPTEMBER 30, 2022	PROPOSED RATE	PROPOSED EXPENSE
GENERAL PLANT	752,201.92	7.55	56,772
TOTAL DEPRECIABLE PLANT	**$752,201.92**	7.55	**$56,772**

PART I. INTRODUCTION

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Atmos Energy Corporation's ("Atmos") Kentucky Mid-States General Office, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of gas plant as of September 30, 2022. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to gas plant in service as of September 30, 2022.

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2022, a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the gas industry, including knowledge of service lives and net salvage estimates used for other gas companies.

PLAN OF REPORT

Part I, Introduction, describes the plan of the report and the basis of the study. Part II, Estimation of Survivor Curves, provides descriptions of the considerations and the methods used in the service life and net salvage analyses. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, discusses the judgment utilized in the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study,

presents summaries by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics, provides the statistical analysis of service life estimates; Part VIII, Net Salvage Statistics, sets forth the statistical indications of net salvage percents; and Part IX, Detailed Depreciation Calculations, presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance and which is incurred in through the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is distribution of an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. Calculations were based on original cost, attained ages, and estimates of service lives and net salvage.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been accepted in jurisdictions throughout North America. Average service life is the same procedure recommended in the Company's previous depreciation study and Gannett Fleming recommends its continued use in this study.

Service Life and Net Salvage Estimates

The service life and net salvage estimates used in the depreciation calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the gas utility industry, and comparisons of the service life and net salvage estimates from our studies of other gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to model the estimated survivor curves for the plant accounts.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group based on interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

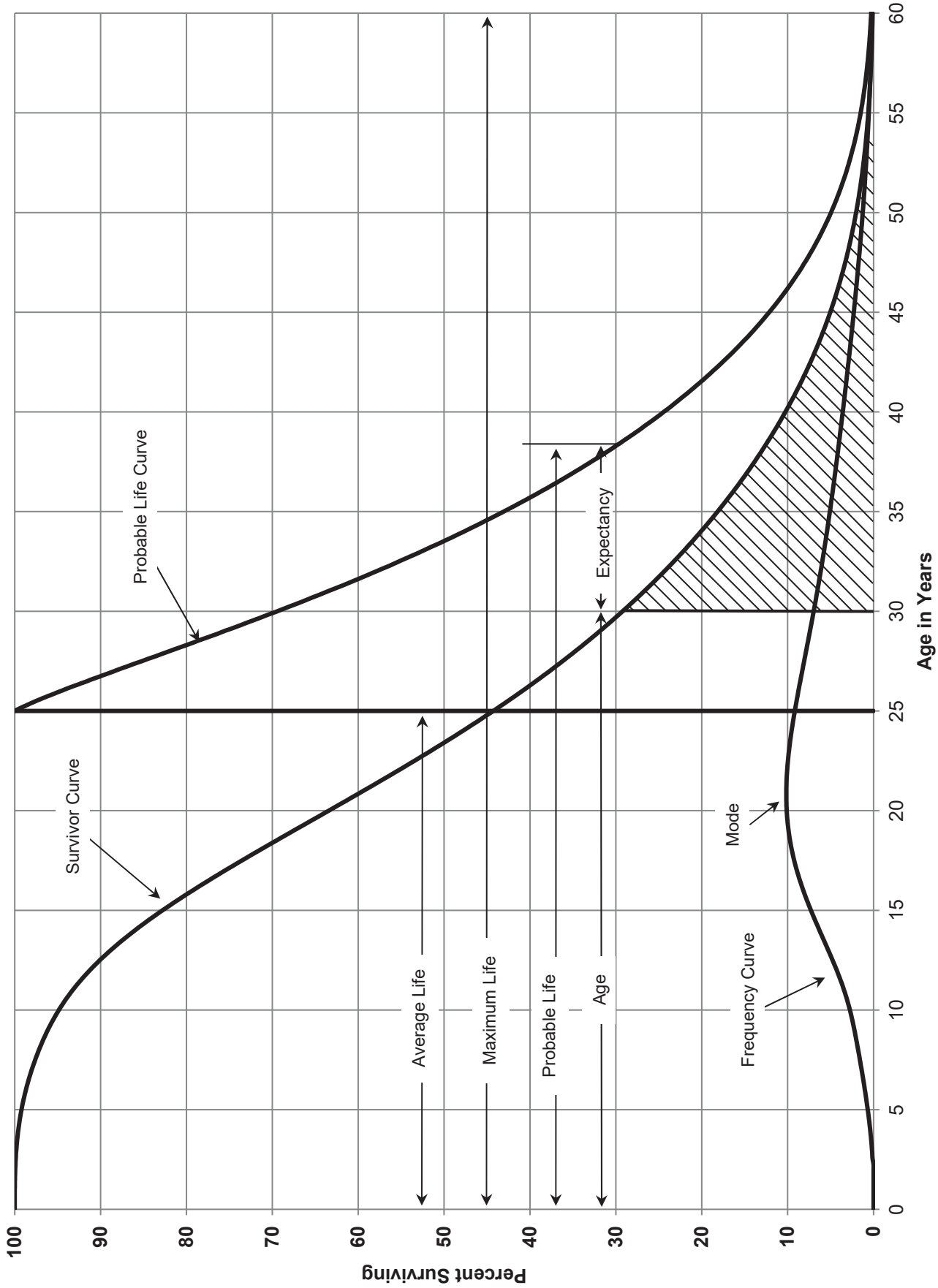


FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

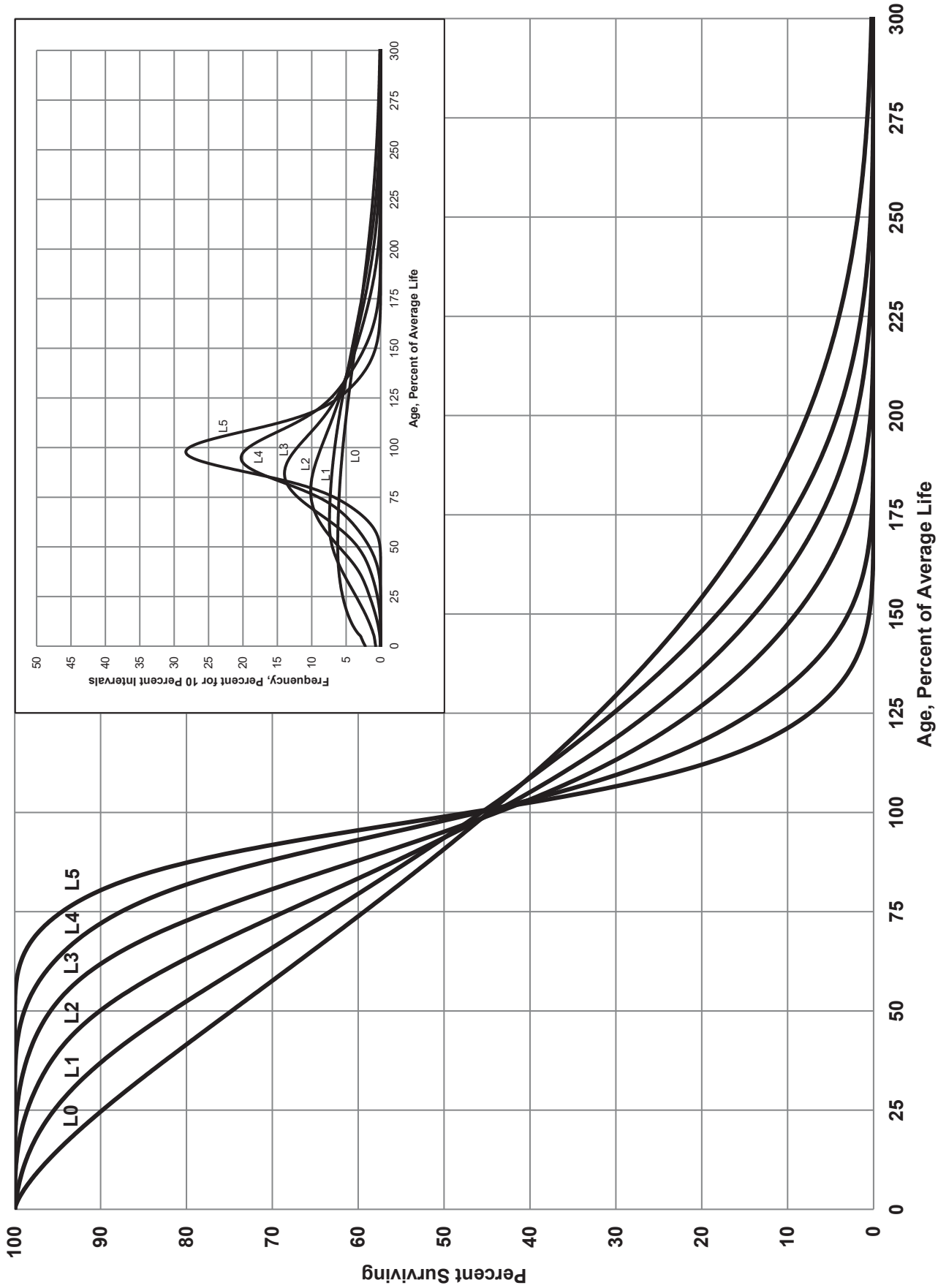


FIGURE 2.. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

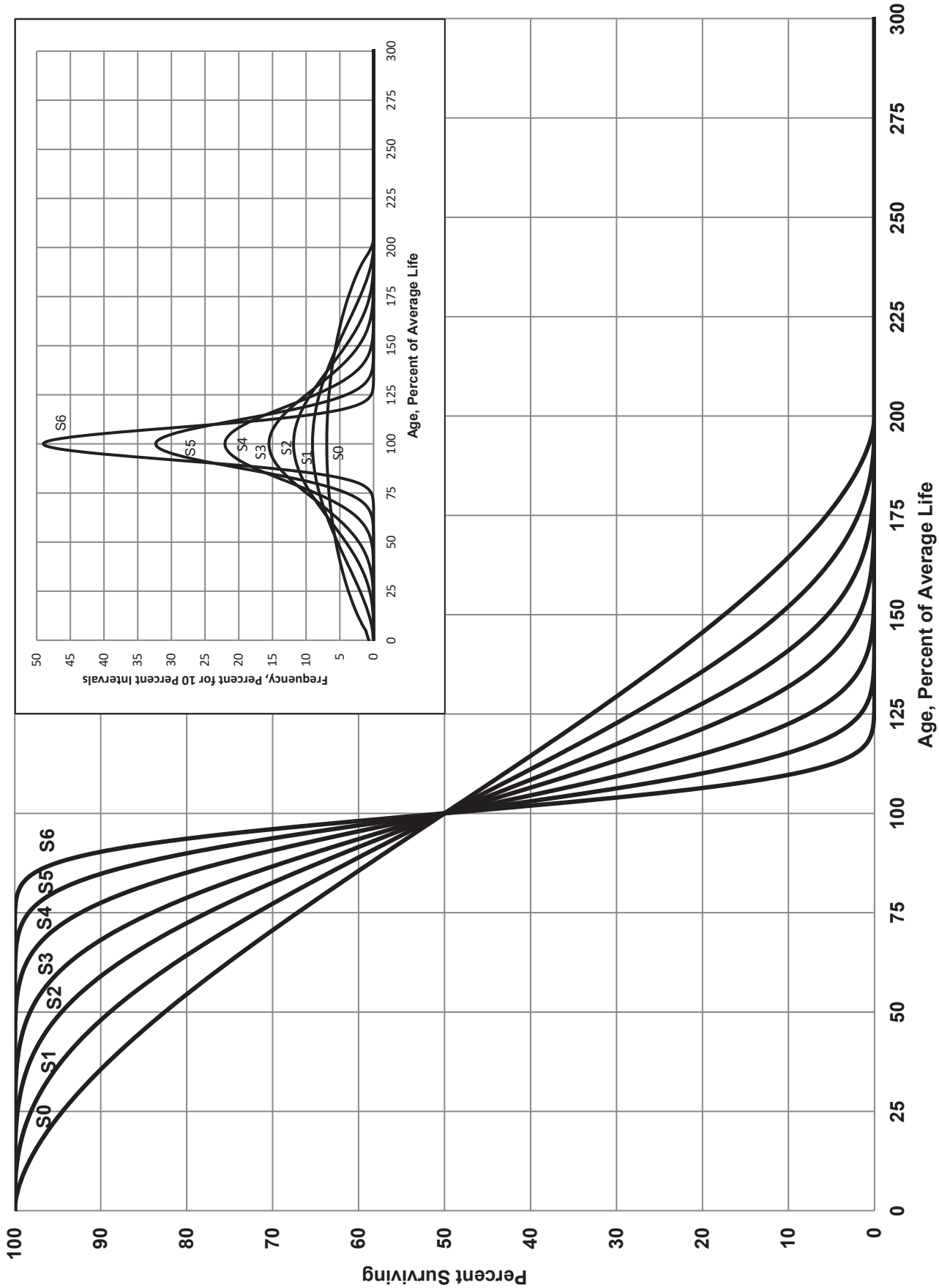


FIGURE 3.. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

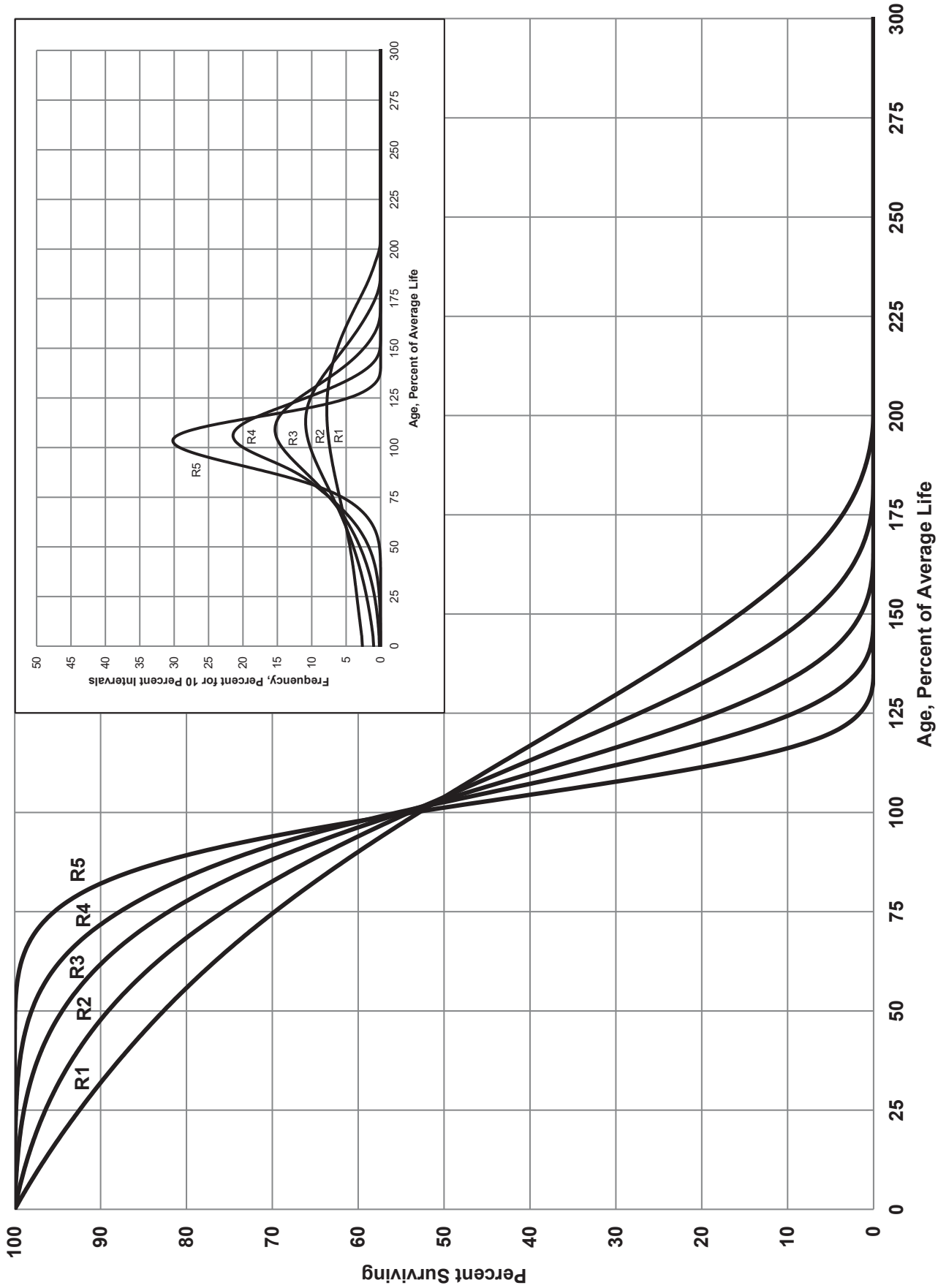


FIGURE 4.. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

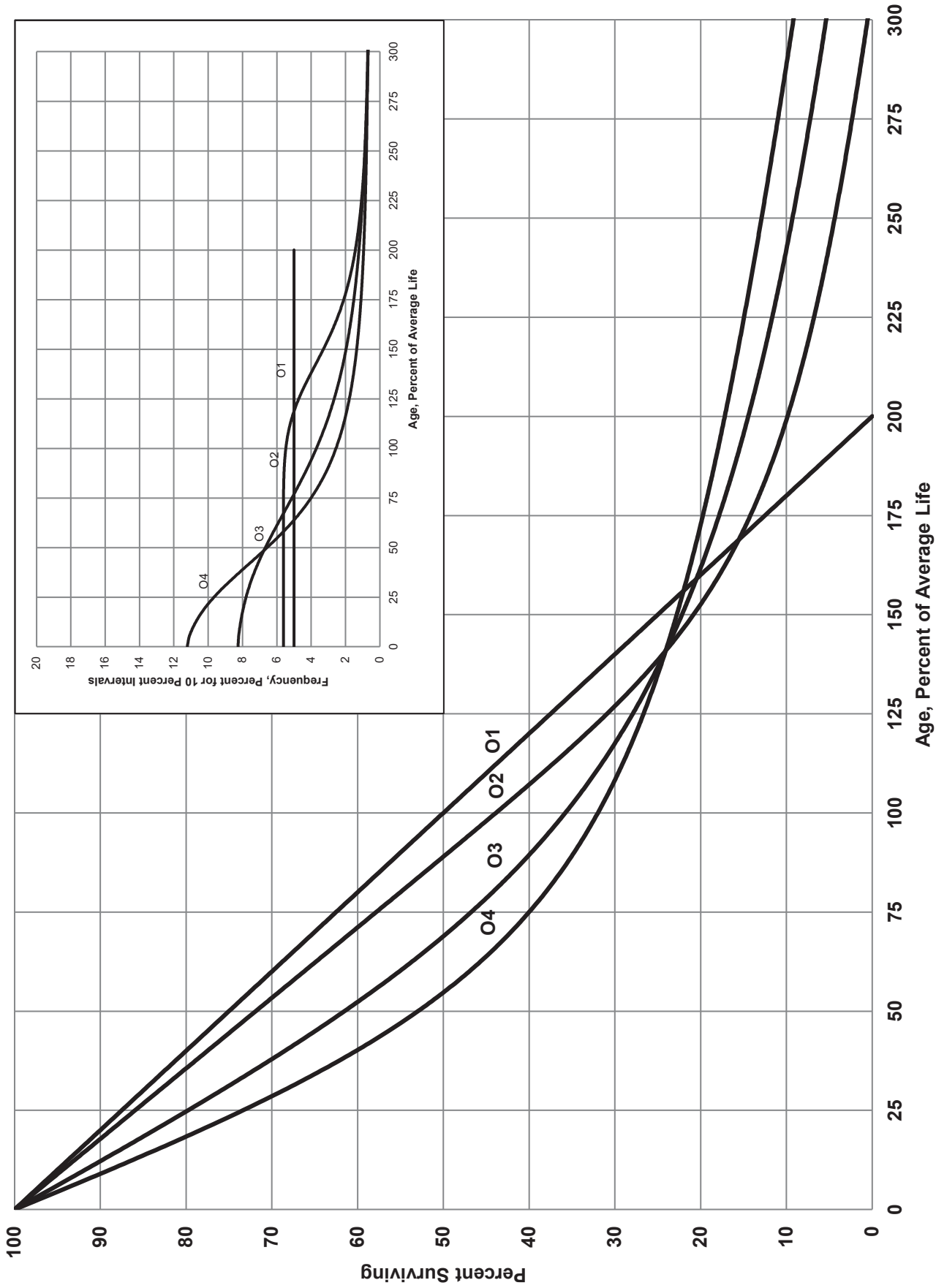


FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2013-2022 for which there were placements during the years 2008-2022. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2008 were retired in 2013. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2013 retirements of 2008 installations and ending with the 2022 retirements of the 2017 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 Placement Band 2008-2022

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2009	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2010	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2011	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2012	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2013	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2014		5	11	12	13	14	15	16	18	20	113	7½-8½
2015			6	12	13	15	16	17	19	19	124	6½-7½
2016				6	13	15	16	17	19	19	131	5½-6½
2017					7	14	16	17	19	20	143	4½-5½
2018						8	18	20	22	23	146	3½-4½
2019							9	20	22	25	150	2½-3½
2020								11	23	25	151	1½-2½
2021									11	24	153	½-1½
2022										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 Placement Band 2008-2022

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2009	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2010	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2011	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2012	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2013	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2014		-	-	-	-	-	-	-	-	-	6	7½-8½
2015			-	-	-	-	-	-	-	-	-	6½-7½
2016				-	-	-	-	(12)[b]	-	-	-	5½-6½
2017					-	-	-	-	22[a]	-	-	4½-5½
2018						-	-	(19)[b]	-	-	10	3½-4½
2019							-	-	-	-	-	2½-3½
2020								-	-	(102)[c]	(121)	1½-2½
2021									-	-	-	½-1½
2022											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year

[b] Transfer Affecting Exposures at End of Year

[c] Sale with Continued Use

Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2013 through 2022 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2018 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 Placement Band 2008-2022

Year Placed	Exposures, Thousands of Dollars Annual Survivors at the Beginning of the Year 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total at Beginning of Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2009	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2010	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2011	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2012	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2013	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2014		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2015			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2016				580[a]	574	561	546	530	501	482	3,057	5½-6½
2017					660[a]	653	639	623	628	609	3,789	4½-5½
2018						750[a]	742	724	685	663	4,332	3½-4½
2019							850[a]	841	821	799	4,955	2½-3½
2020								960[a]	949	926	5,719	1½-2½
2021									1,080[a]	1,069	6,579	½-1½
2022										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2013-2022, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2013-2022 Placement Band 2008-2022

