

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-01
Page 1 of 1

REQUEST:

Refer to the Petition, Attachment A. Specifically, the Deviation #1, Capital Structure and Deferred Tax Asset ("DTA") NOL ADIT Adjustments due to Winter Storm Uri, from approved methodologies. Provide evidence in the form of regulatory orders that the \$2.2 billion in debt and associated Accumulated Deferred Income Taxes ("ADIT"), has been assigned, or specifically attributed to recovery in the states of Texas, Kansas, and Colorado.

RESPONSE:

The Texas Railroad Commission issued a Financing Order identifying \$2,021,888,534 of Winter Storm Uri gas costs (Finding of Fact Paragraph 27, Table 1). Please see Attachment 1 for a full copy of the order.

The Company, Commission Staff and Citizens' Utility Ratepayer Board filed a Settlement Agreement on February 8, 2022 identifying \$102,517,847 in Winter Storm Uri gas costs (Appendix A). Please see Attachment 2 for a full copy of the Settlement Agreement.

The Colorado Public Utilities Commission issued an order approving for recovery \$23,549,609 of Winter Storm Uri extraordinary gas costs (paragraph 9.c. of Comprehensive and Uncontested Stipulation and Settlement Agreement) net of existing liabilities due from customers leaving \$13,391,800 for recovery. Please see Attachment 3 for a full copy of the Commission Order and Comprehensive and Uncontested Stipulation and Settlement Agreement.

ATTACHMENTS:

CPAD_1-01_Att1 - TX RRC Financing Order.pdf

CPAD_1-01_Att2 - KS Settlement Agreement.pdf

CPAD_1-01_Att3 - CO Recommended Decision and Settlement.pdf

RAILROAD COMMISSION OF TEXAS

CONSOLIDATED APPLICATIONS FOR	§	
CUSTOMER RATE RELIEF AND RELATED	§	
REGULATORY ASSET DETERMINATIONS IN	§	OS-21-00007061
CONNECTION WITH THE FEBRUARY 2021	§	
WINTER STORM	§	



FINANCING ORDER

RAILROAD COMMISSION OF TEXAS

FEBRUARY 8, 2022

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EXHIBITS

- Exhibit 1: Customer Rate Relief Rate Schedule
- Exhibit 2: Description of Cash Flow Model
- Exhibit 3: Form of True-Up Adjustment Letter
- Exhibit 4: Collection and Reporting Principles
- Exhibit 5: Servicing Agreement Principles

PROPOSED FINANCING ORDER

Notice of Open Meeting to consider this financing order (this “Financing Order”) was duly posted with the Secretary of State within the time period provided by law pursuant to Chapter 551 of the Texas Government Code. The Railroad Commission of Texas (the “Commission”) adopts the following Financing Order, including findings of fact and conclusions of law and orders as follows:

I. INTRODUCTION

This Financing Order addresses the creation and vesting of customer rate relief property as defined in Tex. Util. Code § 104.362(8) (“Customer Rate Relief Property”) in an Issuer Entity (defined below) and the authorization of customer rate relief bonds (the “Customer Rate Relief Bonds”) by the Commission in accordance with Chapter 104, Subchapter I of the Texas Utilities Code (the “Utilities Code”) as added by Texas House Bill 1520 (“H.B. 1520”): (i) to securitize the Regulatory Assets (defined below) relating to Winter Storm Uri and Bond Administrative Expenses (defined below) and other Up-Front Financing Costs (defined below) described in this Financing Order; (ii) to create Customer Rate Relief Property including the right to (A) impose, bill, collect and receive nonbypassable customer rate relief charges consistent with Tex. Util. Code §§ 104.362(7), 104.362(14) and 104.366(c)(9) to be calculated as provided in this Financing Order (the “Customer Rate Relief Charges”) and repaid by customers of gas utilities that have received regulatory asset determinations in amounts sufficient to recover the principal of, and interest on, the Customer Rate Relief Bonds plus Financing Costs (defined below) and Bond Administrative Expenses and other costs as authorized by this Financing Order, and (B) obtain periodic formulaic adjustments to the Customer Rate Relief Charges as provided in this Financing Order; (iii) for approval of the proposed securitization financing structure in accordance with Tex. Util. Code § 104.366(b); and (iv) to approve a rate schedule to implement the Customer Rate Relief Charges.

In February 2021, the North American winter storm known as Winter Storm Uri occurred. Prolonged frigid temperatures and winter precipitation, along with other weather-related effects of the storm, resulted in a dramatic reduction of natural gas availability and a concurrent surge in energy demand by homes, businesses, electric generation plants and electric utilities. In response to the unprecedented market conditions caused by these supply side and demand side shocks, natural gas local distribution companies (“LDCs”) were required to pay extraordinarily high prices

for natural gas in order to meet human needs, customer demand, replace interrupted supply and maintain the integrity of the natural gas system. LDCs are required to pass through the cost of natural gas directly to customers without markup or profit. To mitigate the effect of the extraordinarily high gas costs on customers, the Texas Legislature passed and the Governor signed H.B. 1520, which authorizes securitization financing to provide certain LDC customers with rate relief by extending the period over which the extraordinarily high gas costs related to Winter Storm Uri will be paid for by customers. On June 17, 2021, the Commission issued the H.B. 1520 Notice (defined below), which requested that gas utilities that desired to participate in the regulatory asset determination and securitization process file an application by July 30, 2021.