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

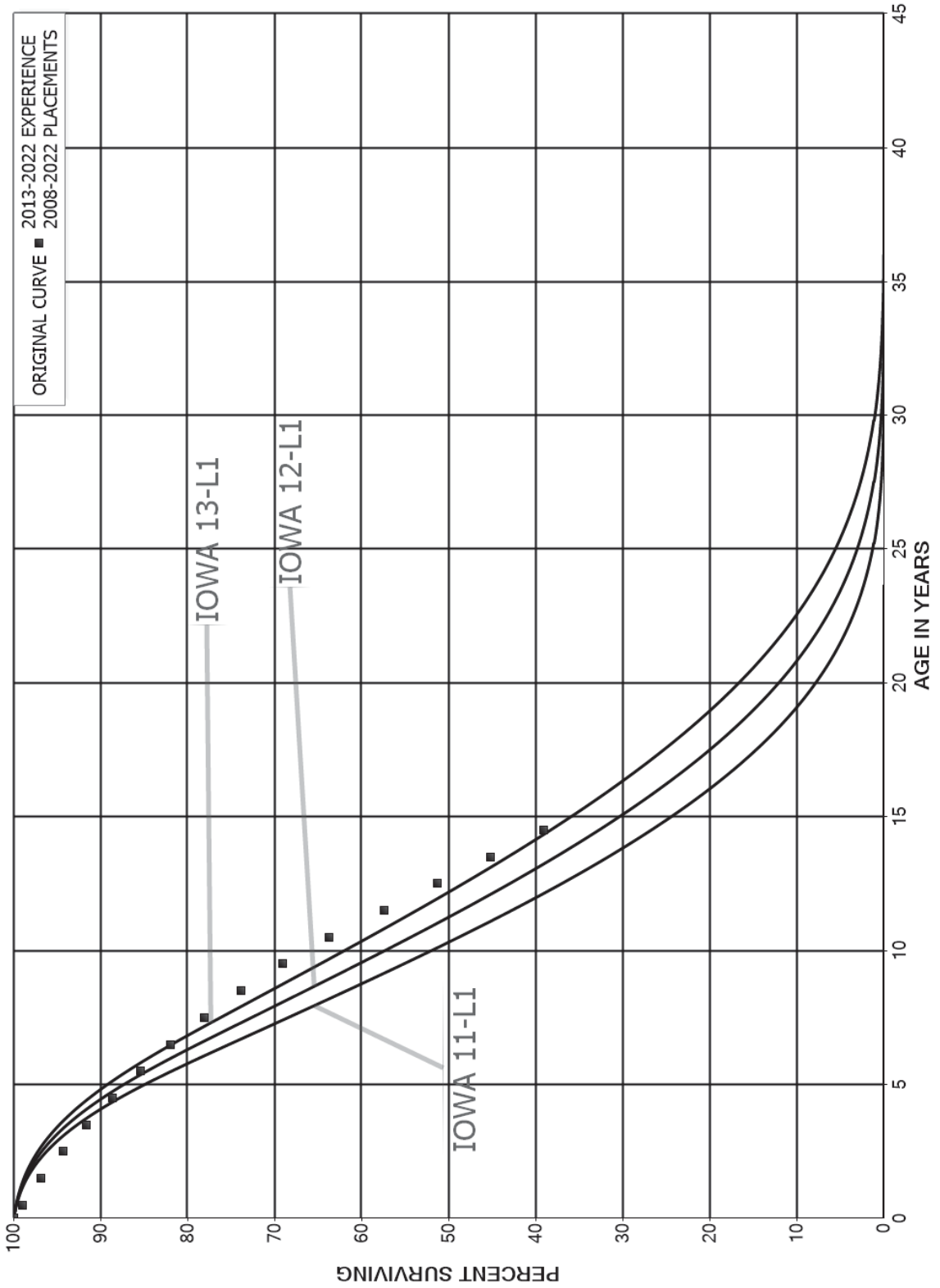


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

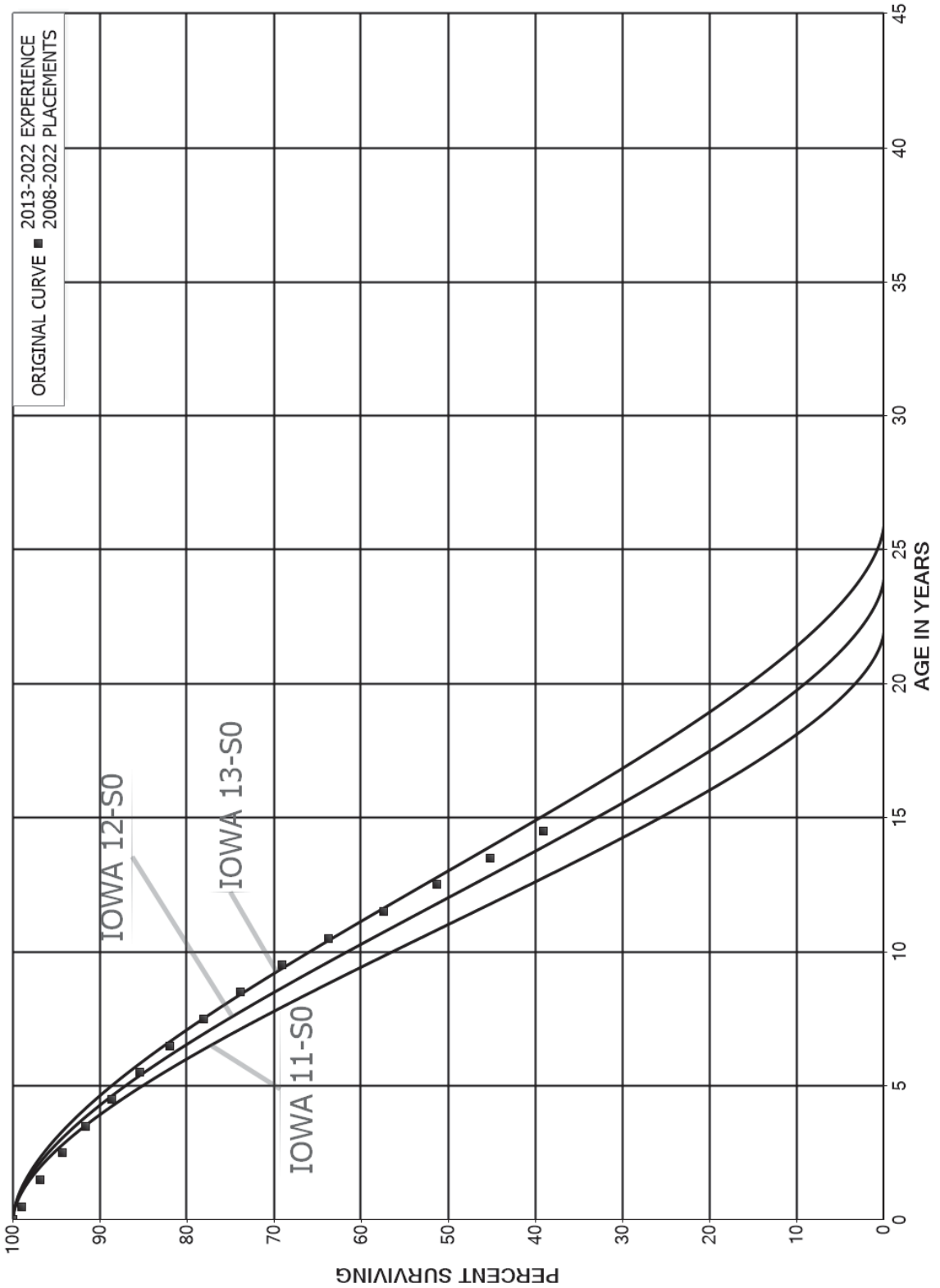


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

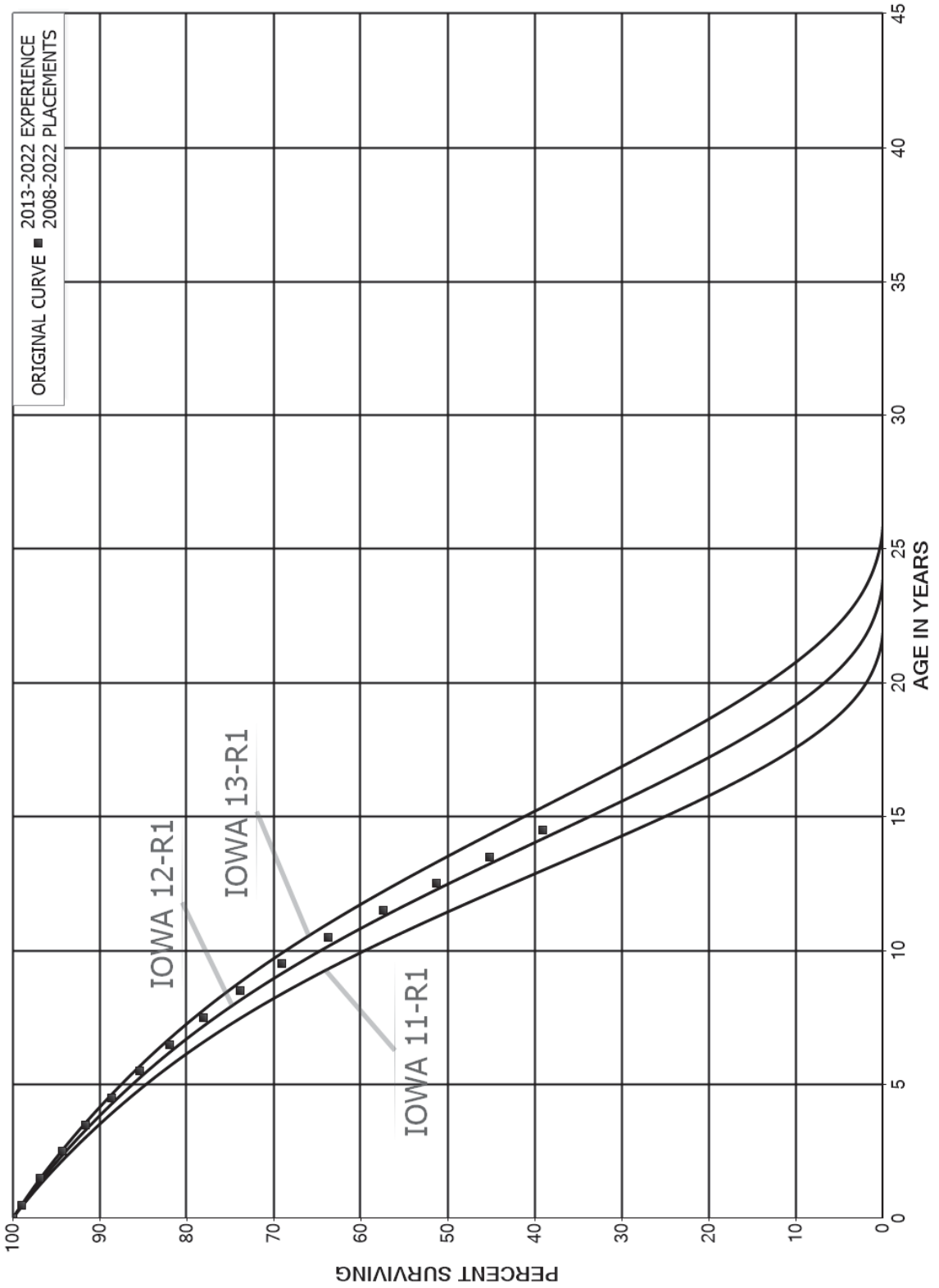
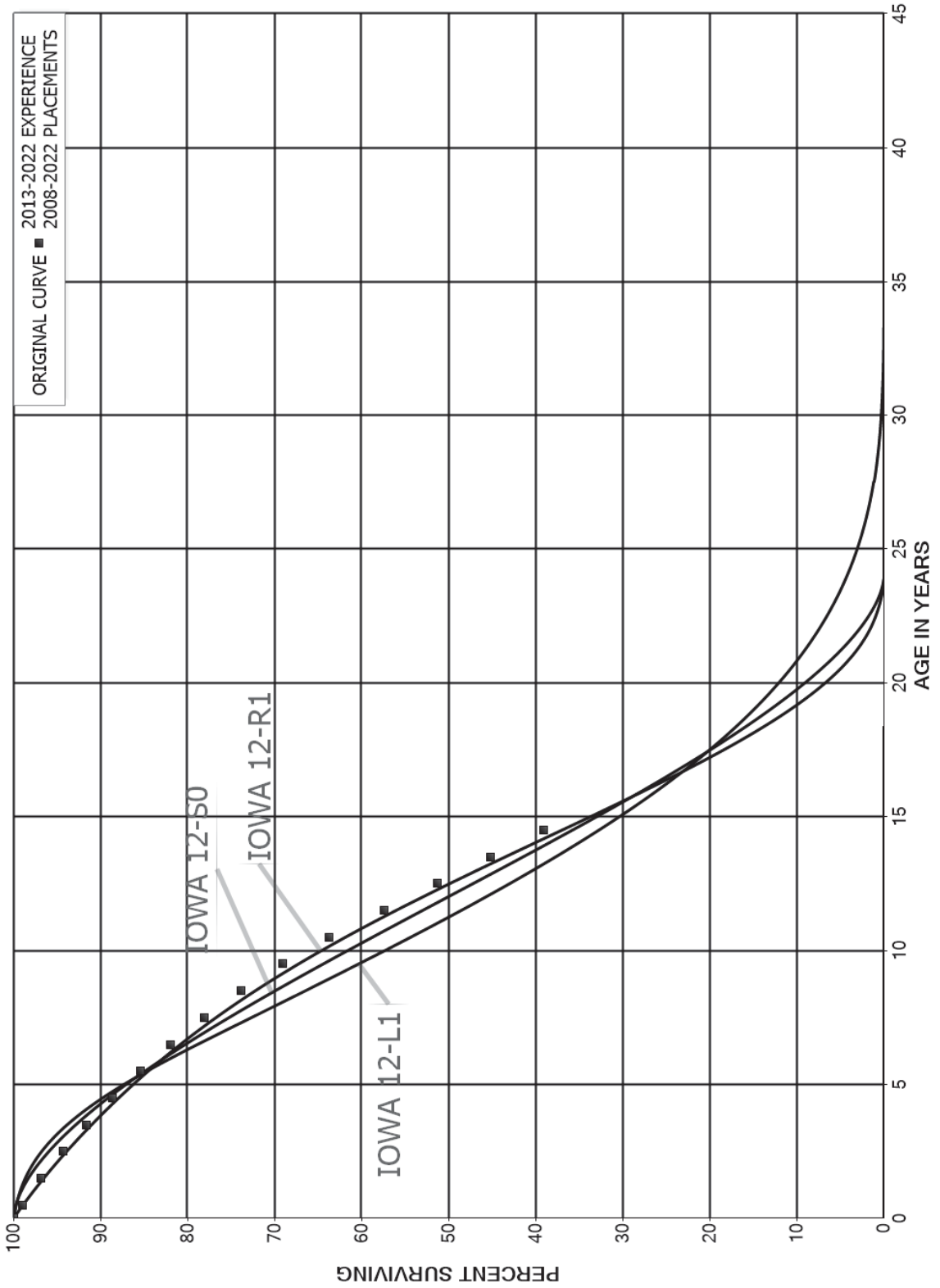


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

To become familiar with the operation of the Company and observe representative portions of the plant, a field trip is typically conducted for the study. At the time of this study, a separate study was concurrently being performed for Company's assets in the neighboring state of Virginia which is also served by the Kentucky Mid-States General Office. The visit made to assets in Virginia helped in the general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

SERVICE LIFE ANALYSIS

The service life estimates were based on informed judgment which considered various factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other gas companies.

For many of the plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method contributed significantly towards the recommended survivor curves. These accounts represent 55 percent of depreciable plant. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

GAS PLANT

General Plant

391.00	Office Furniture and Equipment
394.00	Tools, Shop and Garage Equipment
396.00	Power Operated Equipment
399.03	Other Tangible Property – Network Hardware
399.08	Other Tangible Property – Application Equipment

Account 394.00, Tools, Shop and Garage Equipment, is the largest plant account and is used to illustrate the manner in which the study was conducted for the accounts in the preceding list. Aged plant accounting data is available from 1992 through 2022. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place and year in which the utility plant was placed in service. The retirements, other plant transactions and plant additions were analyzed by the retirement rate method. The current survivor curve estimate for this account is the 15-R5. The statistical analysis through 2022 indicates a service life similar to the current estimate is appropriate. The proposed 15-R4 survivor curve is based on the statistical indication for the periods 1997 through 2022 and 2001 through 2022. The 15-R4 is a reasonable fit of a portion of the original survivor curve as set forth on page VII-13, is consistent with the considerations discussed above and with management outlook for the account, and it is within the typical industry range of average service lives of 15 to 25 years for tools, shop and garage equipment.

Generally, the survivor curve estimates for the remaining accounts were based on judgments which considered the statistical analyses, the nature of the plant and equipment, the previous estimate for the Company and a general knowledge of service lives for similar equipment in other gas companies.

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

NET SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled for the years 2008 through 2022. Cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, that is, all future retirements. In cases in which removal costs are expected to exceed gross salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and gross salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and gross salvage data are presented in the section titled “Net Salvage Statistics” for the plant accounts in which the net salvage estimate relied partially on those analyses. Due to the data available and the types of assets included in the study, the net salvage percents for most accounts were based on judgment incorporating estimates of previous studies of this and other gas utilities.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1{,}000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1{,}000 \left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of September 30, 2022, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of September 30, 2022, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and net salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the gas plant in service as of September 30, 2022. For most plant accounts, the application of such rates to future balances, that reflect additions subsequent to September 30, 2022, is reasonable for a period of three to five years.

DESCRIPTION OF DETAILED TABULATIONS

Table 1 is a summary of the results of the study as applied to the original cost of gas plant as of September 30, 2022 presented on page VI-4 of this report.

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other gas utilities. The results of the statistical analysis of service life are presented in the section beginning on page VII-2, within the supporting documents of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of

the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The analyses of net salvage data are presented in the section titled, “Net Salvage Statistics.” The tabulations present annual cost of removal and gross salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

The tables of the calculated annual depreciation applicable to depreciable assets as of September 30, 2022 are presented in account sequence starting on page IX-2 of the supporting documents. The tables indicate the estimated survivor curve and net salvage percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life, and the calculated annual accrual amount.

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

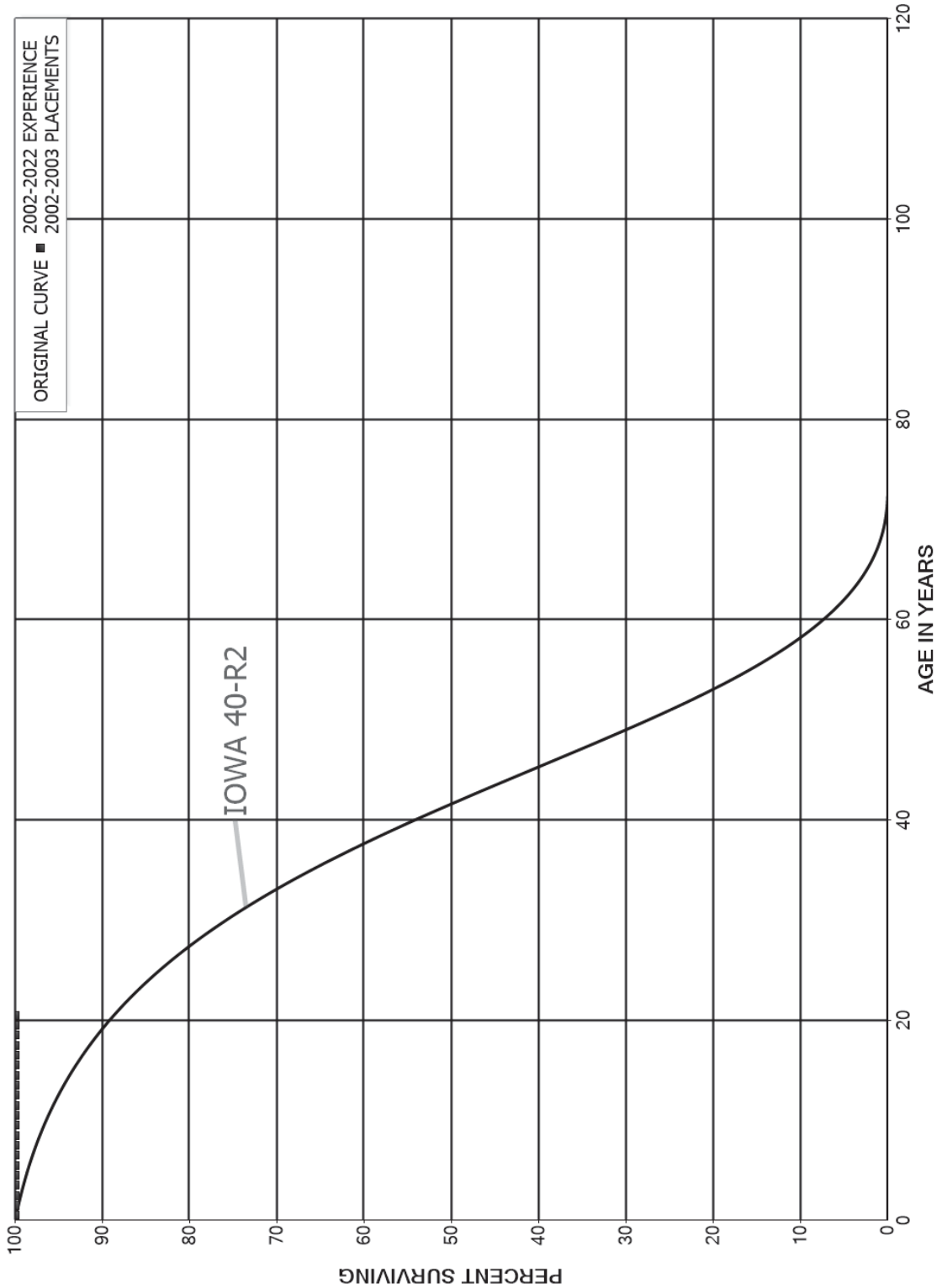
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2022

ACCOUNT		SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE		COMPOSITE REMAINING LIFE
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)		(9)=(6)/(7)
GENERAL PLANT										
390.01	STRUCTURES AND IMPROVEMENTS - FRAME	40 - R2	(10)	179,338.52	13,097	184,175	7,890	4.40		23.3
390.04	STRUCTURES AND IMPROVEMENTS - AIR CONDITIONING EQUIPMENT	15 - R2	(10)	15,383.91	10,853	6,069	625	4.06		9.7
390.09	STRUCTURES AND IMPROVEMENTS - IMPROVEMENTS - LEASED	20 - R3	0	38,834.00	38,834	0	0	-	*	-
391.00	OFFICE FURNITURE AND EQUIPMENT	20 - R3	0	26,927.93	4,070	22,858	1,731	6.43		13.2
392.00	TRANSPORTATION EQUIPMENT	12 - L2.5	5	27,284.69	14,272	11,648	2,479	9.09		4.7
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	15 - R4	0	110,227.42	34,405	75,822	6,717	6.09		11.3
396.00	POWER OPERATED EQUIPMENT	15 - L3	5	9,478.52	1,015	7,990	986	10.40		8.1
399.03	OTHER TANGIBLE PROPERTY - NETWORK HARDWARE	10 - R4	0	28,266.44	6,749	21,517	3,106	10.99		6.9
399.07	OTHER TANGIBLE PROPERTY - PC SOFTWARE	7 - R4	0	78,585.68	55,776	22,810	10,366	13.19		2.2
399.08	OTHER TANGIBLE PROPERTY - APPLICATION SOFTWARE	10 - R4	0	237,874.81	192,814	45,061	22,872	9.62		2.00
TOTAL GENERAL PLANT				**752,201.92**	**371,885**	**397,950**	**56,772**	**7.55**		
TOTAL DEPRECIABLE PLANT				**752,201.92**	**371,885**	**397,950**	**56,772**	**7.55**		
NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED										
301.00	ORGANIZATION			185,309.27						
303.00	MISCELLANEOUS INTANGIBLE PLANT			1,109,551.68						
TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED				**1,294,860.95**						
TOTAL GAS PLANT				**2,047,062.87**	**371,885**					

* NEW ADDITIONS TO THIS ACCOUNT WILL UTILIZE A DEPRECIATION RATE OF 5.00%

PART VII. SERVICE LIFE STATISTICS

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 390.01 STRUCTURES AND IMPROVEMENTS - FRAME
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

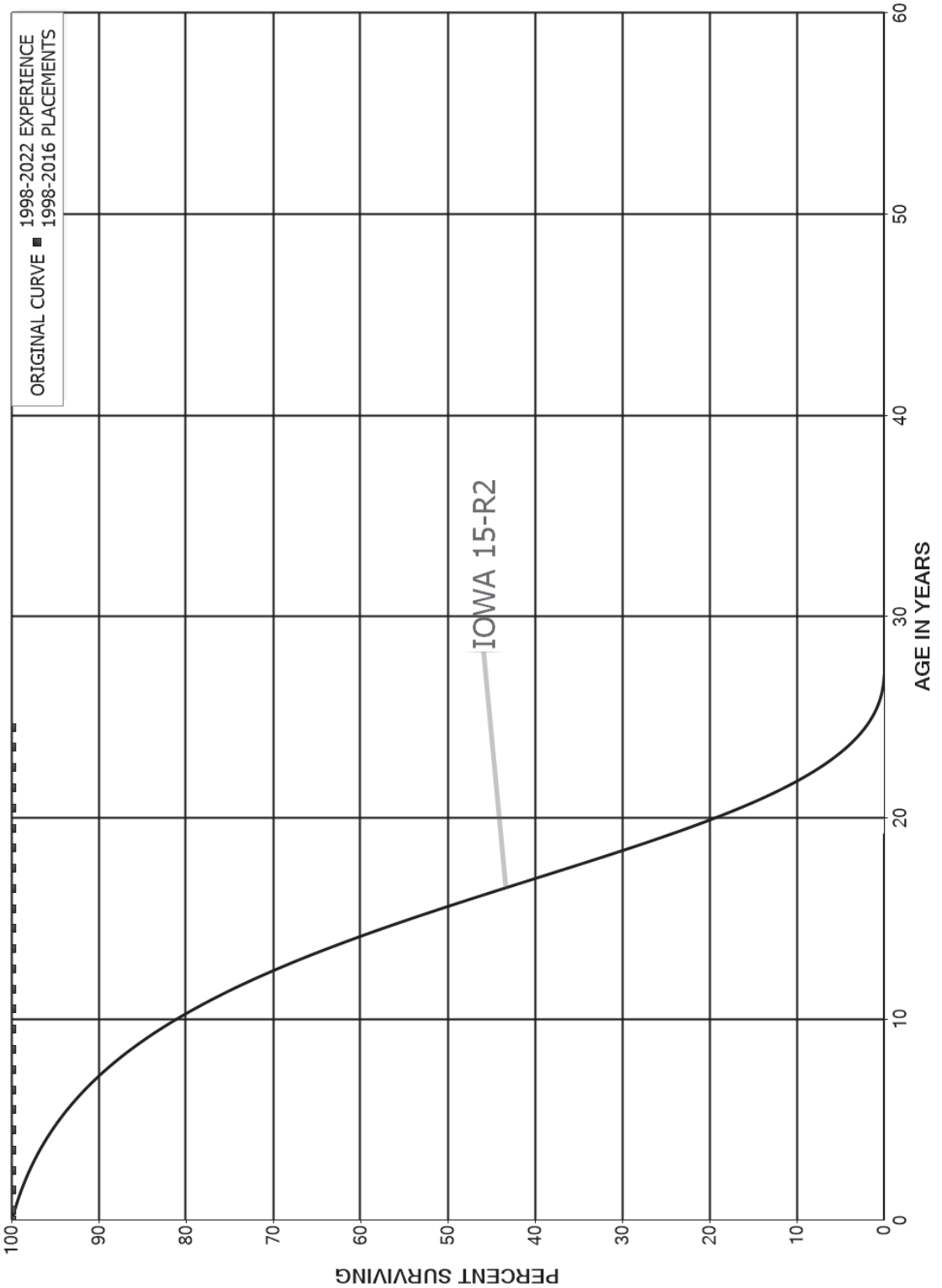
ACCOUNT 390.01 STRUCTURES AND IMPROVEMENTS - FRAME

ORIGINAL LIFE TABLE

PLACEMENT BAND 2002-2003 EXPERIENCE BAND 2002-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	179,339		0.0000	1.0000	100.00
0.5	179,339		0.0000	1.0000	100.00
1.5	179,339		0.0000	1.0000	100.00
2.5	179,339		0.0000	1.0000	100.00
3.5	179,339		0.0000	1.0000	100.00
4.5	179,339		0.0000	1.0000	100.00
5.5	179,339		0.0000	1.0000	100.00
6.5	179,339		0.0000	1.0000	100.00
7.5	179,339		0.0000	1.0000	100.00
8.5	179,339		0.0000	1.0000	100.00
9.5	179,339		0.0000	1.0000	100.00
10.5	179,339		0.0000	1.0000	100.00
11.5	179,339		0.0000	1.0000	100.00
12.5	179,339		0.0000	1.0000	100.00
13.5	179,339		0.0000	1.0000	100.00
14.5	179,339		0.0000	1.0000	100.00
15.5	179,339		0.0000	1.0000	100.00
16.5	179,339		0.0000	1.0000	100.00
17.5	179,339		0.0000	1.0000	100.00
18.5	179,339		0.0000	1.0000	100.00
19.5	143,669		0.0000	1.0000	100.00
20.5					100.00

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 390.04 STRUCTURES AND IMPROVEMENTS - AIR CONDITIONING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

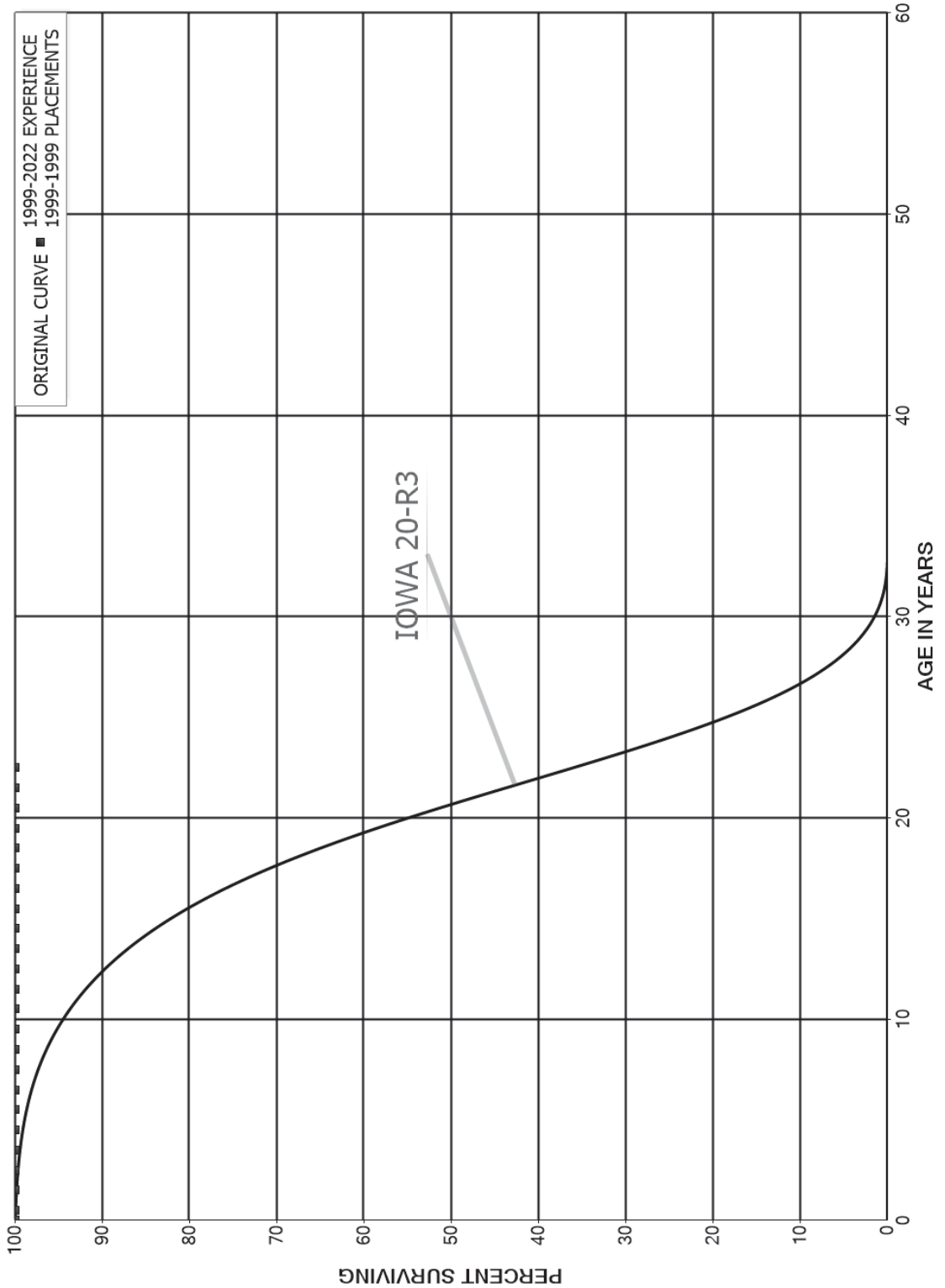
ACCOUNT 390.04 STRUCTURES AND IMPROVEMENTS - AIR CONDITIONING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1998-2016 EXPERIENCE BAND 1998-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	15,384		0.0000	1.0000	100.00
0.5	15,384		0.0000	1.0000	100.00
1.5	15,384		0.0000	1.0000	100.00
2.5	15,384		0.0000	1.0000	100.00
3.5	15,384		0.0000	1.0000	100.00
4.5	15,384		0.0000	1.0000	100.00
5.5	15,384		0.0000	1.0000	100.00
6.5	5,771		0.0000	1.0000	100.00
7.5	5,771		0.0000	1.0000	100.00
8.5	5,771		0.0000	1.0000	100.00
9.5	5,771		0.0000	1.0000	100.00
10.5	5,771		0.0000	1.0000	100.00
11.5	5,771		0.0000	1.0000	100.00
12.5	5,771		0.0000	1.0000	100.00
13.5	5,771		0.0000	1.0000	100.00
14.5	5,771		0.0000	1.0000	100.00
15.5	5,771		0.0000	1.0000	100.00
16.5	5,771		0.0000	1.0000	100.00
17.5	5,771		0.0000	1.0000	100.00
18.5	5,771		0.0000	1.0000	100.00
19.5	5,771		0.0000	1.0000	100.00
20.5	5,771		0.0000	1.0000	100.00
21.5	5,771		0.0000	1.0000	100.00
22.5	5,771		0.0000	1.0000	100.00
23.5	5,771		0.0000	1.0000	100.00
24.5					100.00

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 390.09 STRUCTURES AND IMPROVEMENTS - IMPROVEMENTS - LEASED
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

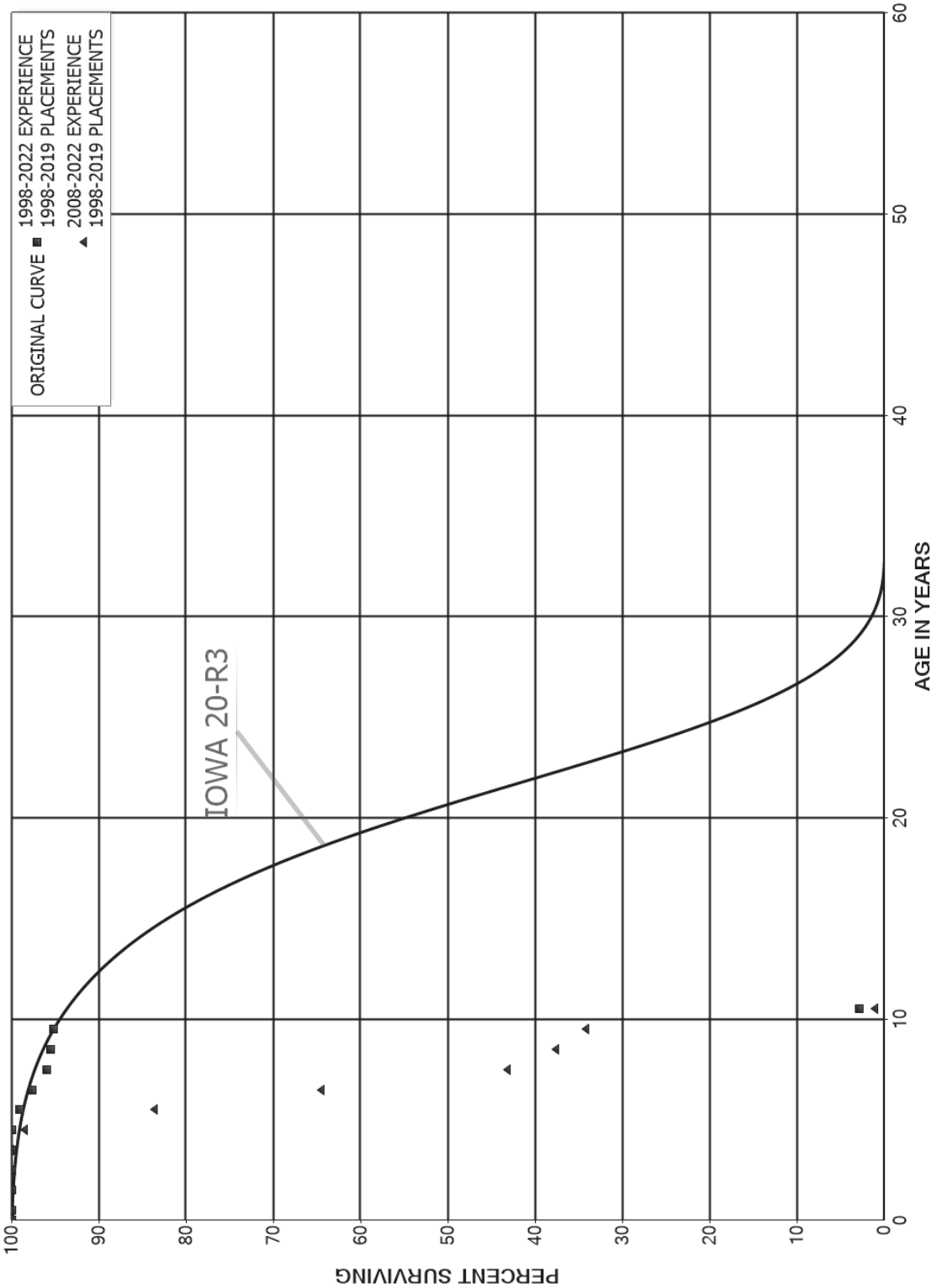
ACCOUNT 390.09 STRUCTURES AND IMPROVEMENTS - IMPROVEMENTS - LEASED

ORIGINAL LIFE TABLE

PLACEMENT BAND 1999-1999 EXPERIENCE BAND 1999-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	38,834		0.0000	1.0000	100.00
0.5	38,834		0.0000	1.0000	100.00
1.5	38,834		0.0000	1.0000	100.00
2.5	38,834		0.0000	1.0000	100.00
3.5	38,834		0.0000	1.0000	100.00
4.5	38,834		0.0000	1.0000	100.00
5.5	38,834		0.0000	1.0000	100.00
6.5	38,834		0.0000	1.0000	100.00
7.5	38,834		0.0000	1.0000	100.00
8.5	38,834		0.0000	1.0000	100.00
9.5	38,834		0.0000	1.0000	100.00
10.5	38,834		0.0000	1.0000	100.00
11.5	38,834		0.0000	1.0000	100.00
12.5	38,834		0.0000	1.0000	100.00
13.5	38,834		0.0000	1.0000	100.00
14.5	38,834		0.0000	1.0000	100.00
15.5	38,834		0.0000	1.0000	100.00
16.5	38,834		0.0000	1.0000	100.00
17.5	38,834		0.0000	1.0000	100.00
18.5	38,834		0.0000	1.0000	100.00
19.5	38,834		0.0000	1.0000	100.00
20.5	38,834		0.0000	1.0000	100.00
21.5	38,834		0.0000	1.0000	100.00
22.5	38,834		0.0000	1.0000	100.00
23.5					100.00

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 391.00 OFFICE FURNITURE AND EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 391.00 OFFICE FURNITURE AND EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1998-2019 EXPERIENCE BAND 1998-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,377,061		0.0000	1.0000	100.00
0.5	1,377,061		0.0000	1.0000	100.00
1.5	1,372,730		0.0000	1.0000	100.00
2.5	1,372,730		0.0000	1.0000	100.00
3.5	1,370,273	1,312	0.0010	0.9990	100.00
4.5	1,353,818	11,545	0.0085	0.9915	99.90
5.5	1,342,273	19,785	0.0147	0.9853	99.05
6.5	1,322,487	22,133	0.0167	0.9833	97.59
7.5	1,297,405	5,972	0.0046	0.9954	95.96
8.5	1,291,433	3,957	0.0031	0.9969	95.52
9.5	1,287,476	1,249,496	0.9705	0.0295	95.22
10.5	45,213	2,321	0.0513	0.9487	2.81
11.5	42,892	5,003	0.1166	0.8834	2.66
12.5	37,890		0.0000	1.0000	2.35
13.5	31,512	26,022	0.8258	0.1742	2.35
14.5	5,490	3,260	0.5938	0.4062	0.41
15.5	2,230		0.0000	1.0000	0.17
16.5	2,230	2,230	1.0000		0.17
17.5					

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

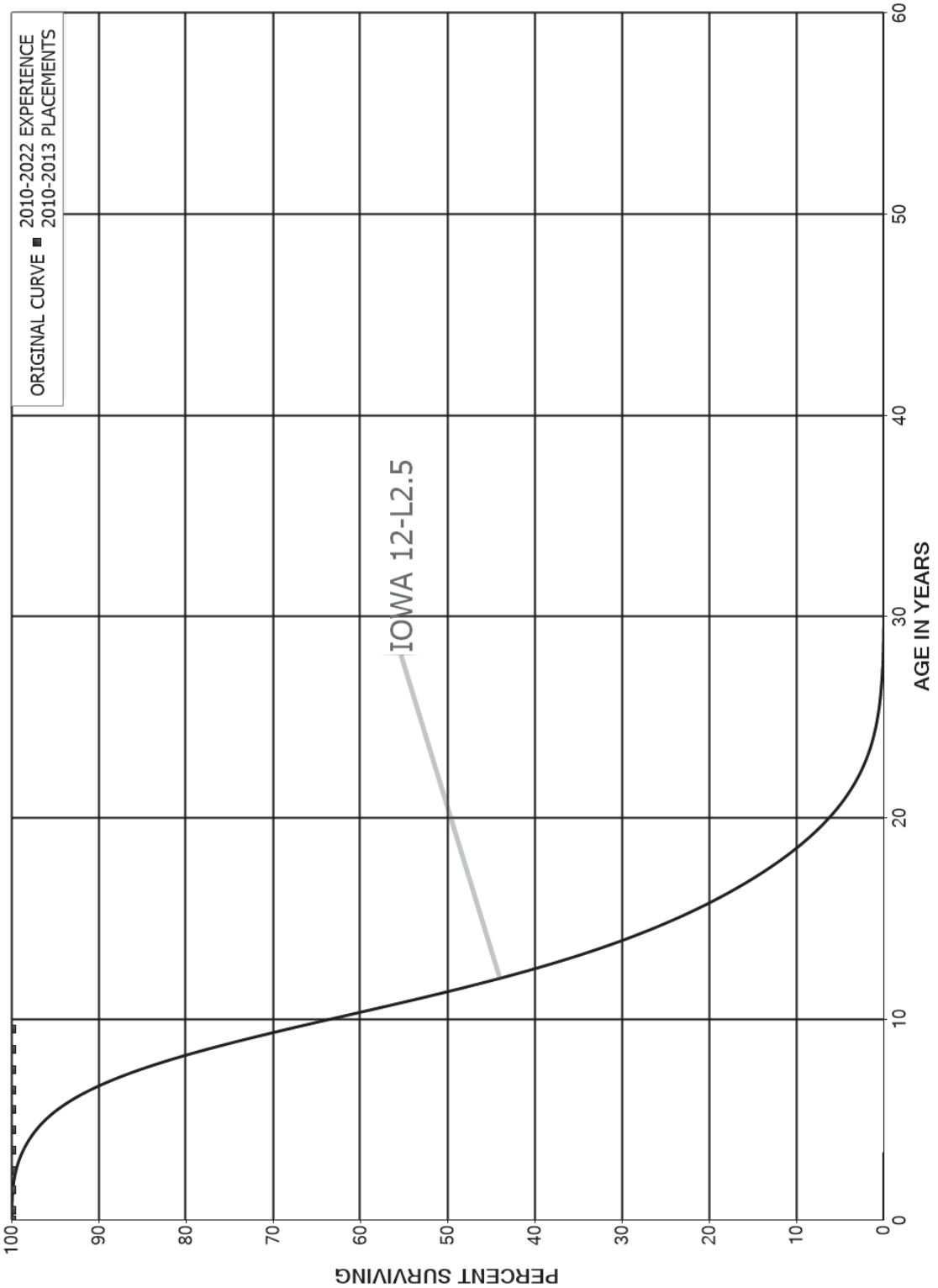
ACCOUNT 391.00 OFFICE FURNITURE AND EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1998-2019 EXPERIENCE BAND 2008-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	31,726		0.0000	1.0000	100.00
0.5	56,179		0.0000	1.0000	100.00
1.5	81,010		0.0000	1.0000	100.00
2.5	82,237		0.0000	1.0000	100.00
3.5	81,092	1,312	0.0162	0.9838	100.00
4.5	76,182	11,545	0.1515	0.8485	98.38
5.5	86,392	19,785	0.2290	0.7710	83.47
6.5	67,056	22,133	0.3301	0.6699	64.36
7.5	45,507	5,972	0.1312	0.8688	43.11
8.5	43,043	3,957	0.0919	0.9081	37.46
9.5	1,287,476	1,249,496	0.9705	0.0295	34.01
10.5	45,213	2,321	0.0513	0.9487	1.00
11.5	42,892	5,003	0.1166	0.8834	0.95
12.5	37,890		0.0000	1.0000	0.84
13.5	31,512	26,022	0.8258	0.1742	0.84
14.5	5,490	3,260	0.5938	0.4062	0.15
15.5	2,230		0.0000	1.0000	0.06
16.5	2,230	2,230	1.0000		0.06
17.5					

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

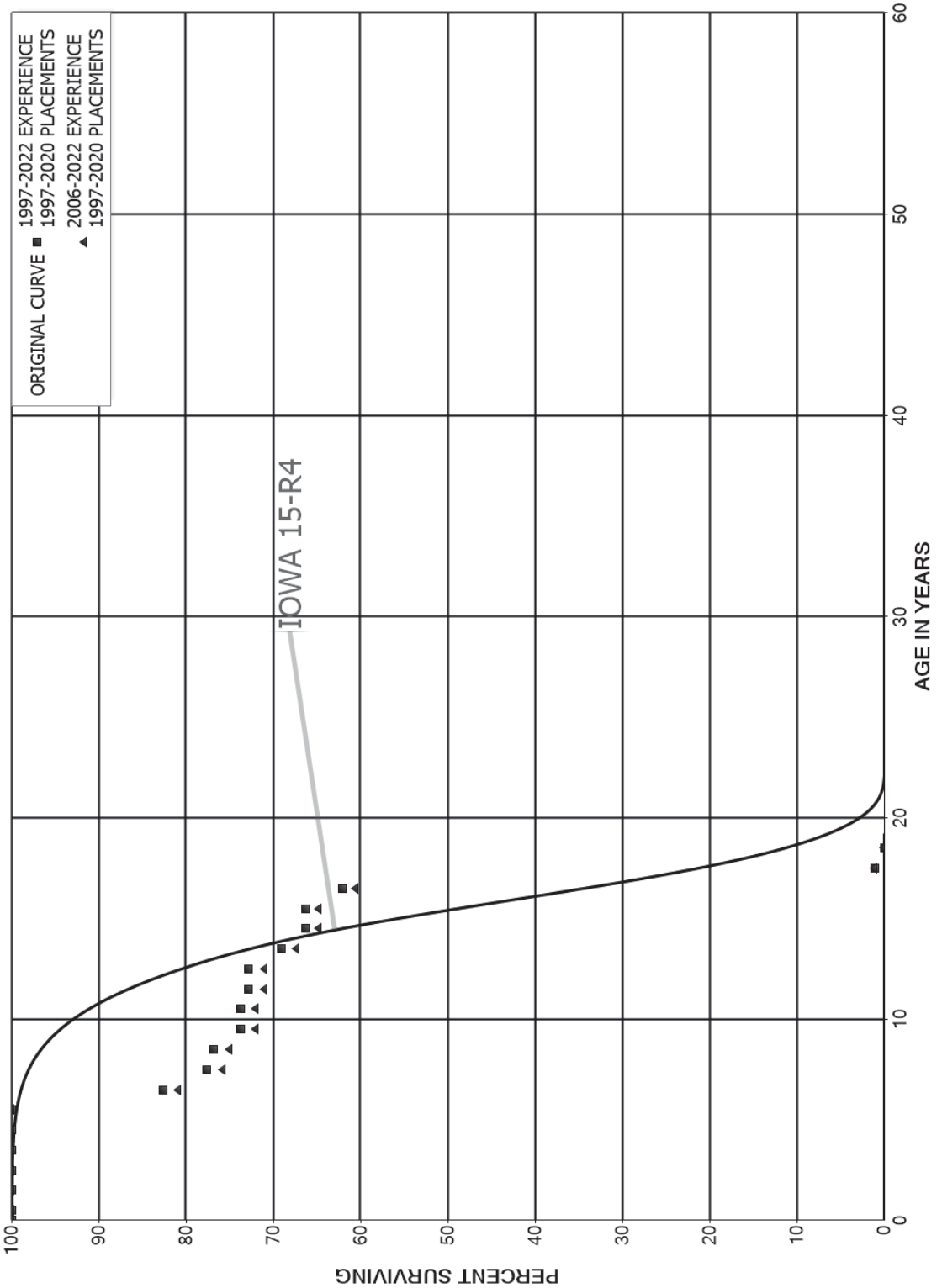
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2010-2013 EXPERIENCE BAND 2010-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,110		0.0000	1.0000	100.00
0.5	4,110		0.0000	1.0000	100.00
1.5	4,110		0.0000	1.0000	100.00
2.5	4,110		0.0000	1.0000	100.00
3.5	27,285		0.0000	1.0000	100.00
4.5	27,285		0.0000	1.0000	100.00
5.5	27,285		0.0000	1.0000	100.00
6.5	27,285		0.0000	1.0000	100.00
7.5	27,285		0.0000	1.0000	100.00
8.5	27,285		0.0000	1.0000	100.00
9.5	4,110		0.0000	1.0000	100.00
10.5	4,110		0.0000	1.0000	100.00
11.5	4,110		0.0000	1.0000	100.00
12.5					100.00

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1997-2020 EXPERIENCE BAND 1997-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	294,305		0.0000	1.0000	100.00
0.5	284,726		0.0000	1.0000	100.00
1.5	284,726		0.0000	1.0000	100.00
2.5	266,735		0.0000	1.0000	100.00
3.5	207,896		0.0000	1.0000	100.00
4.5	207,896		0.0000	1.0000	100.00
5.5	194,549	33,845	0.1740	0.8260	100.00
6.5	160,704	9,738	0.0606	0.9394	82.60
7.5	135,735	1,249	0.0092	0.9908	77.60
8.5	134,486	5,505	0.0409	0.9591	76.88
9.5	128,981		0.0000	1.0000	73.74
10.5	130,913	1,641	0.0125	0.9875	73.74
11.5	129,271		0.0000	1.0000	72.81
12.5	129,271	6,688	0.0517	0.9483	72.81
13.5	122,583	4,819	0.0393	0.9607	69.05
14.5	117,764		0.0000	1.0000	66.33
15.5	117,764	7,626	0.0648	0.9352	66.33
16.5	110,138	108,206	0.9825	0.0175	62.04
17.5	1,932	1,932	1.0000		1.09
18.5					

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

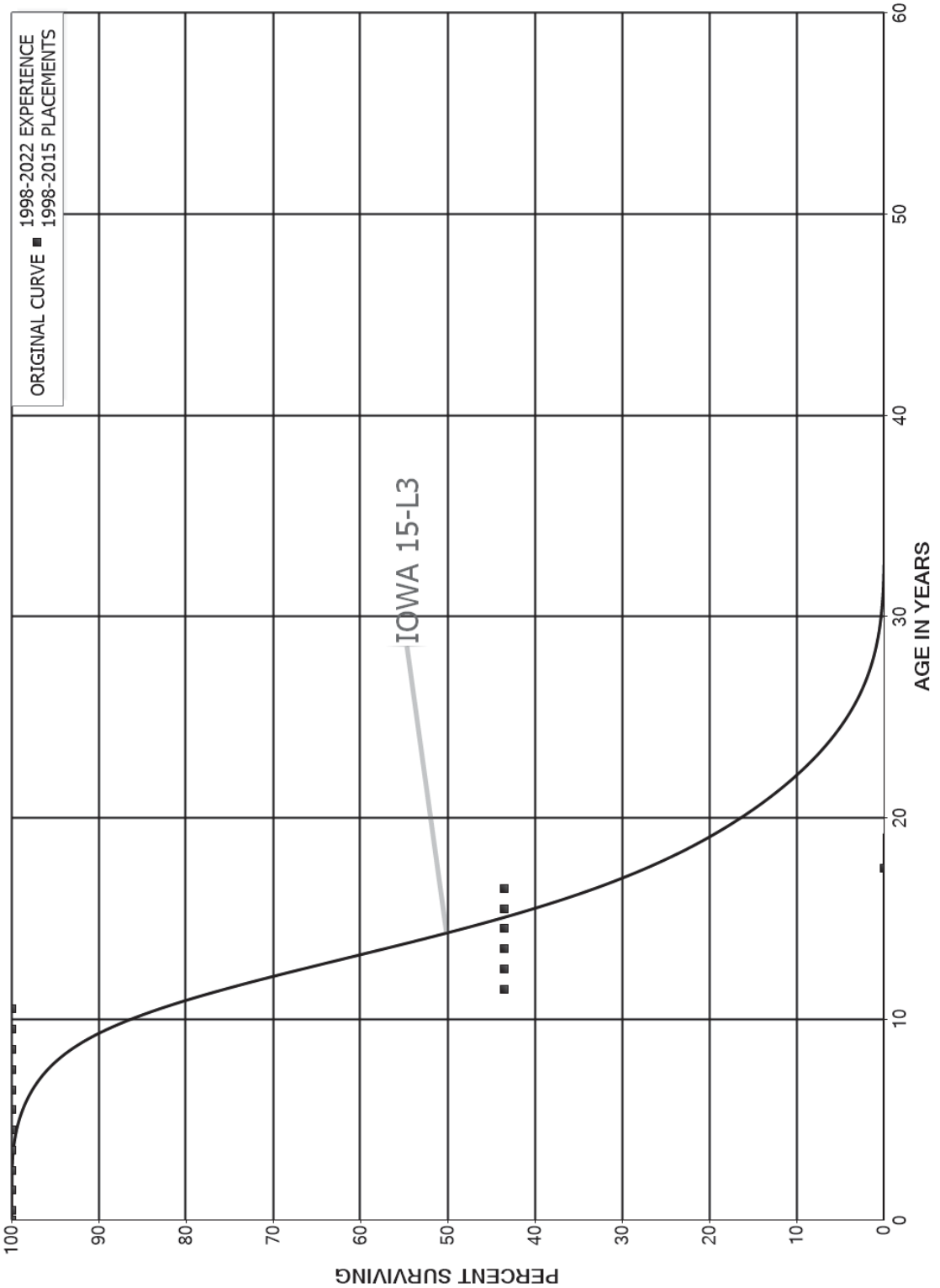
ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1997-2020 EXPERIENCE BAND 2006-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	153,651		0.0000	1.0000	100.00
0.5	144,073		0.0000	1.0000	100.00
1.5	144,073		0.0000	1.0000	100.00
2.5	240,976		0.0000	1.0000	100.00
3.5	182,137		0.0000	1.0000	100.00
4.5	182,137		0.0000	1.0000	100.00
5.5	176,416	33,845	0.1918	0.8082	100.00
6.5	153,558	9,738	0.0634	0.9366	80.82
7.5	130,230	1,249	0.0096	0.9904	75.69
8.5	134,486	5,505	0.0409	0.9591	74.96
9.5	128,981		0.0000	1.0000	71.90
10.5	130,913	1,641	0.0125	0.9875	71.90
11.5	129,271		0.0000	1.0000	70.99
12.5	129,271	6,688	0.0517	0.9483	70.99
13.5	122,583	4,819	0.0393	0.9607	67.32
14.5	117,764		0.0000	1.0000	64.67
15.5	117,764	7,626	0.0648	0.9352	64.67
16.5	110,138	108,206	0.9825	0.0175	60.49
17.5	1,932	1,932	1.0000		1.06
18.5					

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 396.00 POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

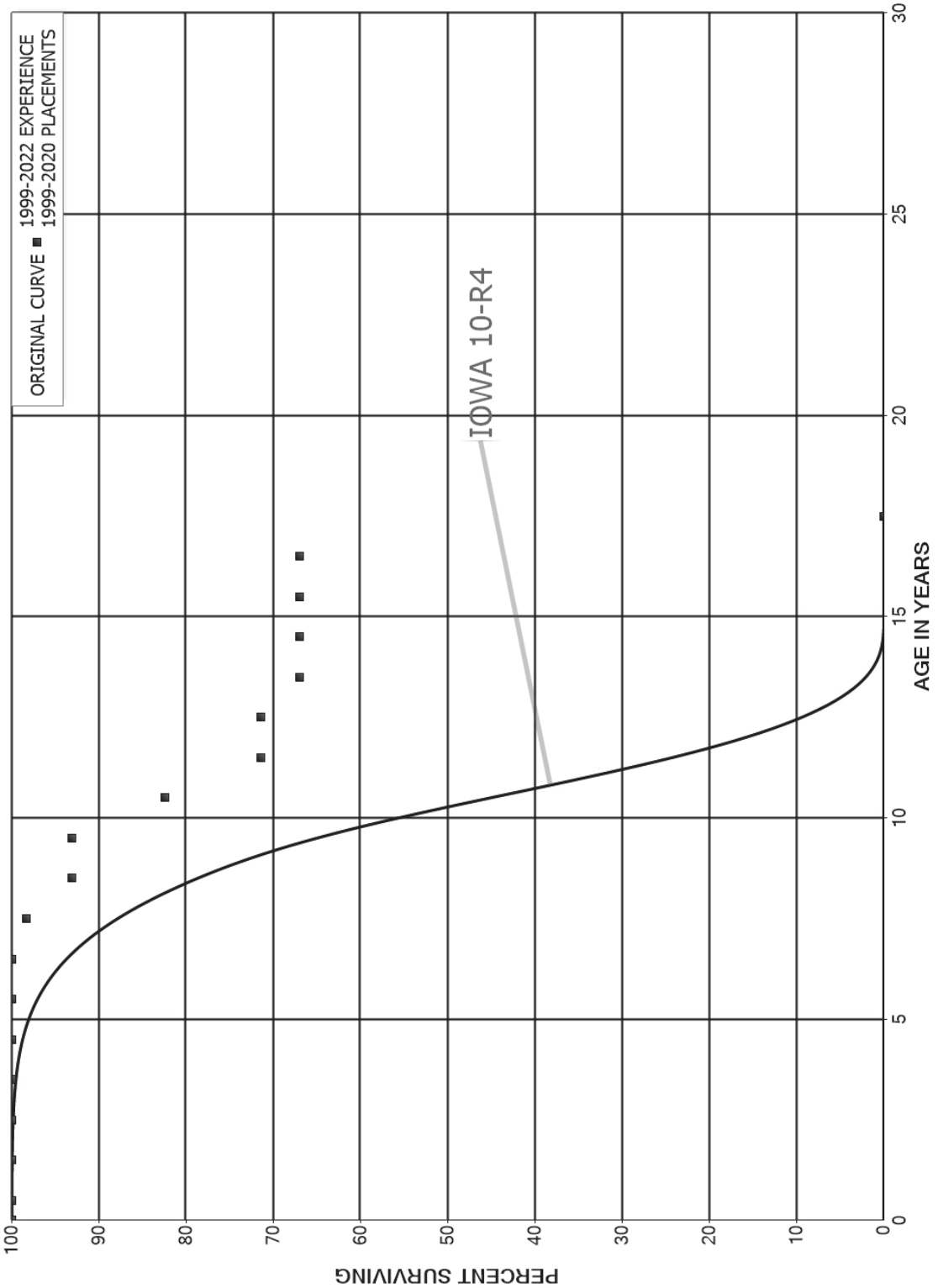
ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1998-2015 EXPERIENCE BAND 1998-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	29,013		0.0000	1.0000	100.00
0.5	29,013		0.0000	1.0000	100.00
1.5	29,013		0.0000	1.0000	100.00
2.5	29,013		0.0000	1.0000	100.00
3.5	29,013		0.0000	1.0000	100.00
4.5	29,013		0.0000	1.0000	100.00
5.5	29,013		0.0000	1.0000	100.00
6.5	29,013		0.0000	1.0000	100.00
7.5	19,534		0.0000	1.0000	100.00
8.5	19,534		0.0000	1.0000	100.00
9.5	19,534		0.0000	1.0000	100.00
10.5	19,534	11,037	0.5650	0.4350	100.00
11.5	8,497		0.0000	1.0000	43.50
12.5	8,497		0.0000	1.0000	43.50
13.5	8,497		0.0000	1.0000	43.50
14.5	8,497		0.0000	1.0000	43.50
15.5	8,497		0.0000	1.0000	43.50
16.5	8,497	8,497	1.0000		43.50
17.5					

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 399.03 OTHER TANGIBLE PROPERTY - NETWORK HARDWARE
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

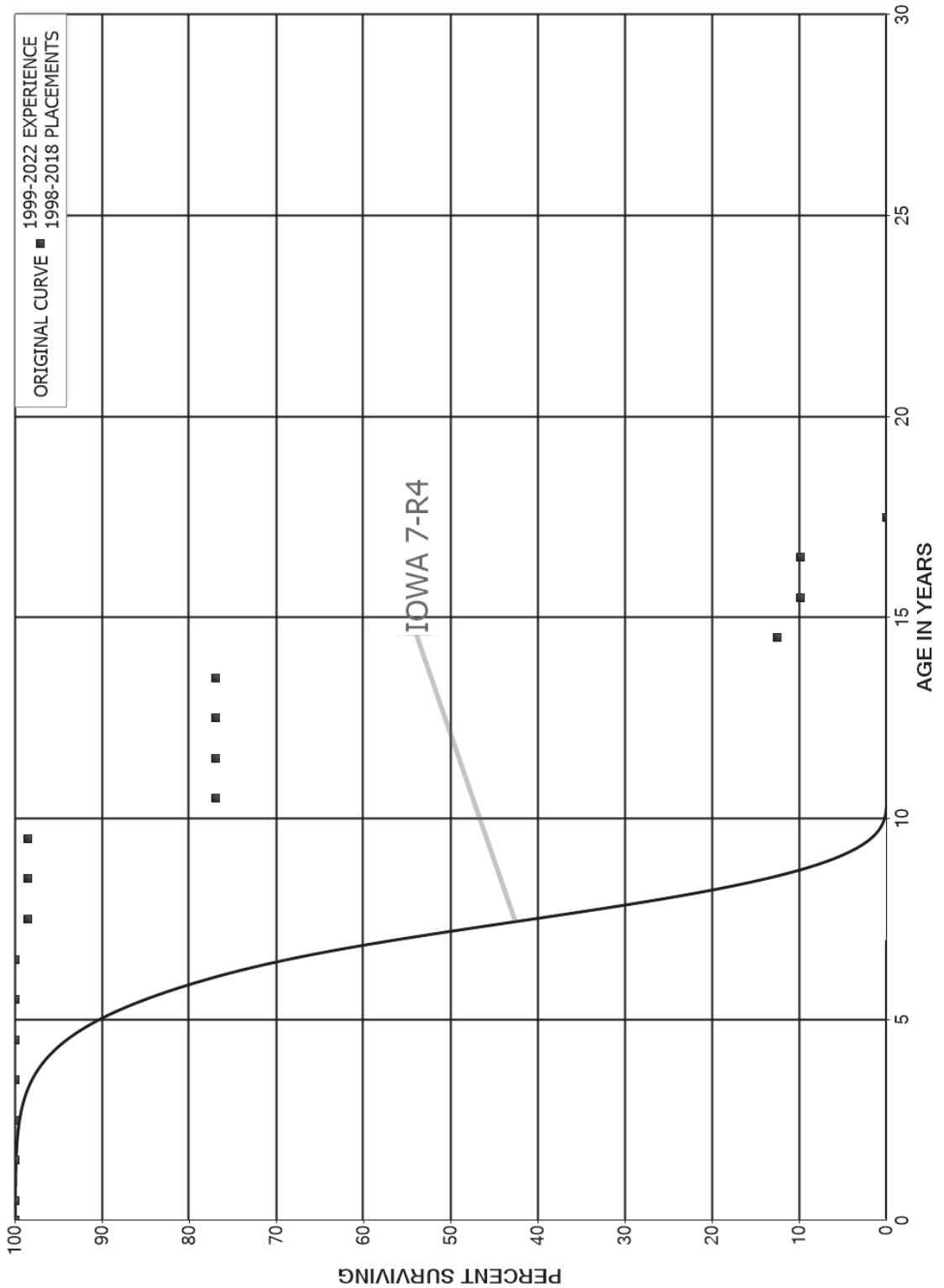
ACCOUNT 399.03 OTHER TANGIBLE PROPERTY - NETWORK HARDWARE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1999-2020 EXPERIENCE BAND 1999-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	283,574		0.0000	1.0000	100.00
0.5	283,574		0.0000	1.0000	100.00
1.5	283,574		0.0000	1.0000	100.00
2.5	279,212		0.0000	1.0000	100.00
3.5	255,308		0.0000	1.0000	100.00
4.5	255,308		0.0000	1.0000	100.00
5.5	255,308		0.0000	1.0000	100.00
6.5	255,308	4,320	0.0169	0.9831	100.00
7.5	250,988	13,274	0.0529	0.9471	98.31
8.5	237,714		0.0000	1.0000	93.11
9.5	234,104	26,829	0.1146	0.8854	93.11
10.5	207,275	27,749	0.1339	0.8661	82.44
11.5	179,526		0.0000	1.0000	71.40
12.5	179,526	11,191	0.0623	0.9377	71.40
13.5	168,335		0.0000	1.0000	66.95
14.5	168,335		0.0000	1.0000	66.95
15.5	168,335		0.0000	1.0000	66.95
16.5	168,335	168,335	1.0000		66.95
17.5					

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 399.07 OTHER TANGIBLE PROPERTY - PC SOFTWARE
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

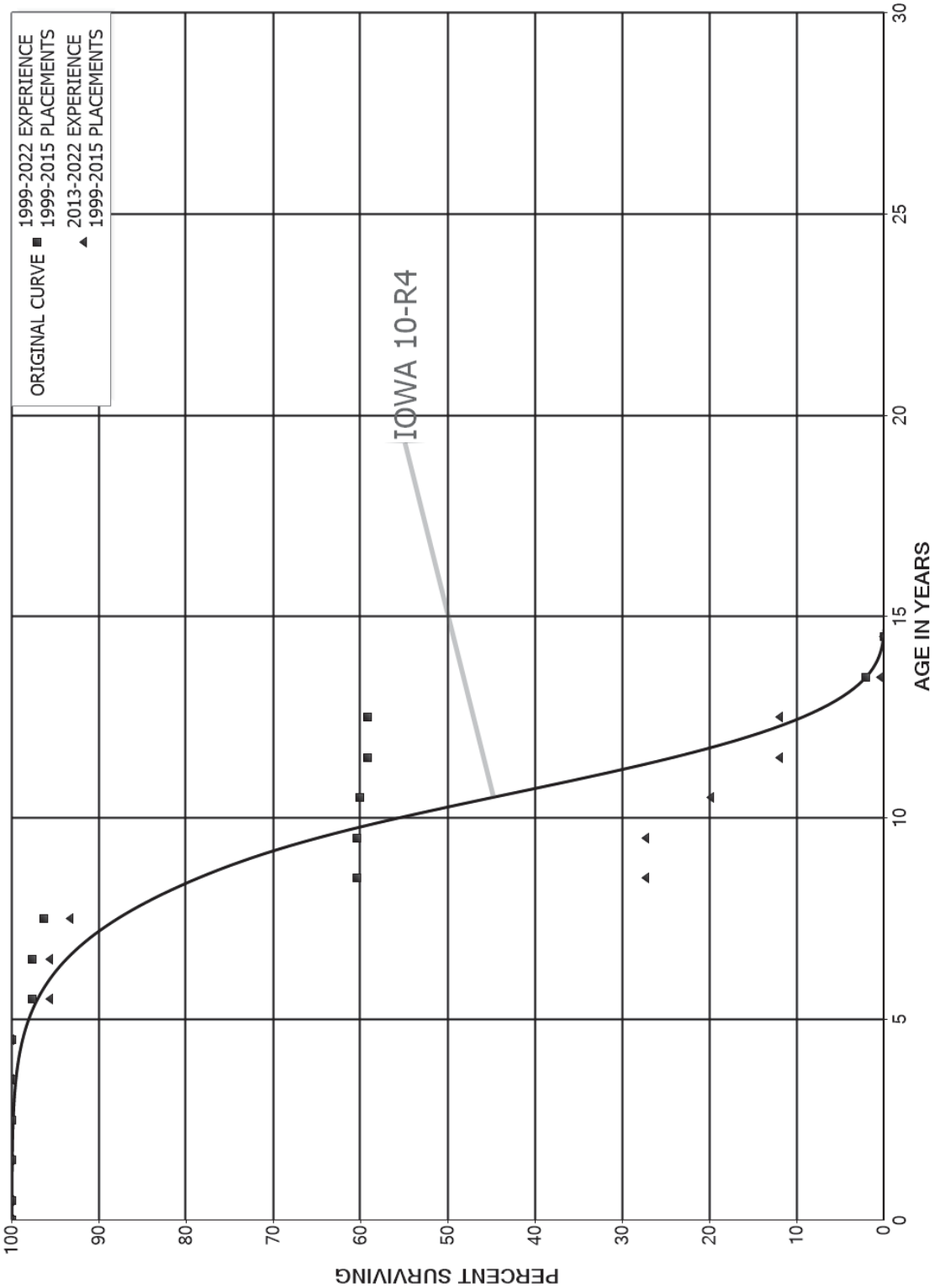
ACCOUNT 399.07 OTHER TANGIBLE PROPERTY - PC SOFTWARE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1998-2018 EXPERIENCE BAND 1999-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	203,853		0.0000	1.0000	100.00
0.5	203,853		0.0000	1.0000	100.00
1.5	203,853		0.0000	1.0000	100.00
2.5	203,853		0.0000	1.0000	100.00
3.5	203,853		0.0000	1.0000	100.00
4.5	160,331		0.0000	1.0000	100.00
5.5	160,331		0.0000	1.0000	100.00
6.5	160,331	2,374	0.0148	0.9852	100.00
7.5	157,956		0.0000	1.0000	98.52
8.5	122,893		0.0000	1.0000	98.52
9.5	122,893	26,948	0.2193	0.7807	98.52
10.5	99,309		0.0000	1.0000	76.92
11.5	99,309		0.0000	1.0000	76.92
12.5	99,309		0.0000	1.0000	76.92
13.5	99,309	83,192	0.8377	0.1623	76.92
14.5	16,117	3,364	0.2087	0.7913	12.48
15.5	12,753		0.0000	1.0000	9.88
16.5	12,753	12,753	1.0000		9.88
17.5					

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
ACCOUNT 399.08 OTHER TANGIBLE PROPERTY - APPLICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 399.08 OTHER TANGIBLE PROPERTY - APPLICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1999-2015 EXPERIENCE BAND 1999-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,606,195		0.0000	1.0000	100.00
0.5	1,606,195		0.0000	1.0000	100.00
1.5	1,606,195		0.0000	1.0000	100.00
2.5	1,606,195		0.0000	1.0000	100.00
3.5	1,606,195		0.0000	1.0000	100.00
4.5	1,606,195	38,575	0.0240	0.9760	100.00
5.5	1,567,620		0.0000	1.0000	97.60
6.5	1,567,620	20,641	0.0132	0.9868	97.60
7.5	1,528,248	569,994	0.3730	0.6270	96.31
8.5	958,254		0.0000	1.0000	60.39
9.5	739,111	4,418	0.0060	0.9940	60.39
10.5	734,693	10,700	0.0146	0.9854	60.03
11.5	723,993		0.0000	1.0000	59.16
12.5	723,993	699,377	0.9660	0.0340	59.16
13.5	24,616	24,616	1.0000		2.01
14.5					

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 399.08 OTHER TANGIBLE PROPERTY - APPLICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1999-2015 EXPERIENCE BAND 2013-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	828,509		0.0000	1.0000	100.00
0.5	867,085		0.0000	1.0000	100.00
1.5	867,085		0.0000	1.0000	100.00
2.5	867,085		0.0000	1.0000	100.00
3.5	867,085		0.0000	1.0000	100.00
4.5	867,085	38,575	0.0445	0.9555	100.00
5.5	828,509		0.0000	1.0000	95.55
6.5	832,927	20,641	0.0248	0.9752	95.55
7.5	804,255	569,994	0.7087	0.2913	93.18
8.5	234,261		0.0000	1.0000	27.14
9.5	16,084	4,418	0.2747	0.7253	27.14
10.5	26,971	10,700	0.3967	0.6033	19.69
11.5	16,271		0.0000	1.0000	11.88
12.5	714,681	699,377	0.9786	0.0214	11.88
13.5	24,616	24,616	1.0000		0.25
14.5					

PART VIII. NET SALVAGE STATISTICS

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 391.00 OFFICE FURNITURE AND EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2008	1,287,606		0		0		0
2009							
2010	7,889		0		0		0
2011							
2012							
2013							
2014	22,133		0		0		0
2015	2,230		0		0		0
2016	1,106		0		0		0
2017							
2018	2,788		0		0		0
2019							
2020	27,249		0		0		0
2021	2,033		0		0		0
2022							
TOTAL	1,353,035		0		0		0
THREE-YEAR MOVING AVERAGES							
08-10	431,832		0		0		0
09-11	2,630		0		0		0
10-12	2,630		0		0		0
11-13							
12-14	7,378		0		0		0
13-15	8,121		0		0		0
14-16	8,490		0		0		0
15-17	1,112		0		0		0
16-18	1,298		0		0		0
17-19	929		0		0		0
18-20	10,012		0		0		0
19-21	9,761		0		0		0
20-22	9,761		0		0		0
FIVE-YEAR AVERAGE							
18-22	6,414		0		0		0

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2016				5,024		5,024	
2017							
2018							
2019							
2020							
2021							
2022							
TOTAL				5,024		5,024	
THREE-YEAR MOVING AVERAGES							
16-18				1,675		1,675	
17-19							
18-20							
19-21							
20-22							
FIVE-YEAR AVERAGE							
18-22							

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2006	15,243		0		0		0
2007	1,249		0	48	4	48	4
2008							
2009	1,641		0		0		0
2010							
2011							
2012							
2013	419-		0		0		0
2014							
2015							
2016	16,246		0		0		0
2017							
2018							
2019							
2020	132,230		0		0		0
2021	15,060		0		0		0
2022							
TOTAL	181,250		0	48	0	48	0
THREE-YEAR MOVING AVERAGES							
06-08	5,497		0	16	0	16	0
07-09	963		0	16	2	16	2
08-10	547		0		0		0
09-11	547		0		0		0
10-12							
11-13	140-		0		0		0
12-14	140-		0		0		0
13-15	140-		0		0		0
14-16	5,415		0		0		0
15-17	5,415		0		0		0
16-18	5,415		0		0		0
17-19							
18-20	44,077		0		0		0
19-21	49,096		0		0		0
20-22	49,096		0		0		0
FIVE-YEAR AVERAGE							
18-22	29,458		0		0		0

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2015	8,497		0		0		0
2016							
2017							
2018							
2019							
2020							
2021	11,037		0		0		0
2022							
TOTAL	19,534		0		0		0
THREE-YEAR MOVING AVERAGES							
15-17	2,832		0		0		0
16-18							
17-19							
18-20							
19-21	3,679		0		0		0
20-22	3,679		0		0		0
FIVE-YEAR AVERAGE							
18-22	2,207		0		0		0

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 399.03 OTHER TANGIBLE PROPERTY - NETWORK HARDWARE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2013	42,340		0		0		0
2014							
2015							
2016	209,358		0		0		0
2017							
2018							
2019							
2020							
2021							
2022							
TOTAL	251,698		0		0		0
THREE-YEAR MOVING AVERAGES							
13-15	14,114		0		0		0
14-16	69,786		0		0		0
15-17	69,786		0		0		0
16-18	69,786		0		0		0
17-19							
18-20							
19-21							
20-22							
FIVE-YEAR AVERAGE							
18-22							

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 399.07 OTHER TANGIBLE PROPERTY - PC SOFTWARE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2013	88,815		0		0		0
2014							
2015							
2016	39,816		0		0		0
2017							
2018							
2019							
2020							
2021							
2022							
TOTAL	128,631		0		0		0
THREE-YEAR MOVING AVERAGES							
13-15	29,605		0		0		0
14-16	13,272		0		0		0
15-17	13,272		0		0		0
16-18	13,272		0		0		0
17-19							
18-20							
19-21							
20-22							
FIVE-YEAR AVERAGE							
18-22							

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 399.08 OTHER TANGIBLE PROPERTY - APPLICATION SOFTWARE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2013	707,722		0		0		0
2014							
2015							
2016	31,388		0		0		0
2017	38,575		0		0		0
2018							
2019							
2020							
2021	590,635		0		0		0
2022							
TOTAL	1,368,321		0		0		0
THREE-YEAR MOVING AVERAGES							
13-15	235,907		0		0		0
14-16	10,463		0		0		0
15-17	23,321		0		0		0
16-18	23,321		0		0		0
17-19	12,858		0		0		0
18-20							
19-21	196,878		0		0		0
20-22	196,878		0		0		0
FIVE-YEAR AVERAGE							
18-22	118,127		0		0		0

PART IX. DETAILED DEPRECIATION CALCULATIONS

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 390.01 STRUCTURES AND IMPROVEMENTS - FRAME

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. -10						
2002	143,668.72	66,375	10,585	147,451	23.20	6,356
2003	35,669.80	15,754	2,512	36,725	23.94	1,534
	179,338.52	82,129	13,097	184,175		7,890

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.3 4.40

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 390.04 STRUCTURES AND IMPROVEMENTS - AIR CONDITIONING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R2						
NET SALVAGE PERCENT.. -10						
1998	5,771.00	5,938	6,348			
2016	9,612.91	3,729	4,505	6,069	9.71	625
	15,383.91	9,667	10,853	6,069		625

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.7 4.06

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 390.09 STRUCTURES AND IMPROVEMENTS - IMPROVEMENTS - LEASED

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R3						
NET SALVAGE PERCENT.. 0						
1999	38,834.00	33,494	38,834			
	38,834.00	33,494	38,834			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 391.00 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R3						
NET SALVAGE PERCENT.. 0						
2009	6,377.62	3,763	1,851	4,527	8.20	552
2015	2,949.48	1,013	498	2,451	13.13	187
2018	15,143.80	3,112	1,530	13,614	15.89	857
2019	2,457.03	388	191	2,266	16.84	135
	26,927.93	8,276	4,070	22,858		1,731

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.2 6.43

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-L2.5						
NET SALVAGE PERCENT.. +5						
2010	4,109.69	2,574	2,330	1,574	4.09	385
2013	23,175.00	13,191	11,942	10,074	4.81	2,094
	27,284.69	15,765	14,272	11,648		2,479

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.7 9.09

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R4						
NET SALVAGE PERCENT.. 0						
2015	15,231.55	7,199	8,864	6,368	7.91	805
2017	13,346.43	4,627	5,698	7,648	9.80	780
2019	58,839.38	12,709	15,649	43,190	11.76	3,673
2020	22,810.06	3,406	4,194	18,616	12.76	1,459
	110,227.42	27,941	34,405	75,822		6,717

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.3 6.09

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L3						
NET SALVAGE PERCENT.. +5						
2015	9,478.52	4,142	1,015	7,990	8.10	986
	9,478.52	4,142	1,015	7,990		986

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.1 10.40

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 399.03 OTHER TANGIBLE PROPERTY - NETWORK HARDWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 10-R4						
NET SALVAGE PERCENT.. 0						
2019	23,903.89	7,697	5,989	17,915	6.78	2,642
2020	4,362.55	977	760	3,603	7.76	464
	28,266.44	8,674	6,749	21,517		3,106

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.9 10.99

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 399.07 OTHER TANGIBLE PROPERTY - PC SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-R4						
NET SALVAGE PERCENT.. 0						
2014	35,063.77	32,158	31,180	3,884	0.58	3,884
2018	43,521.91	25,367	24,596	18,926	2.92	6,482
	78,585.68	57,525	55,776	22,810		10,366

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.2 13.19

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE

ACCOUNT 399.08 OTHER TANGIBLE PROPERTY - APPLICATION SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 10-R4						
NET SALVAGE PERCENT.. 0						
2013	219,143.35	178,383	180,017	39,126	1.86	21,035
2015	18,731.46	12,681	12,797	5,934	3.23	1,837
	237,874.81	191,064	192,814	45,061		22,872

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.0 9.62

ATMOS ENERGY CORPORATION

SHARED SERVICES UNIT

DEPRECIATION RATE STUDY

As of September 30, 2022



http://www.utilityalliance.com

ATMOS ENERGY CORPORATION - SHARED SERVICES UNIT
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY

Atmos Energy Corporation ("Atmos" or "Company") engaged Alliance Consulting Group to conduct a depreciation study of the Company's Shared Services Unit ("SSU" or "Shared Services") operations depreciable assets as of fiscal year end September 30, 2022. SSU provides support to Atmos' regulated utility divisions.

The regulated natural gas utility divisions during the year ended September 30, 2022 were:

- Atmos Colorado-Kansas Division
- Atmos Louisiana Division
- Atmos Kentucky Mid-States (Kentucky, Tennessee, and Virginia) Division
- Atmos Mississippi Division
- Atmos Mid-Tex Division
- Atmos West Texas Division
- Atmos Pipeline Texas Division

The depreciation rates are based on the straight-line method, equal life group ("ELG") procedure, and remaining-life technique. This study results in an annual depreciation expense accrual of $28.9 million when applied to depreciable plant balances as of September 30, 2022.

The depreciation study we conducted analyzed and developed depreciation recommendations at an account level. The resulting annual depreciation accrual amount and depreciation rates contained in this study are at the account level. The Company will accrue depreciation expense based on the account level depreciation rates developed in this study. Appendix A provides the annual depreciation expense. Appendix B provides the calculation of annual depreciation accrual expense and rates. Appendix C provides the proposed depreciation parameters. Appendix D provides the net salvage analysis.

ATMOS ENERGY CORPORATION
SHARED SERVICES UNIT
DEPRECIATION RATE STUDY
As of September 30, 2022
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PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable property as recorded on Shared Services' books at September 30, 2022. The account based depreciation rates were designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of Shared Services' property on a straight-line basis. Non-depreciable property and property that is amortized, such as intangibles, were excluded from this study.

Shared Services is a division of Atmos Corporation dedicated to providing various support services to its operating companies. Shared Services consists of two Divisions, Division 02 – General Office and Division 12 – Customer Support. For purposes of this study, Division 02 and Division 12 were combined for analysis and rate calculations. As of the study date, Shared Services supported regulated gas utility divisions operating in eight different states.

STUDY RESULTS

The current study's annual depreciation expense results from the use of Iowa Curve dispersion patterns with average service lives over a straight-line basis as well as the equal life group ("ELG") procedure and remaining-life technique. Consideration was given to appropriate net salvage factors in the development of the study recommended depreciation rates. Detailed information for each of these factors will follow in this report.

Overall depreciation rates for Shared Services depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual of $28.9 million based on Shared Services' depreciable investment at September 30, 2022.

The recommended annual depreciation accrual rates and expense are shown in Appendix A. Appendix B presents the development of the depreciation rates and annual accruals. Appendix C presents the recommended study mortality and net salvage parameters by account. Appendix D shows net salvage history by plant account.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during a particular period. The Company accrues depreciation based on original cost of all depreciable property included in each functional property group. On retirement the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

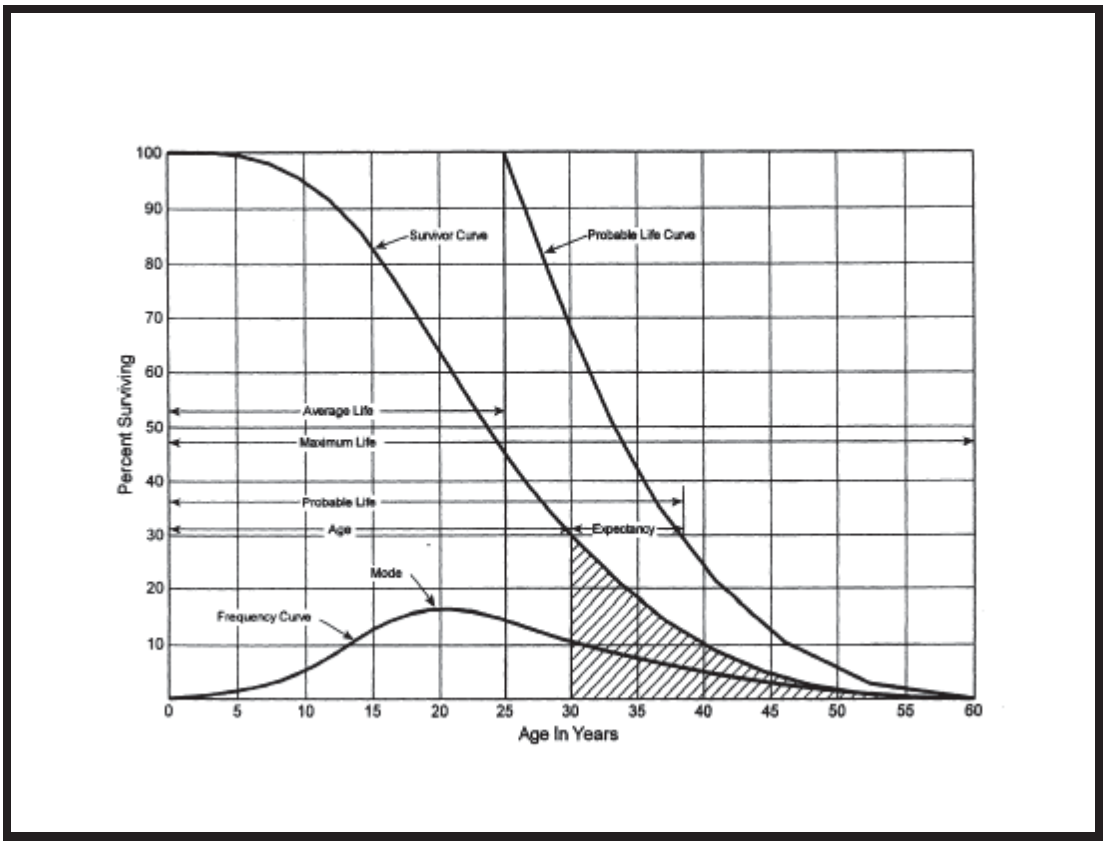
Basis of Depreciation Estimates

The straight-line, ELG, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective equal life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual depreciation rates are shown in Appendix B and remaining life calculations are provided in the workpapers.

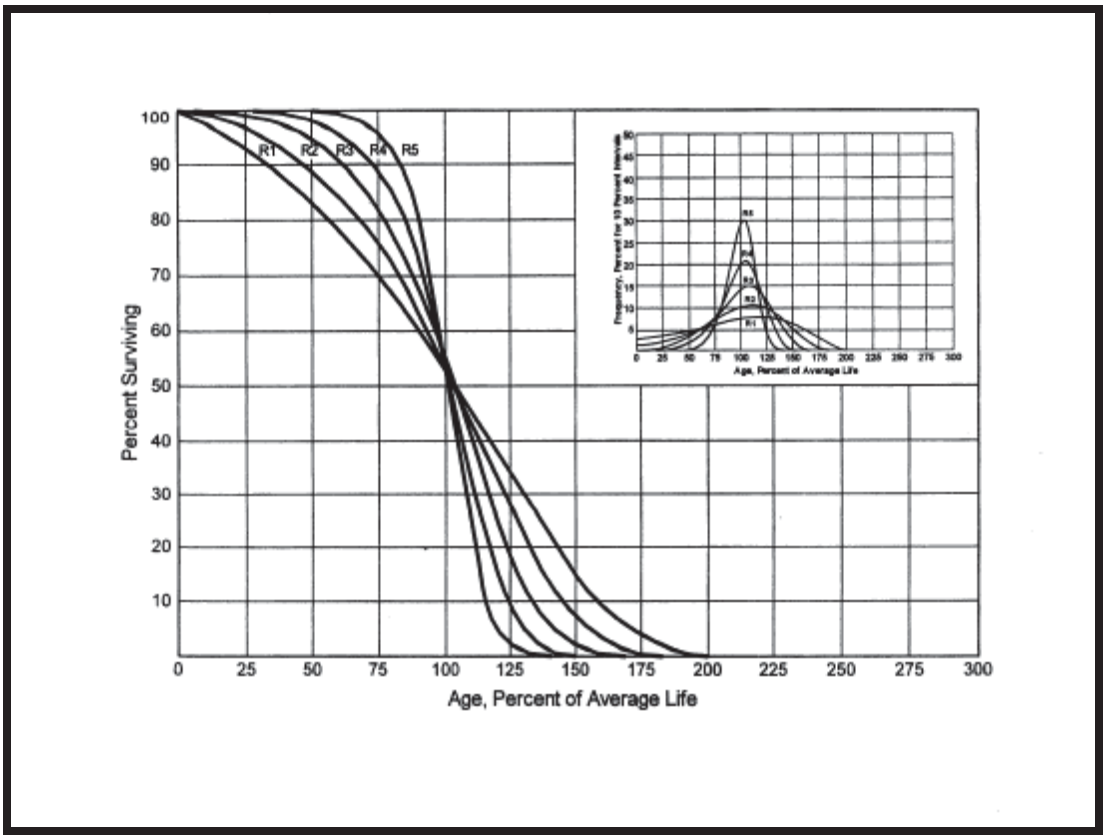
Actuarial analysis was used with each account within a function, where sufficient data was available, and judgment was used to some degree on all accounts.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of “R” moded curves is shown below.



Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. An "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. A special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an

"L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Where data was available, accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. The results from these analyses for those accounts which had data sufficient to be analyzed using this method are shown in the Life Analysis section of this report.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least for example, any analysis requires choosing which bands to place more emphasis.

The establishment of appropriate average service lives and retirement dispersions for Shared Services' accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Equal Life Group Depreciation

Atmos agreed that the continued use of the ELG depreciation procedure was appropriate. This study uses the ELG depreciation procedure to group the assets within each account. After an average service life and dispersion were selected for each account, those parameters were used to estimate what portion of the surviving investment of each vintage was expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ELG groups are defined by their respective account dispersion, life, and net salvage estimates. A straight-line rate for each ELG group is computed and accumulated across each vintage. The resulting rate for each ELG group is designed to recover all retirements less net salvage as each vintage retires. The ELG procedure recovers net book cost over the life of each ELG group rather than averaging many components. It also closely matches the concept of component or item accounting found in all accounting textbooks.

Theoretical Depreciation Reserve

The Company's book depreciation reserves were reallocated based on the theoretical reserves for each account. This study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical

reserve ratio for each vintage. The equal life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the vintage is retired. Estimated average service lives and dispersion determine the amount within each equal life group. The equal life group-remaining-life theoretical reserve ratio (RRELG) is calculated as:

$$RRELG = 1 - \frac{(ELG\ Remaining\ Life)}{(ELG\ Life)} * (1 - Net\ Salvage\ Ratio)$$

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and documenting the corresponding recommendations.

During the Phase 1 data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Further discussion on data review and adjustment is found in the Salvage Considerations Section of this study. Also as part of the Phase 1 data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion of this study in the life analysis and salvage analysis sections and also in workpapers.

Phase 2 is where the actuarial analysis is performed. Phases 2 and 3 overlap to a significant degree. The detailed property records information is used in Phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in Phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. This information was then carried forward into Phase 3 for the evaluation process.

Phase 3 is the evaluation process which synthesizes analysis, interviews, and operational characteristics into a final selection of asset lives and net salvage parameters. The historical analysis from Phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved calculating accrual rates, making recommendations, and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix B. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[1] documents the steps used in conducting this study. Depreciation Systems, page 289 documents the same basic processes in performing a depreciation study which are: statistical analyses, evaluation of statistical analysis, discussions with management, forecast assumptions, write logic supporting forecasts and estimation, and write final report.

[1] Public Utility Finance & Accounting, A Reader

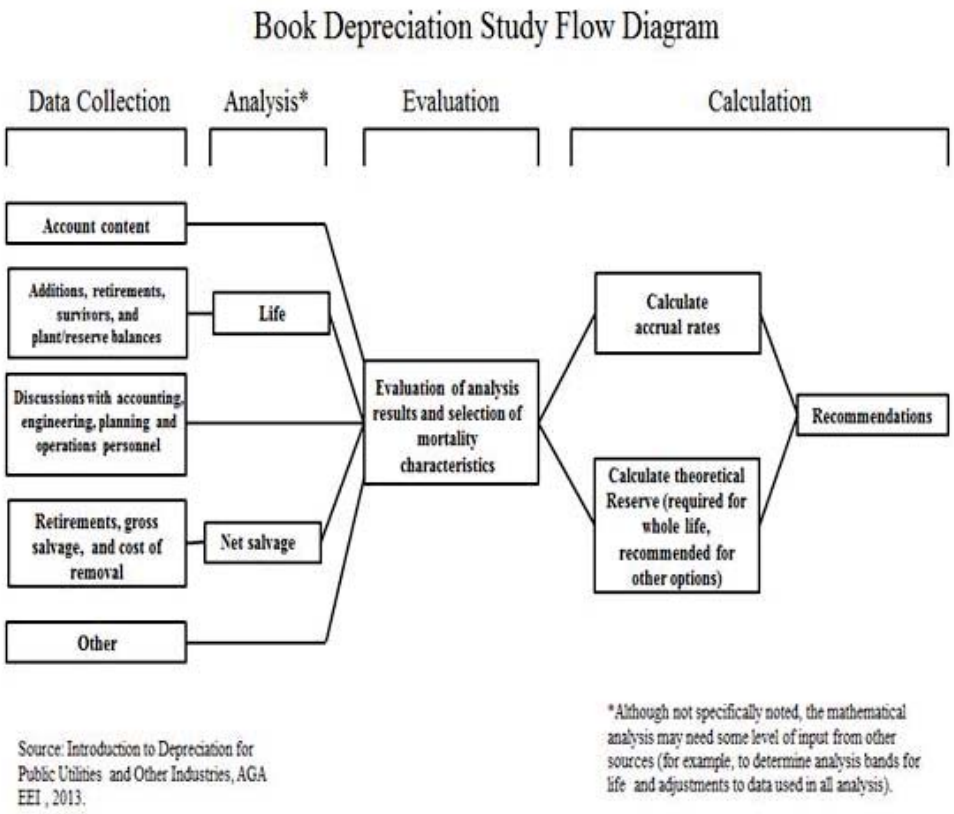


Figure 1

SHARED SERVICES DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation

Annual depreciation expense amounts for the depreciable property accounts of Shared Services were calculated by the straight line, equal life group, and remaining-life system. With this approach, remaining lives were calculated according to standard ELG group expectancy techniques, using the Iowa Curves noted in the calculation. For each plant account, the difference between the surviving investment, adjusted for estimated net salvage and the allocated book depreciation reserve, was divided by the average remaining life to yield the annual depreciation expense. These calculations are shown in Appendix B.

Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group was based on engineering judgment that incorporated available accounting information analyzed using the actuarial methods. After establishment of appropriate average service lives and retirement dispersions, remaining lives were computed for each account. The theoretical depreciation reserve with zero net salvage (used in calculating remaining life) was calculated using theoretical reserve ratios as defined in the theoretical reserve portion of the general discussion section. The difference between plant balance and theoretical reserve was then spread over the ELG depreciation accruals. After accumulating the ELG accruals across each vintage, the annual accrual was divided into the net balance to compute remaining life. Details of the theoretical reserve computations, ELG accruals, and remaining life are found by account in the study workpapers.

LIFE ANALYSIS

The retirement rate ("actuarial") analysis method was applied to all accounts for Shared Services. For each account, an actuarial analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Curves to obtain the most appropriate match. A selected curve for each account is shown in the Life Analysis Section of this report. The observed life tables for all analyzed placement and experience bands are provided in workpapers.

For the overall band (i.e., placement from earliest vintage year, which varied for each account, through 2022) for each account, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (i.e., L, S, or R) as a better match than others. The next step would be to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall experience band, different experience bands were plotted and analyzed, for instance 1988-2022, 2003-2022, 2008-2022, etc. Next, placement bands of varying width were plotted with each experience band discussed above. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. The goal of visual matching was to minimize the differential between the observed life table and Iowa Curve in top- and mid-range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

Due to the nature of the Shared Services Division and the allocation of costs among numerous entities and across various state regulatory jurisdictions, the study does not make a comparison of approved to proposed depreciation rates, due to timing differences and the possibility of changes from the various regulatory agencies approving rates. Instead, we will provide the proposed parameters for the current study (2022) in the account discussions below.

NET SALVAGE CONSIDERATIONS

When a capital asset is retired, physically removed from service and finally disposed of, terminal retirement is said to have occurred. The residual value of a terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset).

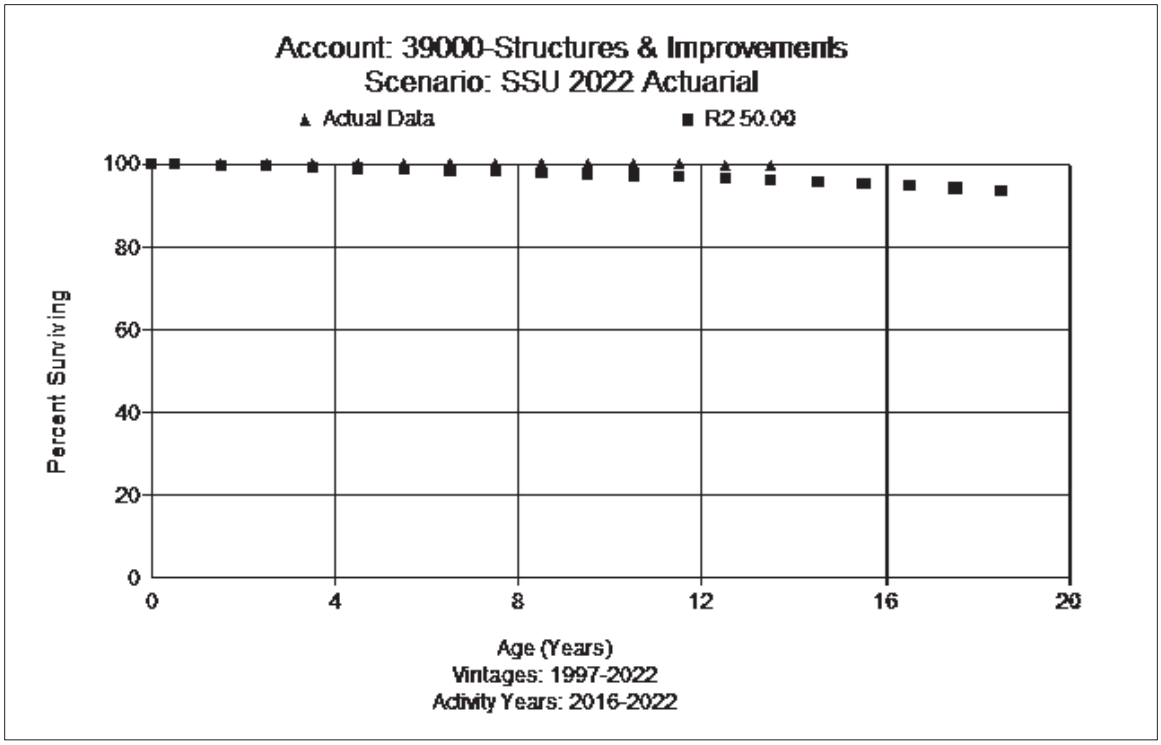
Net Salvage Characteristics

The net salvage analysis for each account is shown in Appendix D. Moving averages for intervals are also included in Appendix D. The assets of Shared Services generally do not incur cost of removal, and salvage has declined in recent years. In this study a zero percent net salvage is recommended for each account, with the exception of Account 392, Transportation Equipment.

Account Life and Net Salvage Analysis

Account 39000 – Structures & Improvements

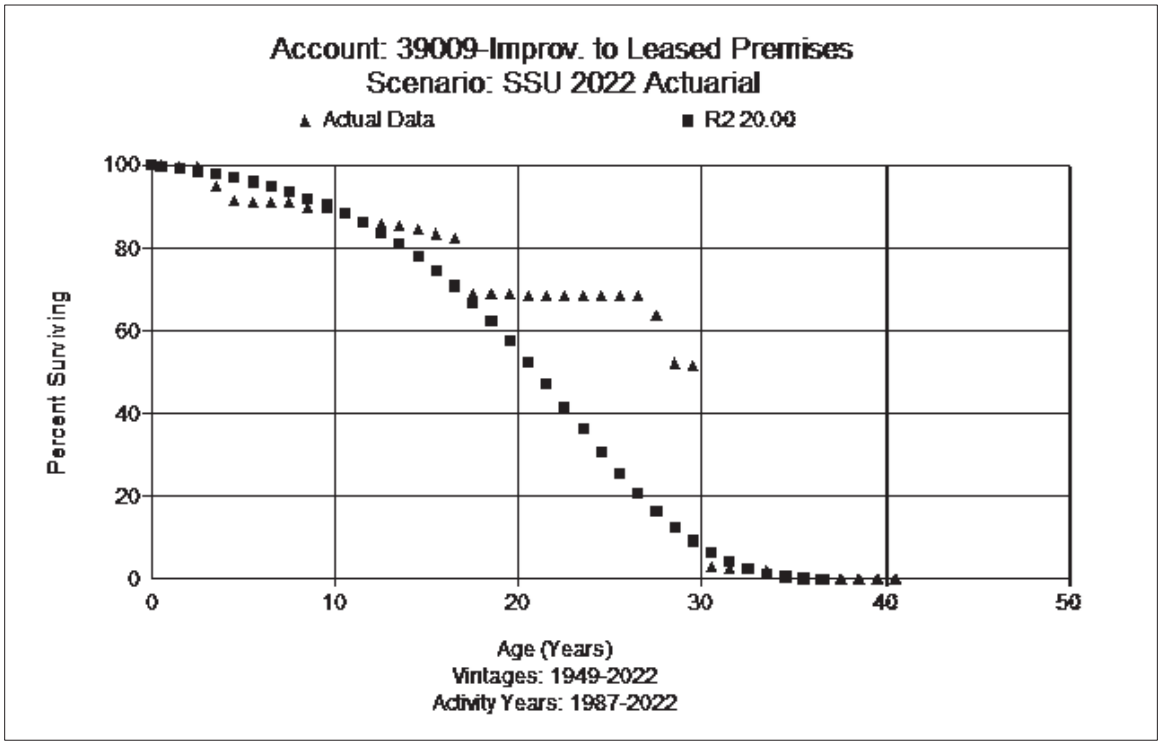
This account includes the cost of buildings and improvements including the Greenville operations center, the Charles K. Vaughn training center, and the call center in Waco. The account balance is approximately $46.1 million. The current average age of investment is 9.83 years. There have been some retirements recorded, but they are in recent years. The current mix of assets is weighted to the longer-lived buildings. Based on judgment and type of assets, this study recommends a 50 year life with the R2 dispersion pattern. A graph of the observed life table and the recommended life and curve are shown below.



Little to no salvage is expected. Some cost of removal is expected at the end of life for some of the assets, but none has been recorded. Therefore, a zero percent net salvage is recommended at this time.

Account 39009 – Improvements to Leased Premises

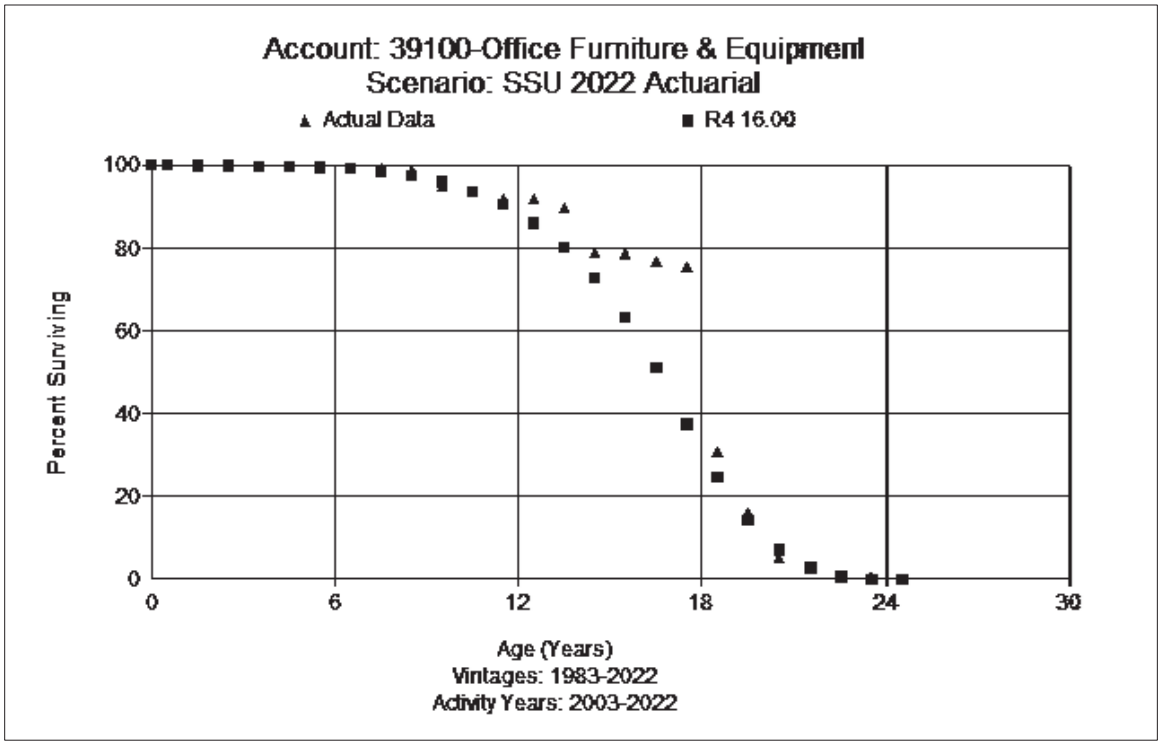
This account includes the cost of improvements to leased premises such as the Dallas office and call centers. The balance is approximately $12.9 million. Assets in this account are tied to their lease term, which is 20 years with renewal options. This study recommends the 20 R2 at this time. A graph of the observed life table and the recommended life and curve are shown below.



No salvage or removal cost has been recorded and none is expected in the future. Therefore, a zero percent net salvage is recommended for this account.

Account 39100 – Office Furniture and Equipment

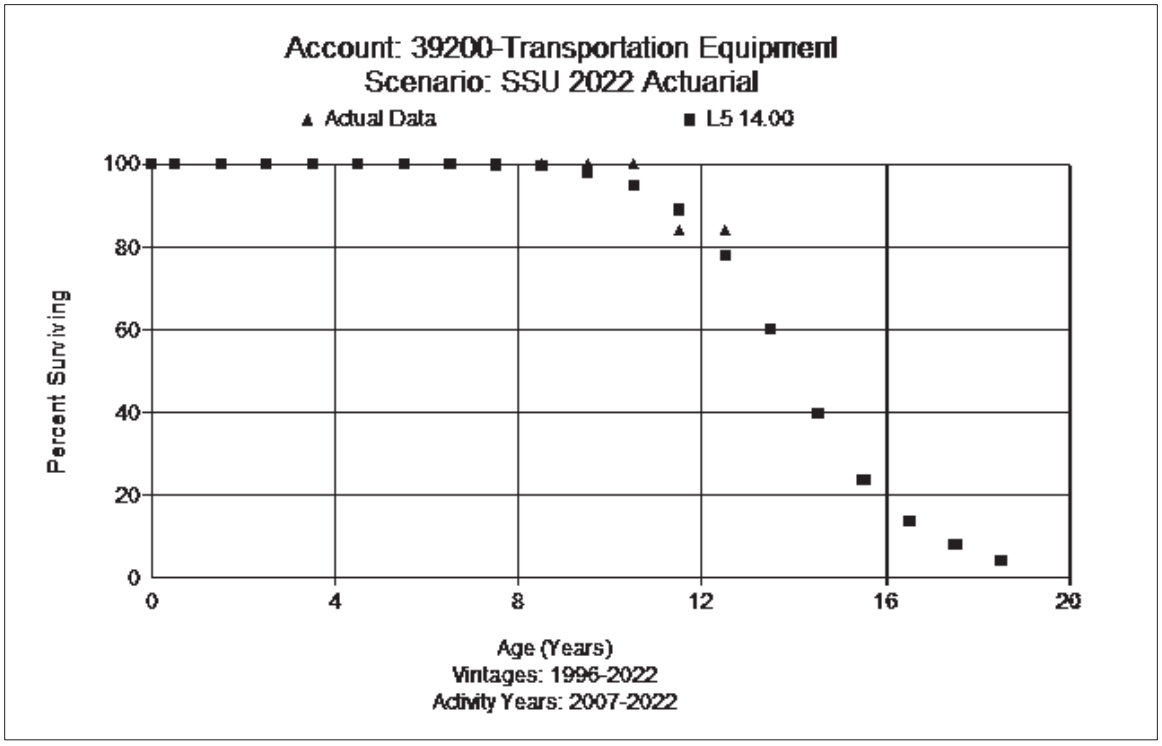
This account consists of modular furniture, desks, chairs, bookcases, credenzas, file cabinets, office machines, and other miscellaneous equipment located at the various locations. The balance is $9.7 million. An expected life range for the assets in this account is 15 to 20 years or longer. The analysis indicates that the assets are experiencing a life of approximately 16-17 years and that the average age of retirements is 17.42 years. Approximately $4.6 million has been retired between 2017 and 2022. Company personnel indicate that some offices were renovated and that more retirements have occurred than in the past. Based on the analysis and future expectations, this study recommends a 16 R4 dispersion pattern. A graph of the observed life table and the recommended life and curve are shown below.



There is no cost of removal, and no salvage has been recorded since 1997. No salvage is expected at retirement in the future. A zero percent net salvage rate is recommended for this account.

Account 39200 – Transportation Equipment

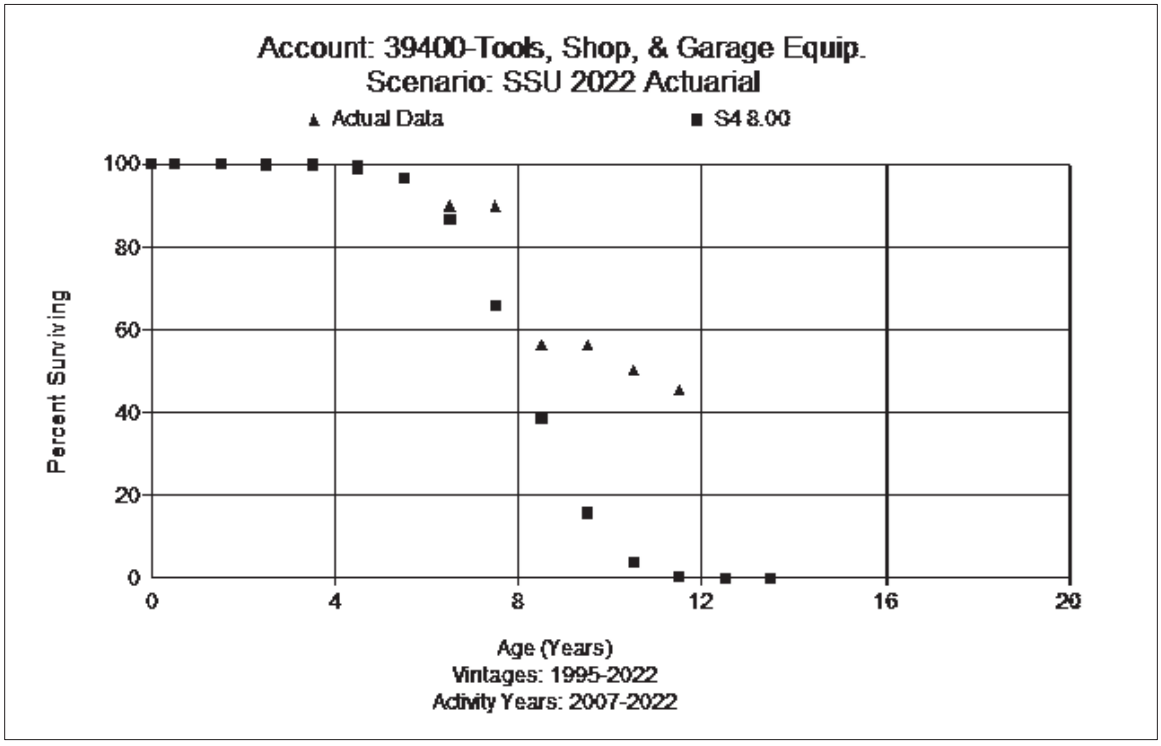
This account consists of all transportation equipment. The balance is $412 thousand. Depending on the type and mix of assets, this account can range from 5-15 years. The current average age of investment is 4.97 years. Only one retirement has been recorded in 2007. The Company leases most of its vehicles and surviving assets are golf carts, a trailer, and other miscellaneous equipment. Based on the surviving assets, this study recommends a 14 L5. A graph of the observed life table and the recommended life and curve are shown below.



No cost of removal has been recorded and none is expected. There has been no salvage recorded over the 2007-2022 historical experience. However, some salvage is expected at end of life for some of the assets. This study recommends a positive 10 percent net salvage rate.

Account 39400 – Tools, Shop & Garage Equipment

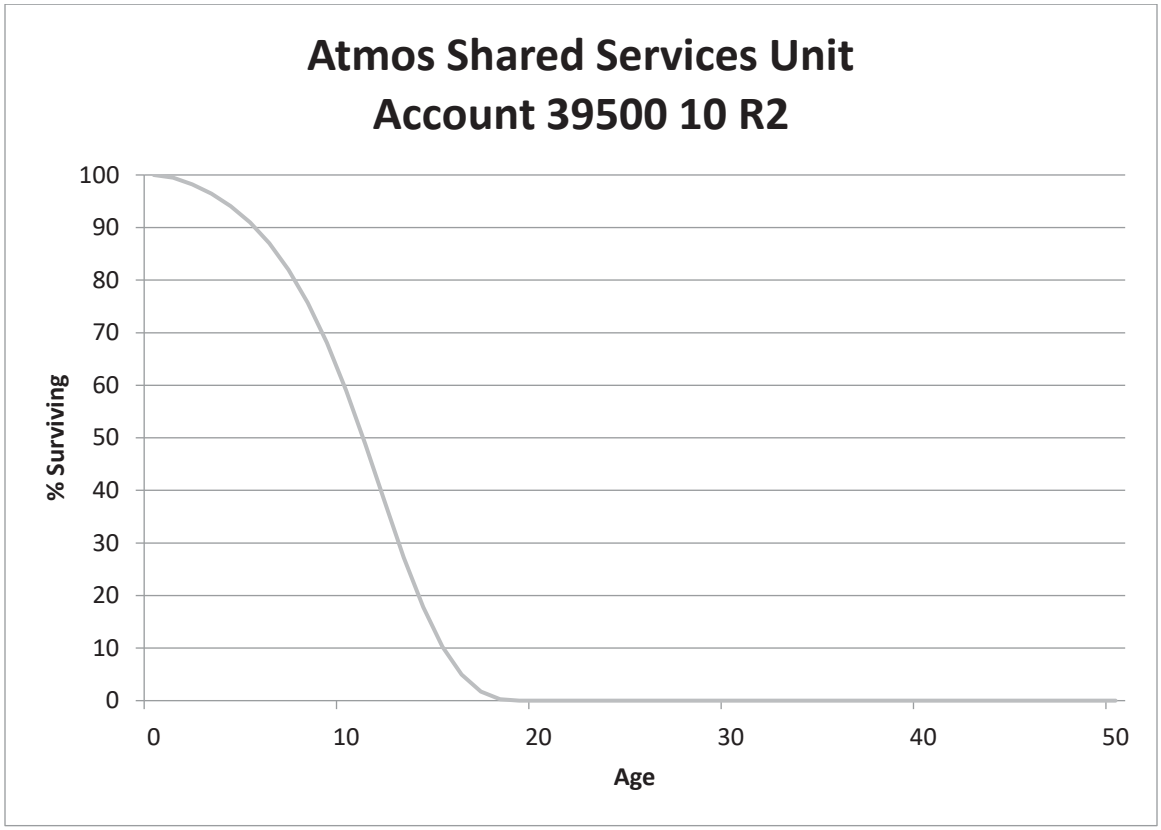
This account consists of various small tools and equipment used at the various locations. The balance is $717 thousand in this account. The average age of investment is 4.26 years. The average age of retirement is 7.81 years. Based on the analysis, and the type and use of the assets, this study recommends the 8 S4 life and dispersion pattern. A graph of the observed life table and the recommended life and curve are shown below.



No salvage or cost of removal has been recorded over the analysis 2007-2022 historical experience. There is no cost of removal expected and minimal or no salvage expected at the time of retirement. This study recommends a zero percent net salvage rate for this account.

Account 39500 – Laboratory Equipment

This account consists of laboratory equipment. It currently has no balance. Based on the type and use of the assets, a 10 year life is recommended with an R2 dispersion curve if future additions are recorded. A representative graph of the life of the account is shown in the curve below.



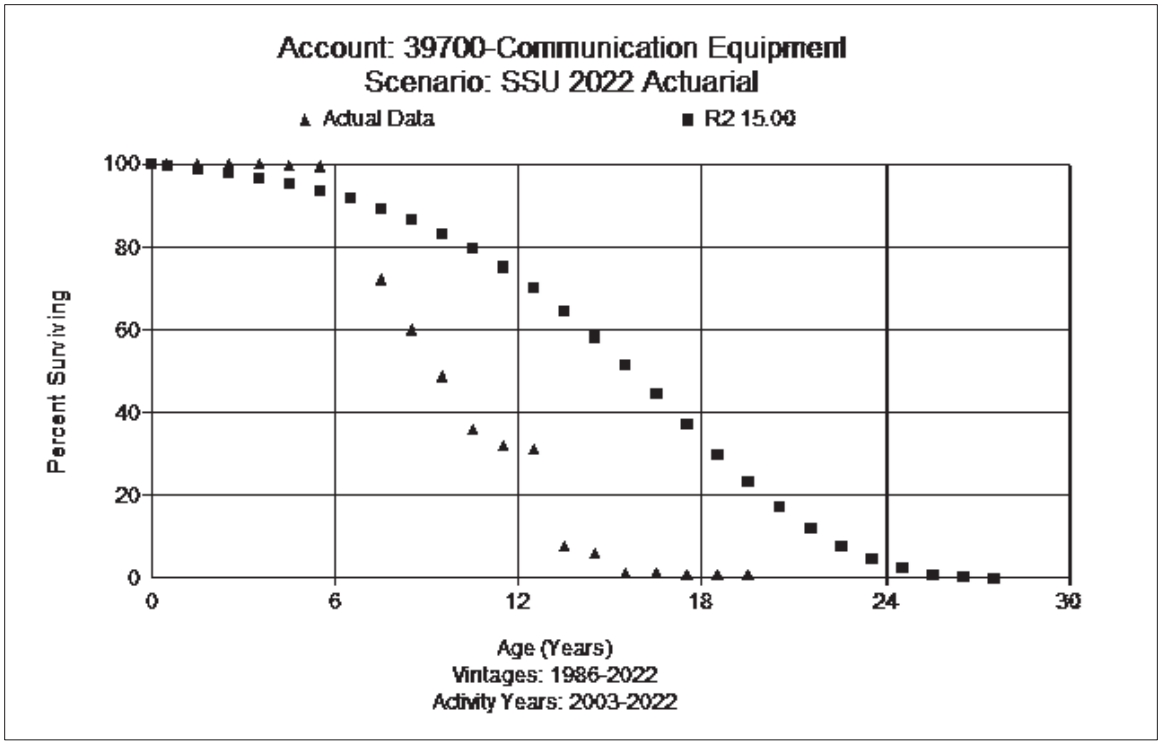
No salvage or cost of removal has been recorded and none is expected at time of retirement. This study recommends a zero percent net salvage rate for this account.

Account 39700 – Communications Equipment

The communications equipment account includes communication, computer hardware, telephone, and radio equipment used at the various locations. The balance is $2.8 million in this account.

Discussions with Company personnel indicated that around 2009, there was a contact center built in Amarillo, at which the communication assets are still in service. Many of the assets in this account are PBX related assets. The average age of the assets is around 11.46 years old. The Company indicated that there is no specific plan to replace significant portions of the communications infrastructure at this point.

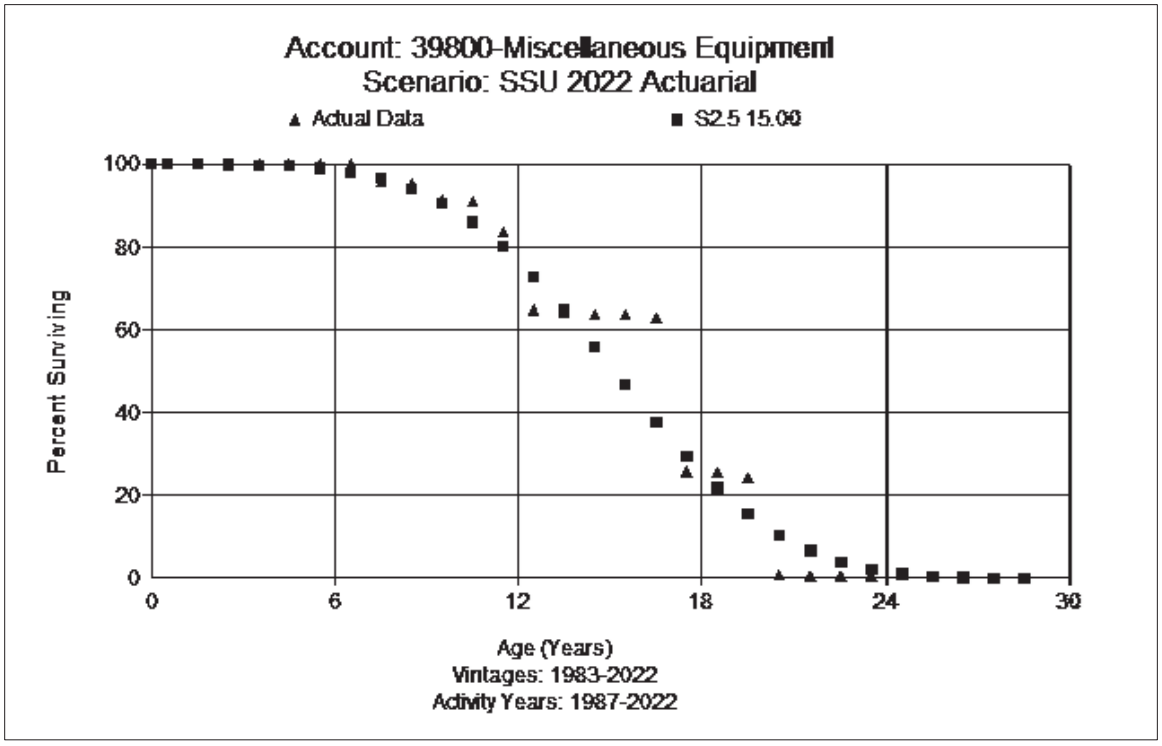
Based on the combined analysis, the best fits were indicating a life between 7-9 years, which is due to a large level of retirements in the last few years. The current average age of the assets is nearing 12 years. The shorter life indication in the analysis is not reflective of Company expectations for these assets. Based on the analysis, the type and mix of the assets, and Company plans and expectations, a 15 year life is more reasonable. This study recommends the 15 R2. A graph of the observed life table and the recommended life and curve are shown below.



Both salvage and cost of removal were recorded in 2004, but none since. No salvage is expected in the future at time of retirement. Little, if any, cost of removal is expected to be recorded for the assets. This study recommends a zero percent net salvage rate for this account.

Account 39800 - Miscellaneous Equipment

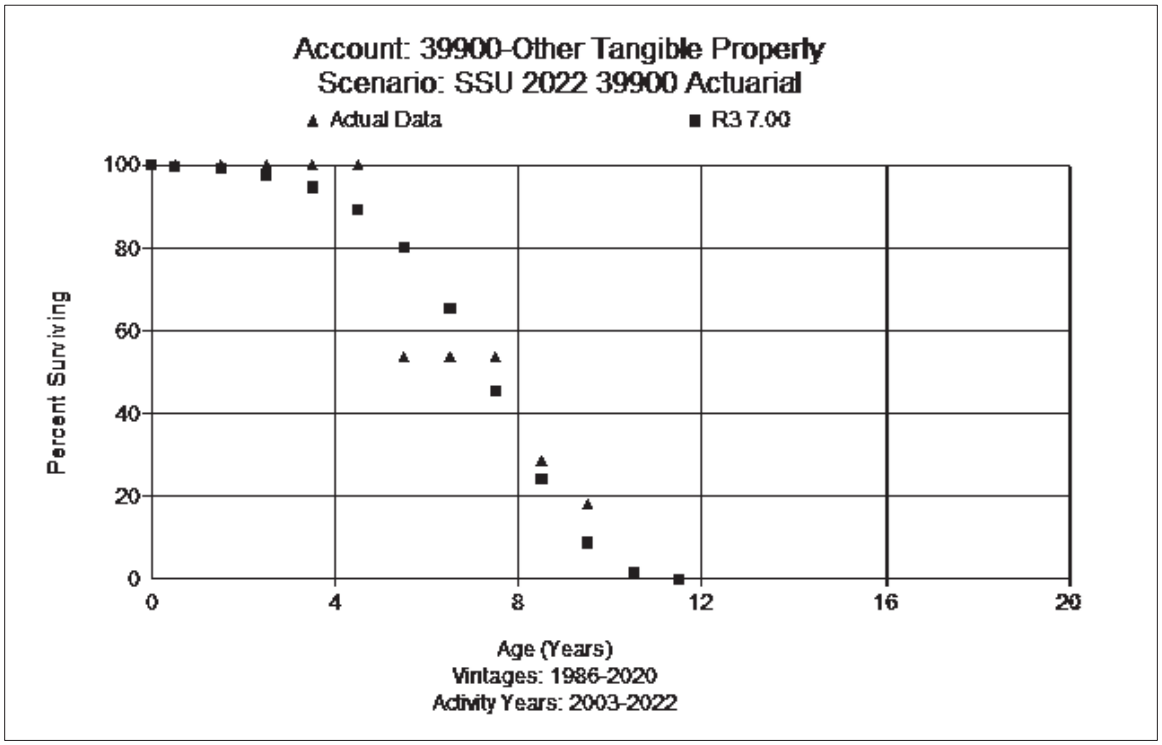
This account consists of various small office equipment items, such as kitchen appliances, televisions, and audio/video equipment that are not homogeneous with other plant accounts and are at the various locations. The balance is $738 thousand. The current average age of investment is 8.67 years. The analysis shows the majority of the fits to indicate a life around 15 years with a low dispersion pattern. The 15 S2.5 is a good fit across the bands fit and is the study recommendation. A graph of the observed life table and the recommended life and curve are shown below.



No salvage or cost of removal has been recorded since 1996 and none is expected at the time of retirement. This study recommends a zero percent net salvage rate for this account.

Account 39900 – Other Tangible Property

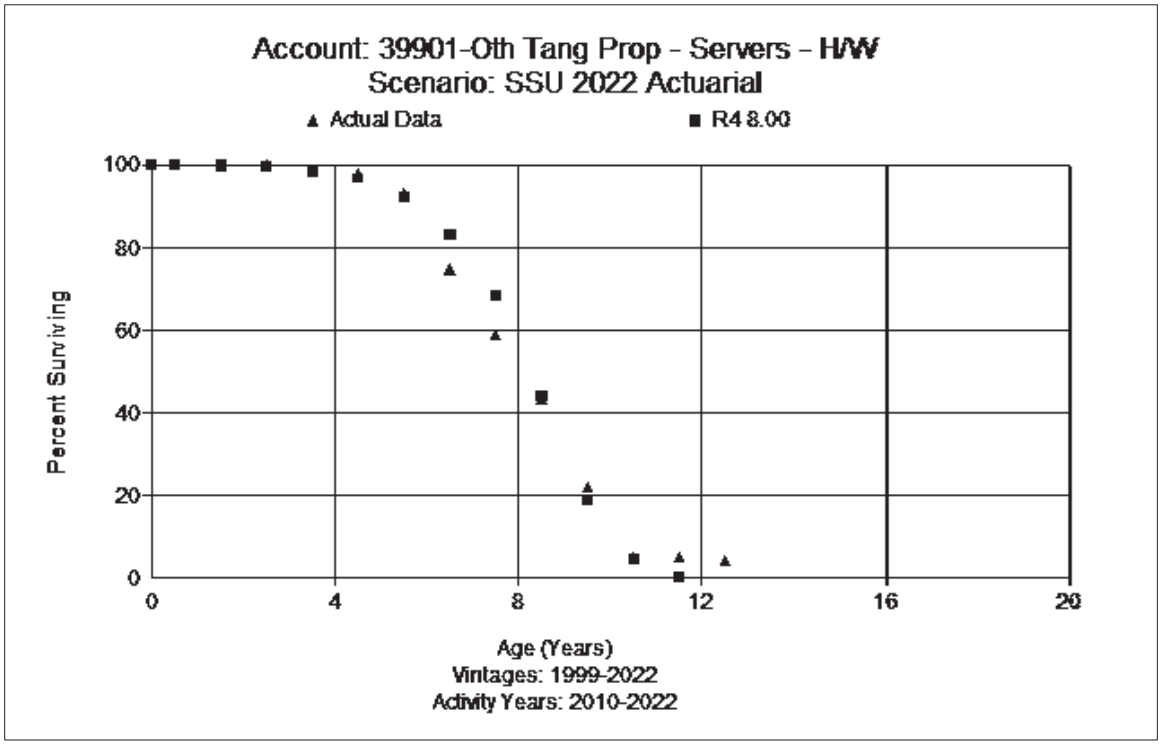
The other tangible property account holds miscellaneous equipment. The account balance is $299 thousand. The average age of the investment is 5.36 years. The average age of retirement is 7.01 years. The majority of the fits indicate a 7 year life, which is consistent with the expectations for this account. The study recommends the 7 R3 for this account. A graph of the observed life table and the recommended life and curve are shown below.



There has been no salvage or cost of removal recorded and none is expected in the future. This study recommends a zero percent net salvage rate for this account.

Account 39901 – Servers Hardware

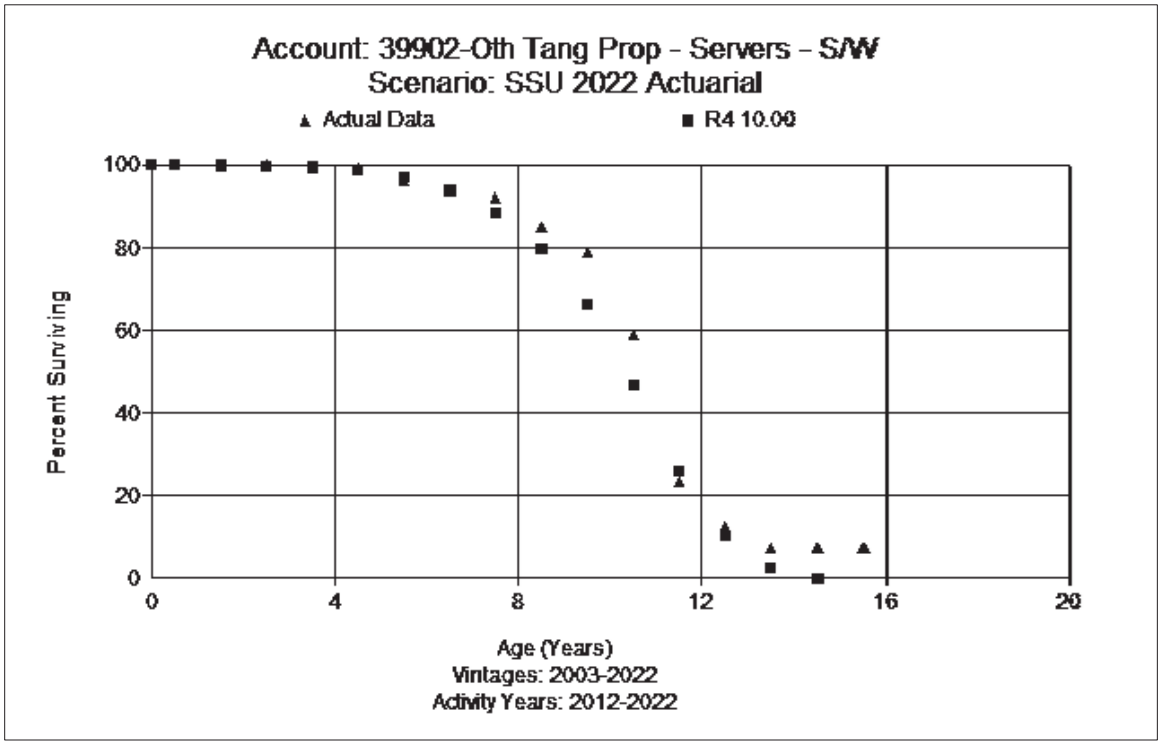
This account consists of assets such as server hardware and equipment used to serve the various locations. The balance is approximately $50.0 million. The current average age of the surviving balance is 4.39 years and the average age at retirement is 8.61 years. Discussions with Company personnel indicated that the initial manufacturer warranty is for 8 years, but they generally purchase an extended warranty, which can carry them a few years longer. The servers running the SAP system are planned for replacement around 8 years on average and the UCS servers are about to be replaced, also at 8 years. The current life analysis indicates a good fit with the 8 R4. Based on the analysis and Company input, this study recommends an 8 R4. A graph of the observed life table and the recommended life and curve is shown below.



Very little salvage or cost of removal has been recorded and no salvage or cost of removal is expected. A zero percent net salvage rate is recommended.

Account 39902 – Servers Software

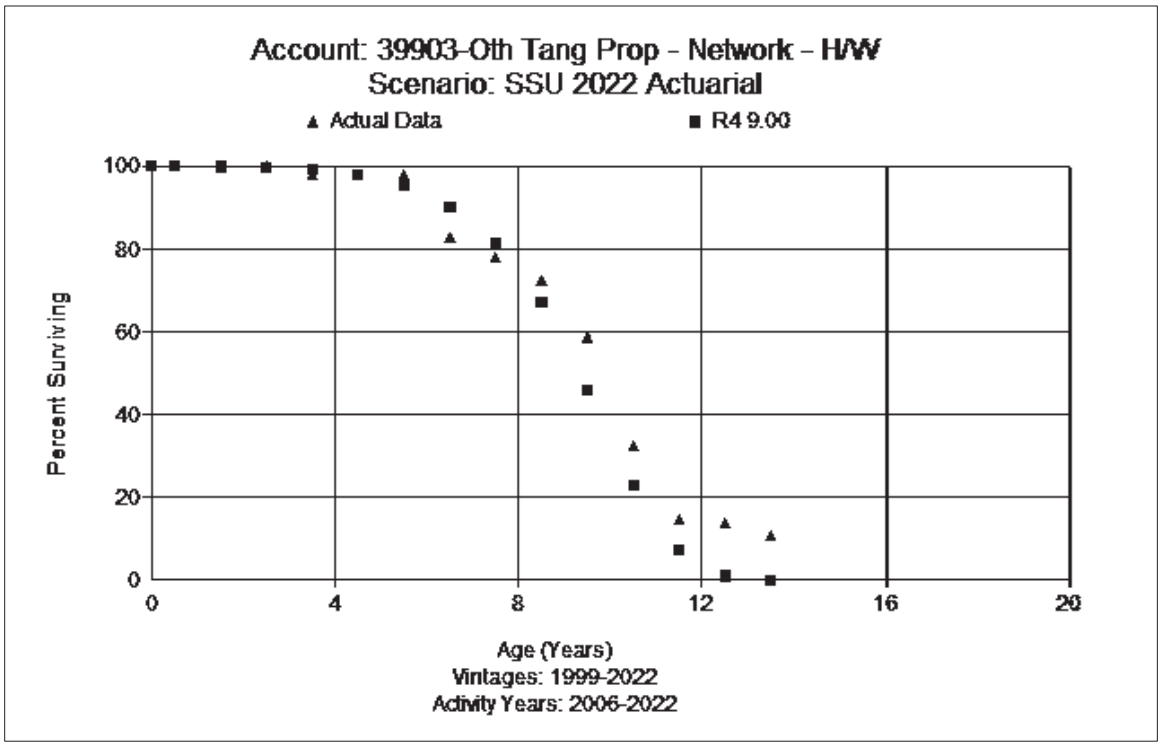
This account consists of assets such as Windows operating systems, Oracle, VMWare, Altiris, and other server software. The balance is $15.0 million. The average age of investment is 6.52 years. The average age of retirements is 11.56 years. Discussions with Company personnel indicated that virtualization disconnects the software from the hardware to some degree and can extend the life of the software as compared to the hardware. There are some perpetual licenses within this category. They now buy software with maintenance. The life analysis provides a consistent 10 year life indication. Even though technology is a factor, a life around 10 years makes sense operationally. This study recommends a 10 year life with the R4 dispersion pattern. A graph of the observed life table and the recommended life and curve are shown below.



No salvage or cost of removal has been recorded and none is expected in the future. A zero percent net salvage rate is recommended for this account.

Account 39903 – Network Hardware

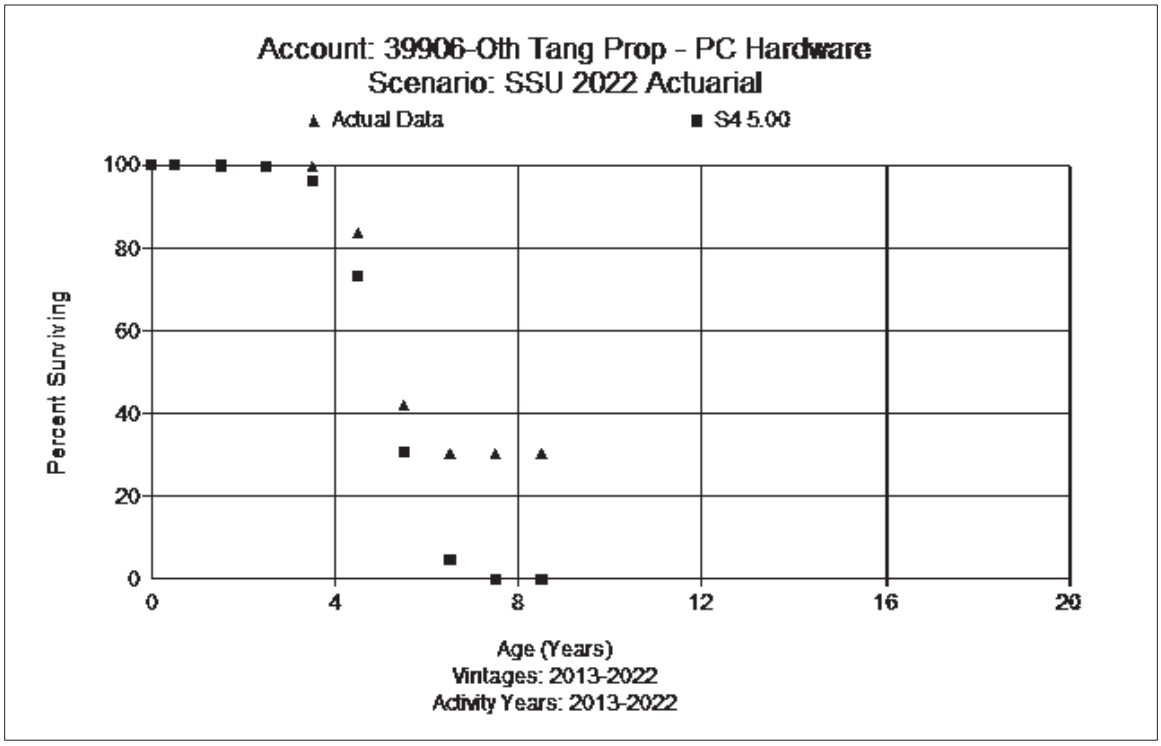
This account consists of assets related to networking activities such as routers, switches, and miscellaneous equipment. The balance is $5.3 million. The average age of retirements is 9.42 years, and the average age of investment is 4.91 years. Discussions with Company personnel indicated that the 2009 investment was for the data center, which has been replaced at around 10 years of age. Operationally the Company believes a 9 year life is reasonable and is the general expectation. The analysis shows a steep dispersion pattern and fits that are consistent with Company expectations of 9 years. This study recommends the 9 R4, which is slightly longer than server hardware. A graph of the observed life table and the recommended life and curve are shown below.



Cost of removal was recorded in 2012, but none since. No salvage or cost of removal is expected in the future. A zero percent net salvage rate is recommended for this account.

Account 39906 – PC Hardware

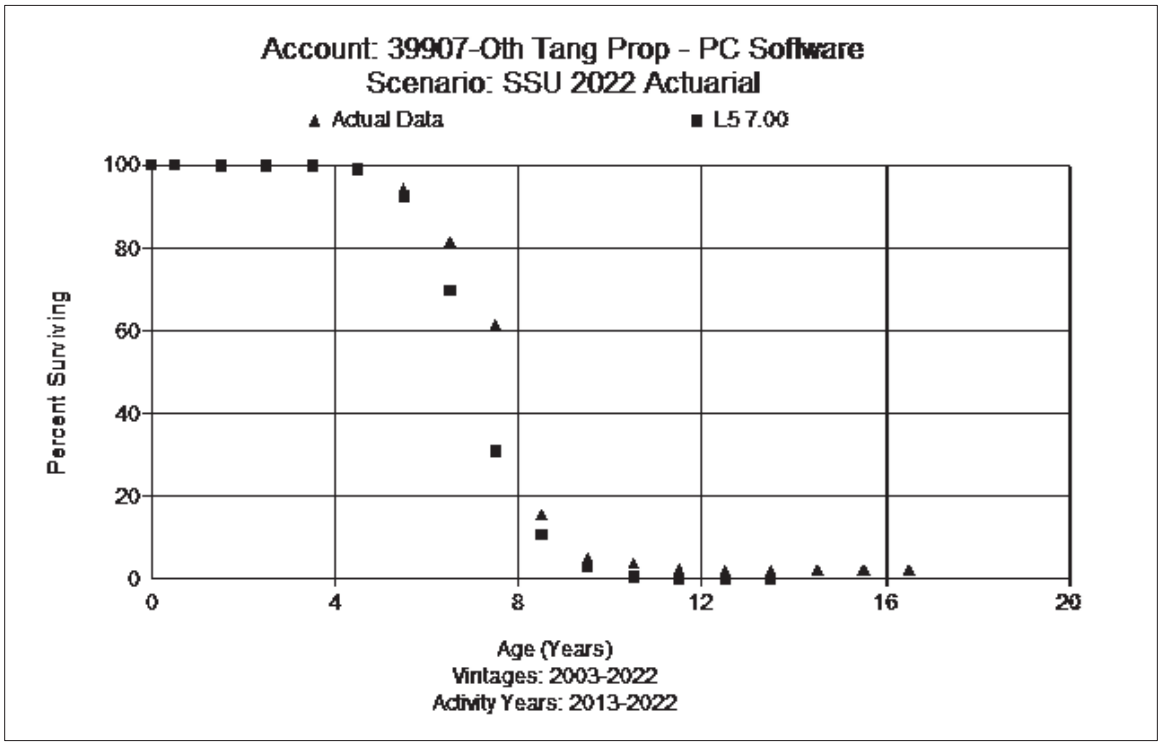
This account consists of costs for computer hardware, desktop and laptop computers, and peripherals. The balance is $5.0 million. The average age of investment is 3.53 years and average age of retirements is 7.11 years. Discussions with Company personnel indicated that there has been no material change in the replacement policies or practices. The refresh cycle is 4 years, which can see delays in retiring some computers due to prep for retiring or being kept as a spare or in inventory. Peripherals may have a longer life. The life indications in the actuarial analysis suggest a life between 5-7 years, with the 5 years as a more recent indication. Based on the life analysis and Company input, this study recommends the 5 S4. A graph of the observed life table and the recommended life and curve are shown below.



Some minimal salvage and very limited cost of removal have been recorded. This study recommends a zero percent net salvage rate for this account.

Account 39907 – PC Software

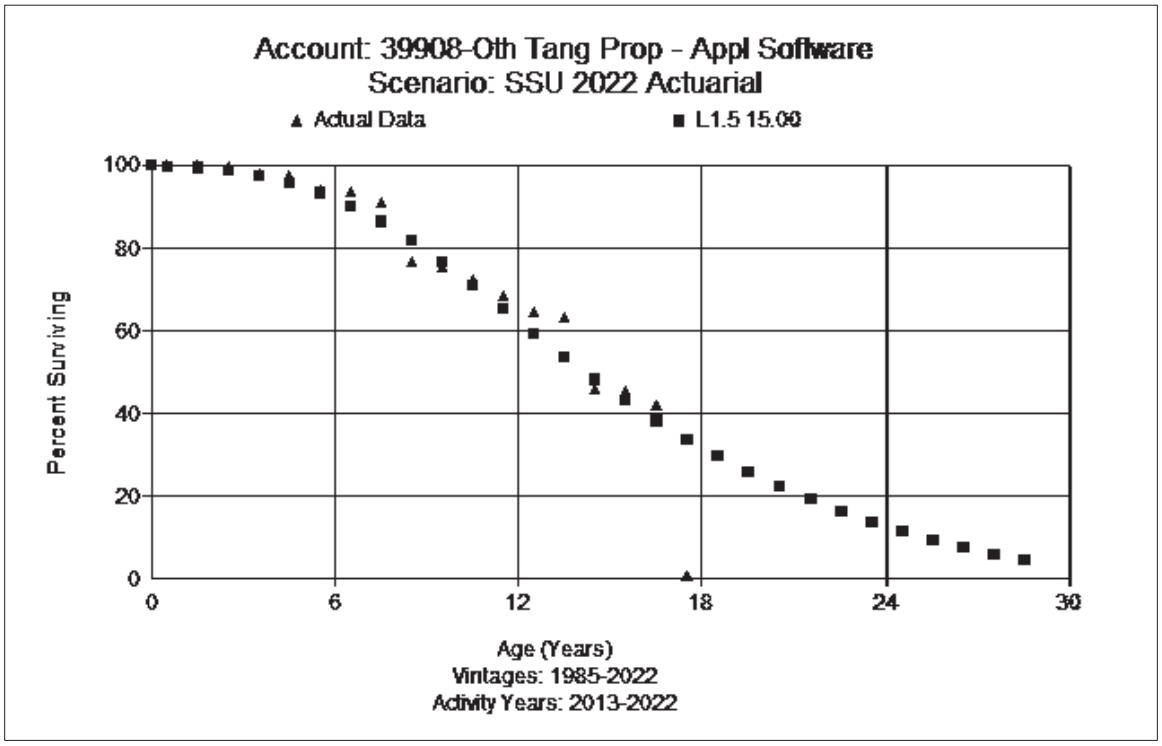
The PC software account consists of costs related to software assets and previously included operating system software. The balance is approximately $91 thousand after proforma transfers. The average age of investment is 7.46 years and average age of retirements is 9.12 years. Discussions with Company personnel indicated that one of the main pieces of PC software is Microsoft Office 365, which has gone to subscription. There are several assets that have been transferred to Account 39906 PC Hardware and 39908 Application Software as a proforma adjustment in the study. Recent historical additional and retirements may not reflect the true lifespan. TOAD for Oracle is over half of the account and is still in use. The analysis indicates a life between 7-9 years. Based on the analysis, Company input, type of assets, and judgment, this study recommends the 7 L5 dispersion at this time. A graph of the observed life table and the recommended life and curve are shown below.



No salvage or cost of removal has been recorded and none is expected. This study recommends a zero percent net salvage rate for this account.

Account 39908 – Application Software

The application software account consists of costs related to large software assets including billing system software, electronic mapping and training software applications, Oracle upgrade, Banner, Data Mart System, PowerPlant System, Advantage System application, and the Waco Call Center IT build. The balance is $242.3 million. The average age of the surviving assets is 8.40 years and average age of retirements is 19.14 years. Discussions with Company personnel indicated that their expectation for the major software platforms is that they can last 15 years or more. They will upgrade but not retire the original asset unless they move to a different platform. The analysis supports a life between 13 to 15 years. Based on all the information and judgment, this study recommends the 15 L1.5 dispersion for this account. A graph of the observed life table and the recommended life and curve are shown below.



No salvage has been recorded and none is expected at time of retirement. Some cost of removal was recorded in 2013 but none is expected in the future. This study recommends a zero percent net salvage rate for this account.

APPENDIX A - Annual Accrual and Rate

Appendix A

Atmos Energy - Shared Services
At September 30, 2022
Depreciation Study Annual Depreciation Rates and Accruals

Account	Description	Plant Balance 09/30/2022	Annual Accrual Rate	Annual Accrual Amount
(a)	(b)	(c)	(d)	(e)
39000	Structures & Improvements	$ 46,093,940	2.38%	$ 1,097,036
39009	Improvements - Leased	12,884,577	4.43%	570,787
39100	Office Furniture & Equipment	9,760,344	6.36%	620,758
39200	Transportation Equipment	411,688	6.59%	27,130
39400	Tools Shop And Garage	717,219	12.44%	89,222
39700	Communication Equipment	2,842,154	6.34%	180,193
39800	Miscellaneous Equipment	738,358	7.00%	51,685
39900	Other Tangible Equipment	299,459	14.24%	42,643
39901	Servers-Hardware	49,962,908	12.66%	6,325,304
39902	Servers-Software	15,012,653	10.10%	1,516,278
39903	Network Hardware	5,339,322	11.28%	602,276
39906	PC Hardware	5,015,652	19.93%	999,619
39907	PC Software	90,525	11.66%	10,555
39908	Application Software	242,323,348	6.93%	16,793,008
	Total Depreciable Plant	$ 391,492,146	7.39%	$ 28,926,494

APPENDIX B - Calculation of Accrual and Rates

Appendix B

Atmos Energy - Shared Services
At September 30, 2022
Calculation of Depreciation Annual Accrual and Rate
With Reserve Reallocation

Account	Description	Plant Balance	Allocated Book Reserve	Net Salvage %	Net Salvage Amount	Unaccrued Balance	Composite Remaining Life	Annual Accrual Amount	Annual Accrual Rate
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
39000	Structures & Improvements	$ 46,093,940	$ 10,012,300	0%	$ -	$ 36,081,640	32.83	$ 1,098,991	2.38%
39009	Improvements - Leased	12,884,577	9,199,732	0%	-	3,684,845	6.46	570,785	4.43%
39100	Office Furniture & Equipment	9,760,344	5,965,482	0%	-	3,794,862	6.11	620,737	6.36%
39200	Transportation Equipment	411,688	125,431	10%	41,169	245,088	9.03	27,140	6.59%
39400	Tools Shop And Garage	717,219	477,203	0%	-	240,015	2.69	89,211	12.44%
39700	Communication Equipment	2,842,154	1,827,582	0%	-	1,014,572	5.63	180,122	6.34%
39800	Miscellaneous Equipment	738,358	408,363	0%	-	329,995	6.39	51,674	7.00%
39900	Other Tangible Equipment	299,459	205,675	0%	-	93,784	2.20	42,628	14.24%
39901	Servers-Hardware	49,962,908	24,465,692	0%	-	25,497,216	4.03	6,323,496	12.66%
39902	Servers-Software	15,012,653	8,763,896	0%	-	6,248,757	4.12	1,515,591	10.10%
39903	Network Hardware	5,339,322	2,543,324	0%	-	2,795,998	4.64	602,187	11.28%
39906	PC Hardware	5,015,652	3,084,461	0%	-	1,931,191	1.93	999,665	19.93%
39907	PC Software	90,525	80,092	0%	-	10,433	0.99	10,551	11.66%
39908	Application Software	242,323,348	121,159,499	0%	-	121,163,849	7.22	16,788,920	6.93%
	Total Depreciable Plant	**$ 391,492,146**	**$ 188,318,732**		**$ 41,169**	**$ 203,132,245**		**$ 28,921,699**	**7.39%**

APPENDIX C - Parameters

Appendix C

Atmos Energy - Shared Services Unit
Proposed Depreciation Parameters
Depreciation Study as of September 30, 2022

Division 002 - SSU General Office and Division 12 - SSU Customer Support

		Proposed 2022				
Account	Description	ASL	Curve	Gross Salvage	Cost of Removal	Net Salvage
39000	Structure & Improvements	50	R2	0%	0%	0%
39009	Improvements - Leased	20	R2	0%	0%	0%
39100	Office Furniture & Equipment	16	R4	0%	0%	0%
39200	Transportation Equipment	14	L5	10%	0%	10%
39400	Tools, Shop, & Garage Equipment	8	S4	0%	0%	0%
39500	Laboratory Equipment	10	R2	0%	0%	0%
39700	Communication Equipment	15	R2	0%	0%	0%
39800	Miscellaneous Equipment	15	S2.5	0%	0%	0%
39900	Other Tangible Equipment	7	R3	0%	0%	0%
39901	Servers-Hardware	8	R4	0%	0%	0%
39902	Servers-Software	10	R4	0%	0%	0%
39903	Network Hardware	9	R4	0%	0%	0%
39906	PC Hardware	5	S4	0%	0%	0%
39907	PC Software	7	L5	0%	0%	0%
39908	Application Software	15	L1.5	0%	0%	0%

APPENDIX D - Net Salvage Analysis

ATMOS ENERGY - SHARED SERVICES UNIT
Depreciation Study as of September 30, 2022
Net Salvage Analysis

Account and Description		Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
39000-Structures & Improvements		2007	0.00	-	-	0	NA									
	39000	2008	0.00	-	-	0	NA	NA								
	39000	2009	0.00	-	-	0	NA	NA	NA							
	39000	2010	0.00	-	-	0	NA	NA	NA	NA						
	39000	2011	0.00	-	-	0	NA	NA	NA	NA	NA					
	39000	2012	0.00	-	-	0	NA	NA	NA	NA	NA	NA				
	39000	2013	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA			
	39000	2014	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
	39000	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
	39000	2016	32,329.68	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39000	2017	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39000	2018	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39000	2019	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39000	2020	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39000	2021	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
	39000	2022	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
39000-Structures & Improvements		2007	0.00	-	-	0	NA									
	39005	2008	0.00	-	-	0	NA	NA								
	39005	2009	0.00	-	-	0	NA	NA	NA							
	39005	2010	0.00	-	-	0	NA	NA	NA	NA						
	39005	2011	0.00	-	-	0	NA	NA	NA	NA	NA					
	39005	2012	0.00	-	-	0	NA	NA	NA	NA	NA	NA				
	39005	2013	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA			
	39005	2014	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
	39005	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
	39005	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39005	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39005	2018	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39005	2019	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39005	2020	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39005	2021	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39005	2022	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39009-Improv. to Leased Premises		2000	270,911.00	-	-	0	0.0%									
	39009	2001	0.00	-	-	0	NA	0.0%								
	39009	2002	0.00	-	-	0	NA	NA	0.0%							
	39009	2003	0.00	-	-	0	NA	NA	NA	0.0%						
	39009	2004	0.00	-	-	0	NA	NA	NA	NA	0.0%					
	39009	2005	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%				
	39009	2006	178,757.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%			

ATMOS ENERGY - SHARED SERVICES UNIT
Depreciation Study as of September 30, 2022
Net Salvage Analysis

Account and Description		Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
	39009	2007	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%		
	39009	2008	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	
	39009	2009	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2010	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2011	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2012	35,416.90	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2013	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2014	126,214.30	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2015	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2016	1,473,692.48	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2017	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2018	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2019	437,955.87	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2020	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2021	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39009	2022	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
39100-Office Furniture & Equipment		1993	83,992.00	200	-	200	0.2%									
	39100	1994	7,848.00	-	-	0	0.0%	0.2%								
	39100	1995	852.00	-	-	0	0.0%	0.0%	0.2%							
	39100	1996	92,361.00	-	-	0	0.0%	0.0%	0.0%	0.1%						
	39100	1997	0.00	-	(5,108)	5,108	NA	5.5%	5.5%	5.1%	2.9%					
	39100	1998	6,852.00	-	-	0	0.0%	74.5%	5.1%	5.1%	4.7%	2.77%				
	39100	1999	0.00	-	-	0	NA	0.0%	74.5%	5.1%	5.1%	4.73%	2.77%			
	39100	2000	0.00	-	-	0	NA	NA	0.0%	74.5%	5.1%	5.10%	4.73%	2.77%		
	39100	2001	0.00	-	-	0	NA	NA	NA	0.0%	74.5%	5.15%	5.10%	4.73%	2.77%	
	39100	2002	0.00	-	-	0	NA	NA	NA	NA	0.0%	74.55%	5.15%	5.10%	4.73%	2.77%
	39100	2003	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	74.55%	5.15%	5.10%	4.73%
	39100	2004	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	74.55%	5.15%	5.10%
	39100	2005	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%	74.55%	5.15%
	39100	2006	1,420,965.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.36%
	39100	2007	75,094.25	0	0	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2008	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2009	225,893.25	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2010	95,413.03	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2011	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2012	788,807.96	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2013	1,602,991.05	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2014	1,162.59	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2015	358,929.73	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2016	1,020,914.56	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2017	4,530,386.30	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%

ATMOS ENERGY - SHARED SERVICES UNIT
Depreciation Study as of September 30, 2022
Net Salvage Analysis

Account and Description		Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
	39100	2018	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2019	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2020	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2021	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39100	2022	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
39100-Office Furniture & Equipment		2007	0.00	-	-	0	NA									
	39101	2008	0.00	-	-	0	NA	NA								
	39101	2009	0.00	-	-	0	NA	NA	NA							
	39101	2010	0.00	-	-	0	NA	NA	NA	NA						
	39101	2011	0.00	-	-	0	NA	NA	NA	NA	NA					
	39101	2012	0.00	-	-	0	NA	NA	NA	NA	NA	NA				
	39101	2013	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA			
	39101	2014	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
	39101	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
	39101	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39101	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39101	2018	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39101	2019	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39101	2020	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39101	2021	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39101	2022	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39100-Office Furniture & Equipment		2007	0.00	-	-	0	NA									
	39102	2008	0.00	-	-	0	NA	NA								
	39102	2009	0.00	-	-	0	NA	NA	NA							
	39102	2010	25,380.12	-	-	0	0.0%	0.0%	0.0%	0.0%						
	39102	2011	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%					
	39102	2012	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%				
	39102	2013	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%			
	39102	2014	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%		
	39102	2015	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
	39102	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
	39102	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
	39102	2018	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
	39102	2019	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
	39102	2020	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39102	2021	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39102	2022	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

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39100-Office Furniture & Equipment		2007	387,811.54	-	-	0	0.0%									
	39103	2008	0.00	-	-	0	NA	0.0%								
	39103	2009	0.00	-	-	0	NA	NA	0.0%							
	39103	2010	48,493.05	-	-	0	0.0%	0.0%	0.0%	0.0%						
	39103	2011	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%					
	39103	2012	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%				
	39103	2013	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%			
	39103	2014	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%		
	39103	2015	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
	39103	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
	39103	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
	39103	2018	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
	39103	2019	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
	39103	2020	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39103	2021	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39103	2022	47,938.52	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
39104-G Office Furniture & Equipment		2010	0.00	-	-	0	NA									
	39104	2011	0.00	-	-	0	NA	NA								
	39104	2012	0.00	-	-	0	NA	NA	NA							
	39104	2013	0.00	-	-	0	NA	NA	NA	NA						
	39104	2014	0.00	-	-	0	NA	NA	NA	NA	NA					
	39104	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA				
	39104	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA			
	39104	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
	39104	2018	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
	39104	2019	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39104	2020	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39104	2021	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39104	2022	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39200-Transportation Equipment		2007	18,885.47	-	-	0	0.0%									
	39200	2008	0.00	-	-	0	NA	0.0%								
	39200	2009	0.00	-	-	0	NA	NA	0.0%							
	39200	2010	0.00	-	-	0	NA	NA	NA	0.0%						
	39200	2011	0.00	-	-	0	NA	NA	NA	NA	0.0%					
	39200	2012	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%				
	39200	2013	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%			
	39200	2014	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%		
	39200	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	
	39200	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%

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	39200	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39200	2018	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39200	2019	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39200	2020	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39200	2021	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39200	2022	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39300-Stores Equipment		2007	0.00	-	-	0	NA									
	39300	2008	0.00	-	-	0	NA	NA								
	39300	2009	0.00	-	-	0	NA	NA	NA							
	39300	2010	0.00	-	-	0	NA	NA	NA	NA						
	39300	2011	0.00	-	-	0	NA	NA	NA	NA	NA					
	39300	2012	0.00	-	-	0	NA	NA	NA	NA	NA	NA				
	39300	2013	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA			
	39300	2014	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
	39300	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
	39300	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39300	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39300	2018	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39300	2019	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39300	2020	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39300	2021	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39300	2022	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39400-Tools, Shop, & Garage Equip.		2007	7,682.72	-	-	0	0.0%									
	39400	2008	0.00	-	-	0	NA	0.0%								
	39400	2009	0.00	-	-	0	NA	NA	0.0%							
	39400	2010	0.00	-	-	0	NA	NA	NA	0.0%						
	39400	2011	0.00	-	-	0	NA	NA	NA	NA	0.0%					
	39400	2012	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%				
	39400	2013	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%			
	39400	2014	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%		
	39400	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	
	39400	2016	27.50	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39400	2017	123,339.96	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39400	2018	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39400	2019	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39400	2020	20,120.34	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39400	2021	8,616.01	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39400	2022	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%

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39500-Laboratory Equipment		2007	0.00	-	-	0	NA									
	39500	2008	0.00	-	-	0	NA	NA								
	39500	2009	0.00	-	-	0	NA	NA	NA							
	39500	2010	0.00	-	-	0	NA	NA	NA	NA						
	39500	2011	0.00	-	-	0	NA	NA	NA	NA	NA					
	39500	2012	0.00	-	-	0	NA	NA	NA	NA	NA	NA				
	39500	2013	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA			
	39500	2014	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
	39500	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
	39500	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39500	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39500	2018	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39500	2019	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39500	2020	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39500	2021	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39500	2022	23,632.07	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
39700-Communication Equipment		1993	8,091.00	-	-	0	0.0%									
	39700	1994	0.00	-	-	0	NA	0.0%								
	39700	1995	0.00	-	-	0	NA	NA	0.0%							
	39700	1996	0.00	-	-	0	NA	NA	NA	0.0%						
	39700	1997	0.00	-	-	0	NA	NA	NA	NA	0.0%					
	39700	1998	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%				
	39700	1999	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%			
	39700	2000	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%		
	39700	2001	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	
	39700	2002	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
	39700	2003	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39700	2004	34,015.00	26,609	3,107	23,502	69.1%	69.1%	69.1%	69.1%	69.1%	69.09%	69.09%	69.09%	69.09%	69.09%
	39700	2005	0.00	-	-	0	NA	69.1%	69.1%	69.1%	69.1%	69.09%	69.09%	69.09%	69.09%	69.09%
	39700	2006	792,568.00	-	-	0	0.0%	0.0%	2.8%	2.8%	2.8%	2.84%	2.84%	2.84%	2.84%	2.84%
	39700	2007	0.00	-	-	0	NA	0.0%	0.0%	2.8%	2.8%	2.84%	2.84%	2.84%	2.84%	2.84%
	39700	2008	16,529.96	-	-	0	0.0%	0.0%	0.0%	0.0%	2.8%	2.79%	2.79%	2.79%	2.79%	2.79%
	39700	2009	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	2.79%	2.79%	2.79%	2.79%	2.79%
	39700	2010	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	2.79%	2.79%	2.79%	2.79%
	39700	2011	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	2.79%	2.79%	2.79%
	39700	2012	24,247,439.73	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.09%	0.09%
	39700	2013	118,855.67	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.09%
	39700	2014	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39700	2015	34,412.20	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39700	2016	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%

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	39700	2017	1,440,195.73	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39700	2018	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39700	2019	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39700	2020	664,148.96	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39700	2021	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39700	2022	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
39800-Miscellaneous Equipment		1996	149,090.00	9,000	-	9,000	6.0%									
	39800	1997	0.00	-	-	0	NA	6.0%								
	39800	1998	0.00	-	-	0	NA	NA	6.0%							
	39800	1999	0.00	-	-	0	NA	NA	NA	6.0%						
	39800	2000	0.00	-	-	0	NA	NA	NA	NA	6.0%					
	39800	2001	0.00	-	-	0	NA	NA	NA	NA	NA	6.04%				
	39800	2002	0.00	-	-	0	NA	NA	NA	NA	NA	NA	6.04%			
	39800	2003	56,637.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	4.37%		
	39800	2004	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	4.37%	
	39800	2005	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	4.37%
	39800	2006	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2007	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2008	419,274.36	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2009	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2010	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2011	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2012	25,971.27	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2013	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2014	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2015	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2016	190,238.12	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2017	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2018	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2019	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2020	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2021	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
	39800	2022	36,386.96	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
39800-Miscellaneous Equipment		2007	0.00	-	-	0	NA									
	39809	2008	0.00	-	-	0	NA	NA								
	39809	2009	0.00	-	-	0	NA	NA	NA							
	39809	2010	0.00	-	-	0	NA	NA	NA	NA						
	39809	2011	0.00	-	-	0	NA	NA	NA	NA	NA					
	39809	2012	0.00	-	-	0	NA	NA	NA	NA	NA	NA				

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	39809	2013	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA			
	39809	2014	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
	39809	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
	39809	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39809	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39809	2018	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39809	2019	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39809	2020	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39809	2021	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39809	2022	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39900-Other Tangible Property		1994	219,471.00	-	-	0	0.0%									
39910-CKV-Other Tangible Property		1995	0.00	-	-	0	NA	0.0%								
39918-CKV-Other Tangible Property		1996	0.00	-	-	0	NA	NA	0.0%							
39924-Other Tangible Property General		1997	0.00	-	-	0	NA	NA	NA	0.0%						
	39900	1998	0.00	-	-	0	NA	NA	NA	NA	0.0%					
	39900	1999	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%				
	39900	2000	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%			
	39900	2001	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%		
	39900	2002	8,143.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	
	39900	2003	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2004	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2005	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2006	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2007	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2008	224,866.15	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2009	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2010	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2011	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2011	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2012	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2013	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
	39900	2014	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
	39900	2015	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
	39900	2016	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
	39900	2017	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	39900	2018	629,166.46	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2019	162,267.97	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2020	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2021	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39900	2022	1,651.55	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%

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39921-OthTang Prop-Servers-H/W-AEAM																
39901-Oth Tang Prop - Servers - H/W		2007	0.00	-	-	0	NA									
	39901	2008	0.00	-	-	0	NA	NA								
	39901	2009	0.00	-	-	0	NA	NA	NA							
	39901	2010	0.00	-	-	0	NA	NA	NA	NA						
	39901	2011	0.00	-	-	0	NA	NA	NA	NA	NA					
	39901	2012	10,873,204.70	-	(129)	129	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%				
	39901	2013	3,585,983.60	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%			
	39901	2014	452,050.30	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%		
	39901	2015	8,526,616.39	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	
	39901	2016	458,170.94	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39901	2017	1,469,953.03	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39901	2018	18,837,035.72	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39901	2019	106,175.33	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39901	2020	7,303,174.25	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39901	2021	67,314.03	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39901	2022	1,478,152.02	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
39922-OthTang Prop-Servers-S/W-AEAM																
39902-Oth Tang Prop - Servers - S/W		2007	0.00	-	-	0	NA									
	39902	2008	0.00	-	-	0	NA	NA								
	39902	2009	0.00	-	-	0	NA	NA	NA							
	39902	2010	0.00	-	-	0	NA	NA	NA	NA						
	39902	2011	0.00	-	-	0	NA	NA	NA	NA	NA					
	39902	2012	6,624,795.54	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%				
	39902	2013	1,467,367.65	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%			
	39902	2014	497,701.44	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%		
	39902	2015	226,110.26	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	
	39902	2016	163,043.25	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39902	2017	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39902	2018	991,615.69	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39902	2019	10,688,603.52	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39902	2020	675,486.81	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39902	2021	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39902	2022	1,110,279.74	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%

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39923-OthTang Prop-Network-H/W-AEAM																
39903-Oth Tang Prop - Network - H/W		2006	11,472.00	-	-	0	0.0%									
	39903	2007	0.00	-	-	0	NA	0.0%								
	39903	2008	0.00	-	-	0	NA	NA	0.0%							
	39903	2009	0.00	-	-	0	NA	NA	NA	0.0%						
	39903	2010	0.00	-	-	0	NA	NA	NA	NA	0.0%					
	39903	2011	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%				
	39903	2012	886,043.63	-	1,278	(1,278)	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.14%	-0.14%			
	39903	2013	110,058.63	-	-	0	0.0%	-0.1%	-0.1%	-0.1%	-0.1%	-0.13%	-0.13%	-0.13%		
	39903	2014	237,149.12	-	-	0	0.0%	0.0%	-0.1%	-0.1%	-0.1%	-0.10%	-0.10%	-0.10%	-0.10%	
	39903	2015	1,348,505.07	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%
	39903	2016	33,700.31	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%
	39903	2017	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%
	39903	2018	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	-0.05%	-0.05%	-0.05%	-0.05%
	39903	2019	154,713.05	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	-0.05%	-0.05%	-0.05%
	39903	2020	2,698,241.83	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	-0.02%	-0.02%
	39903	2021	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	-0.02%
	39903	2022	51,006.75	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
39916-CKV-Oth Tang Prop-PC Hardware																
39906-Oth Tang Prop - PC Hardware		1994	97,832.00	-	-	0	0.0%									
	39906	1995	0.00	-	-	0	NA	0.0%								
	39906	1996	116,913.00	-	-	0	0.0%	0.0%	0.0%							
	39906	1997	0.00	-	-	0	NA	0.0%	0.0%	0.0%						
	39906	1998	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%					
	39906	1999	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%				
	39906	2000	2,832.00	3,000	45	2,955	104.3%	104.3%	104.3%	104.3%	2.5%	2.47%	1.36%			
	39906	2001	0.00	-	-	0	NA	104.3%	104.3%	104.3%	104.3%	2.47%	2.47%	1.36%		
	39906	2002	6,189,732.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.05%	0.05%	0.05%	0.05%	
	39906	2003	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.05%	0.05%	0.05%	0.05%	0.05%
	39906	2004	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.05%	0.05%	0.05%	0.05%	0.05%
	39906	2005	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.05%	0.05%	0.05%	0.05%	0.05%
	39906	2006	2,632,955.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.03%	0.03%	0.03%	0.03%
	39906	2007	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.03%	0.03%	0.03%
	39906	2008	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.03%	0.03%
	39906	2009	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.03%
	39906	2010	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39906	2011	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
	39906	2011	2,825,516.07	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39906	2012	4,649,967.16	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%

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	39906	2013	217,743.76	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39906	2014	162,561.94	250	-	250	0.2%	0.1%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39906	2015	1,660,308.12	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39906	2016	696,097.17	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39906	2017	18,020.39	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39906	2018	1,537,084.51	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.01%	0.00%	0.00%	0.00%	0.00%
	39906	2019	148,508.48	3,272	-	3,272	2.2%	0.2%	0.2%	0.1%	0.1%	0.08%	0.08%	0.04%	0.03%	0.03%
	39906	2020	963,667.27	-	-	0	0.0%	0.3%	0.1%	0.1%	0.1%	0.07%	0.07%	0.07%	0.04%	0.03%
	39906	2021	0.00	-	-	0	NA	0.0%	0.3%	0.1%	0.1%	0.10%	0.07%	0.07%	0.07%	0.04%
	39906	2022	0.00	-	-	0	NA	NA	0.0%	0.3%	0.1%	0.12%	0.10%	0.07%	0.07%	0.07%
39917-CKV-Oth Tang Prop-PC Software																
39907-Oth Tang Prop - PC Software		1994	38,759.00	-	-	0	0.0%									
	39907	1995	0.00	-	-	0	NA	0.0%								
	39907	1996	0.00	-	-	0	NA	NA	0.0%							
	39907	1997	0.00	-	-	0	NA	NA	NA	0.0%						
	39907	1998	0.00	-	-	0	NA	NA	NA	NA	0.0%					
	39907	1999	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%				
	39907	2000	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%			
	39907	2001	0.00	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%		
	39907	2002	861,539.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	
	39907	2003	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2004	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2005	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2006	16,495.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2007	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2008	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2009	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2010	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2011	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2011	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
	39907	2012	2,918,743.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2013	366,151.43	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2014	599,561.35	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2015	864,237.58	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2016	143,270.73	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2017	132,181.39	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2018	192,229.23	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2019	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2020	325,856.38	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2021	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39907	2022	3,261.74	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%

ATMOS ENERGY - SHARED SERVICES UNIT
Depreciation Study as of September 30, 2022
Net Salvage Analysis

Account and Description		Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
39928-Oth Tang Prop-Appl SW-AEAM																
39908-Oth Tang Prop - Appl Software		1995	5,256.00	-	-	0	0.0%									
	39908	1996	0.00	-	-	0	NA	0.0%								
	39908	1997	0.00	-	-	0	NA	NA	0.0%							
	39908	1998	0.00	-	-	0	NA	NA	NA	0.0%						
	39908	1999	0.00	-	-	0	NA	NA	NA	NA	0.0%					
	39908	2000	8,032,596.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%				
	39908	2001	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%			
	39908	2002	9,573,067.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%		
	39908	2003	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	
	39908	2004	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2005	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2006	731,136.00	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2007	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2008	0.00	-	-	0	NA	NA	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2009	0.00	-	-	0	NA	NA	NA	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2010	0.00	-	-	0	NA	NA	NA	NA	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2011	0.00	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2011	0.00	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
	39908	2012	2,603,072.12	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2013	60,097,599.00	-	206	(206)	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2014	-68,544.72	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2015	4,526,869.43	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2016	53,544,165.22	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2017	4,718,848.37	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2018	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2019	3,612,552.62	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2020	3,254,702.42	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2021	0.00	-	-	0	NA	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%
	39908	2022	643,414.10	-	-	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%	0.00%	0.00%	0.00%	0.00%

ATMOS ENERGY CORPORATION
KENTUCKY MID-STATES GENERAL OFFICE
COMPARISON OF EXISTING AND PROPOSED ANNUAL DEPRECIATION ACCRUAL
RATES AND ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2022

	ACCOUNT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	EXISTING ESTIMATES SURVIVOR CURVE	EXISTING ESTIMATES NET SALVAGE PERCENT	EXISTING ESTIMATES CALCULATED ANNUAL ACCRUAL RATE	EXISTING ESTIMATES CALCULATED ANNUAL ACCRUAL AMOUNT	PROPOSED ESTIMATES SURVIVOR CURVE	PROPOSED ESTIMATES NET SALVAGE PERCENT	PROPOSED ESTIMATES CALCULATED ANNUAL ACCRUAL RATE	PROPOSED ESTIMATES CALCULATED ANNUAL ACCRUAL AMOUNT	INCREASE/ (DECREASE)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(2)x(6)	(8)	(9)	(10)	(11)	(12)=(11)-(7)
	GENERAL PLANT											
390.01	STRUCTURES AND IMPROVEMENTS - FRAME	$ 179,339	$ 13,097	40 - R2	(10)	2.47	$ 4,430	40 - R2	(10)	4.40	$ 7,890	$ 3,460
390.04	STRUCTURES AND IMPROVEMENTS - AIR CONDITIONING EQUIPMEI	15,384	10,853	15 - R2	(10)	6.43	989	15 - R2	(10)	4.06	625	(364)
390.09	STRUCTURES AND IMPROVEMENTS - IMPROVEMENTS - LEASED	38,834	38,834	20 - R3	0	5.00	1,942	20 - R3	0	-	* -	(1,942)
391.00	OFFICE FURNITURE AND EQUIPMENT	26,928	4,070	20 - R3	0	5.00	1,346	20 - R3	0	6.43	1,731	385
392.00	TRANSPORTATION EQUIPMENT	27,285	14,272	15 - L3	10	5.41	1,476	12 - L2.5	5	9.09	2,479	1,003
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	110,227	34,405	15 - R5	0	4.82	5,313	15 - R4	0	6.09	6,717	1,404
396.00	POWER OPERATED EQUIPMENT	9,479	1,015	15 - L3	16	5.02	476	15 - L3	5	10.40	986	510
399.03	OTHER TANGIBLE PROPERTY - NETWORK HARDWARE	28,266	6,749	10 - SQ	0	10.00	2,827	10 - R4	0	10.99	3,106	279
399.07	OTHER TANGIBLE PROPERTY - PC SOFTWARE	78,586	55,776	7 - R1.5	0	12.45	9,784	7 - R4	0	13.19	10,366	582
399.08	OTHER TANGIBLE PROPERTY - APPLICATION SOFTWARE	237,875	192,814	12 - R2.5	0	8.33	19,815	10 - R4	0	9.62	22,872	3,057
	TOTAL GENERAL PLANT	**$ 752,202**	**$ 371,885**			**6.43**	**$ 48,397**			**7.55**	**$ 56,772**	**$ 8,375**
	TOTAL DEPRECIABLE PLANT	**$ 752,202**	**$ 371,885**			**6.43**	**$ 48,397**			**7.55**	**$ 56,772**	**$ 8,375**
											Allocation Factor	49.97%
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED											
											Allocated to Kentucky	**$ 4,185**
301.00	ORGANIZATION	$ 185,309										
303.00	MISCELLANEOUS INTANGIBLE PLANT	1,109,552										
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED	**$ 1,294,861**										
	TOTAL GAS PLANT	**$ 2,047,063**	**$ 371,885**									

* NEW ADDITIONS TO THIS ACCOUNT WILL UTILIZE A DEPRECIATION RATE OF 5.00%

Atmos Energy Corporation
2024 Kentucky Rate Case
Plant Ending Balances as of September 30, 2022
Allocation and Impact of the Proposed SSU Depreciation Rates to Kentucky

Line No.	Account	Description	Plant Balances as of 9/30/22	Allocation Factor	Allocated Plant to Kentucky	Current Depr Rates	Annual Accrual	Proposed Depr Rates	Annual Accrual	Increase or (Decrease)
	(a)	(b)	(c)	(d)	(e) = (c) x (d)	(f)	(g) = (e) x (f)	(h)	(i) = (e) x (h)	(j) = (i) - (g)
1		SSU - General Office								
2	39000	Structures and Improvements	$ 5,928,124		$ 270,456	2.38%	$ 6,437	2.38%	$ 6,437	$ -
3	39009	Improvements to Leased Premises	9,896,645		451,511	5.13%	23,163	4.43%	20,002	(3,161)
4	39100	Office Furniture and Equipment	6,120,213		279,220	6.60%	18,429	6.36%	17,758	(670)
5	39200	Transportation Equipment	315,397		14,389	6.29%	905	6.59%	948	43
6	39400	Tools, Shop, and Garage Equipment	76,071		3,471	13.04%	453	12.44%	432	(21)
7	39700	Communication Equipment	543,959		24,817	6.72%	1,668	6.34%	1,573	(94)
8	39800	Miscellaneous Equipment	107,931		4,924	7.24%	357	7.00%	345	(12)
9	39900	Other Tangible Property	-		-	14.96%	-	14.24%	-	-
10	39901	Servers Hardware	36,146,804		1,649,112	13.30%	219,332	12.66%	208,778	(10,554)
11	39902	Servers Software	6,594,516		300,859	10.63%	31,981	10.10%	30,387	(1,595)
12	39903	Network Hardware	4,433,994		202,290	10.34%	20,917	11.28%	22,818	1,902
13	39906	PC Hardware	3,631,674		165,686	17.92%	29,691	19.93%	33,021	3,330
14	39907	PC Software	1,178,940		53,786	10.75%	5,782	11.66%	6,271	489
15	39908	Application Software	90,745,240		4,140,035	7.55%	312,573	6.93%	286,904	(25,668)
16		Total General Office	$ 165,719,509	4.56%	$ 7,560,557		$ 671,685		$ 635,675	$ (36,010)
17										
18		SSU - Greenville Data Center								
19	39005	Structures and Improvements	$ 14,064,998		$ 211,515	2.38%	$ 5,034	2.38%	$ 5,034	$ -
20	39104	Office Furniture and Equipment	82,909		1,247	6.60%	82	6.36%	79	(3)
21		Total Greenville Data Center	$ 14,147,907	1.50%	$ 212,762		$ 5,116		$ 5,113	$ (3)
22										
23		SSU - Distribution & Marketing								
24	39020	Structures and Improvements	$ 2,116		$ 118	2.38%	$ 3	2.38%	$ 3	$ -
25	39029	Improvements to Leased Premises	31,824		1,780	5.13%	91	4.43%	79	(12)
26	39120	Office Furniture and Equipment	263,338		14,727	6.60%	972	6.36%	937	(35)
27	39420	Tools, Shop, and Garage Equipment	-		-	13.04%	-	12.44%	-	-
28	39720	Communication Equipment	8,824		493	6.72%	33	6.34%	31	(2)
29	39820	Miscellaneous Equipment	7,388		413	7.24%	30	7.00%	29	(1)
30	39921	Servers Hardware	1,324,663		74,081	13.30%	9,853	12.66%	9,379	(474)
31	39922	Servers Software	5,425,529		303,421	10.63%	32,254	10.10%	30,646	(1,608)
32	39923	Network Hardware	184,214		10,302	10.34%	1,065	11.28%	1,162	97
33	39926	PC Hardware	376,232		21,041	17.92%	3,770	19.93%	4,193	423
34	39928	Application Software	27,358,036		1,529,990	7.55%	115,514	6.93%	106,028	(9,486)
35		Total Distribution & Marketing	$ 34,982,164	5.59%	$ 1,956,367		$ 163,586		$ 152,487	$ (11,099)
36										

Atmos Energy Corporation
2024 Kentucky Rate Case
Plant Ending Balances as of September 30, 2022
Allocation and Impact of the Proposed SSU Depreciation Rates to Kentucky

Line No.	Account	Description	Plant Balances as of 9/30/22	Allocation Factor	Allocated Plant to Kentucky	Current Depr Rates	Annual Accrual	Proposed Depr Rates	Annual Accrual	Increase or (Decrease)
	(a)	(b)	(c)	(d)	(e) = (c) x (d)	(f)	(g) = (e) x (f)	(h)	(i) = (e) x (h)	(j) = (i) - (g)
37		SSU - Aligne Pipe Project								
38	39931	Servers Hardware	$ 297,267		$ 10,701	13.30%	$ 1,423	12.66%	$ 1,355	$ (68)
39	39932	Servers Software	783,917		28,221	10.63%	3,000	10.10%	2,850	(150)
40	39938	Application Software	21,118,225		760,243	7.55%	57,398	6.93%	52,685	(4,714)
41		Total Aligne Pipe Project	$ 22,199,408	3.60%	$ 799,165		$ 61,821		$ 56,890	$ (4,932)
42										
43		SSU - Customer Support								
44	38900	Land	$ 2,874,240		$ 154,954	0.00%	$ -	0.00%	$ -	$ -
45	39000	Structures and Improvements	13,511,944		728,448	2.38%	17,337	2.38%	17,337	-
46	39009	Improvements to Leased Premises	2,956,107		159,368	5.13%	8,176	4.43%	7,060	(1,116)
47	39100	Office Furniture and Equipment	2,710,774		146,142	6.60%	9,645	6.36%	9,295	(351)
48	39700	Communication Equipment	1,913,117		103,139	6.72%	6,931	6.34%	6,539	(392)
49	39800	Miscellaneous Equipment	85,451		4,607	7.24%	334	7.00%	322	(11)
50	39900	Other Tangible Property	-		-	14.96%	-	14.24%	-	-
51	39901	Servers Hardware	12,194,175		657,405	13.30%	87,435	12.66%	83,227	(4,207)
52	39902	Servers Software	2,208,691		119,074	10.63%	12,658	10.10%	12,026	(631)
53	39903	Network Hardware	721,114		38,876	10.34%	4,020	11.28%	4,385	365
54	39906	PC Hardware	858,992		46,309	17.92%	8,299	19.93%	9,229	931
55	39907	PC Software	-		-	10.75%	-	11.66%	-	-
56	39908	Application Software	102,030,507		5,500,607	7.55%	415,296	6.93%	381,192	(34,104)
57		Total Customer Support	$ 142,065,113	5.39%	$ 7,658,929		$ 570,129		$ 530,614	$ (39,515)
58										
59		SSU - CKV Training Center								
60	38910	Land and Land Rights	$ 1,886,443		$ 56,274	0.00%	$ -	0.00%	$ -	$ -
61	39010	Structures and Improvements	12,586,758		375,475	2.38%	8,936	2.38%	8,936	-
62	39110	Office Furniture and Equipment	583,110		17,395	6.60%	1,148	6.36%	1,106	(42)
63	39210	Transportation Equipment	96,290		2,872	6.29%	181	6.59%	189	9
64	39410	Tools, Shop, and Garage Equipment	641,147		19,126	13.04%	2,494	12.44%	2,379	(115)
65	39710	Communication Equipment	376,253		11,224	6.72%	754	6.34%	712	(43)
66	39810	Miscellaneous Equipment	537,587		16,037	7.24%	1,161	7.00%	1,123	(38)
67	39910	Other Tangible Property	299,459		8,933	14.96%	1,336	14.24%	1,272	(64)
68	39916	PC Hardware	128,382		3,830	17.92%	686	19.93%	763	77
69	39917	PC Software	3,299		98	10.75%	11	11.66%	11	1
70	39918	Application Software	-		-	7.55%	-	6.93%	-	-
71		Total CKV Training Center	$ 17,138,728	2.98%	$ 511,265		$ 16,708		$ 16,492	$ (215)
72										
73		Total SSU Allocated to Kentucky	$ 396,252,829		$ 18,699,045		$ 1,489,046		$ 1,397,271	$ (91,775)