On July 30, 2021, certain gas utilities referred to as Applicants (defined below) filed individual applications for a regulatory asset determination pursuant to Chapter 104, Subchapter I of the Utilities Code. The Administrative Law Judge (the “ALJ”) consolidated all applications into a Phase 1 regulatory asset determination proceeding (the “Phase 1 proceeding”). Railroad Commission of Texas Staff (“Commission Staff”) and the City of Houston, the Coalition of Texas Municipalities, the City of El Paso, Texas Cities Alliance and the Steering Committee of Cities (together, the “Intervenors”) were granted party status in the Phase 1 proceeding. On October 29, 2021, all parties filed the Settlement Agreement (defined below) and accompanying documents, which resolved all issues related to the determination of the regulatory asset amounts to be recovered by Applicants as contemplated by H.B. 1520. As discussed more fully in this Financing Order, all parties to the Settlement Agreement agreed that the Customer Rate Relief Bonds and the securitization related thereto satisfied applicable statutory requirements under Chapter 104, Subchapter I of the Utilities Code as described in Findings of Fact, Section IV.A.20. A Regulatory Asset Determination Order was issued on November 10, 2021 (the “Regulatory Asset Determination Order”) approving the maximum regulatory asset determination amounts for each Applicant and certain related costs of financing those assets.

This Financing Order complies with the Commission’s statutory requirements to issue a financing order pursuant to Chapter 104, Subchapter I of the Utilities Code and provides a general description of the proposed transaction structure. The proposed transaction structure does not contain every relevant detail and, in certain places, uses only approximations of certain costs and requirements. The final transaction structure will depend, in part, upon the requirements of the nationally recognized credit rating agencies that will rate the Customer Rate Relief Bonds,

decisions made by the Authority (defined below) and the Issuer Entity that will affect the issuance of the Customer Rate Relief Bonds, and market conditions that exist at the time the Customer Rate Relief Bonds are offered to the capital markets by the Issuer Entity.

In this Financing Order, the Commission focuses on the statutory requirements that must be met prior to issuing a financing order, including ensuring that securitization (i) results in tangible and quantifiable benefits to ratepayers; (ii) is the most cost-effective method of funding gas utility reimbursements; and (iii) is in the public interest.

In light of the foregoing, the Commission has established certain criteria in this Financing Order consistent with the statutory requirements set forth in Chapter 104, Subchapter I of the Utilities Code. This Financing Order (i) requests that the Texas Public Finance Authority (the “Authority”) direct the Issuer Entity to issue Customer Rate Relief Bonds in accordance with the requirements of Chapter 1232 of the Texas Government Code, and other provisions of Title 9 of the Texas Government Code, that apply to bond issuance by a state agency consistent with Chapter 104, Subchapter I of the Utilities Code and this Financing Order; (ii) provides for the imposition, billing, collection and receipt of Customer Rate Relief Charges as described in this Financing Order and (iii) provides that each Participating Gas Utility (defined below) shall enter into Collection and Reporting Arrangements (defined below), which shall, without limitation, provide for procedures and other terms substantially consistent with the principles set forth in Exhibit 4 hereto, as a condition precedent to its receipt of proceeds of the Customer Rate Relief Bonds.

II. DISCUSSION AND STATUTORY OVERVIEW

During the 87th Regular Session, the Texas Legislature passed, and the Governor signed H.B. 1520, which authorizes securitization financing to provide customers with rate relief by extending the period over which the extraordinary costs related to Winter Storm Uri may be recovered from customers.

Tex. Util. Code § 104.365 authorized the Commission to determine the regulatory asset amount to be recovered upon application by a gas utility requesting recovery of a regulatory asset related to Winter Storm Uri and set forth certain parameters to be followed to make such determination. As required by Tex. Util. Code § 104.365, the Commission established a schedule, filing requirements and procedures for determining the prudence of the costs to be included in a Participating Gas Utility’s regulatory asset. The Commission, on June 17, 2021, issued the H.B.

1520 Notice. The H.B. 1520 Notice directed that gas utilities were to include only that portion of their regulatory asset balance that reflected extraordinary gas procurement costs incurred during Winter Storm Uri in their application, which could include taxes, financing and other costs incurred to secure and pay for purchased natural gas volumes, carrying costs, and the Applicants' legal and consulting expenses relating to its gas procurement costs and the regulatory asset determination proceeding. The H.B. 1520 Notice further authorized gas utilities to record other extraordinary costs associated with Winter Storm Uri in a separate regulatory asset to be reviewed for reasonableness in each utility's subsequent rate proceeding.

As more fully described in Findings of Fact, Section IV.A, titled "Procedural History: Phase 1, Regulatory Asset Determination Proceeding," on July 30, 2021, eleven Applicants each filed individual applications for a regulatory asset determination pursuant to Chapter 104, Subchapter I of the Utilities Code. During the Phase 1 proceeding, direct testimony was filed by all Applicants, all Intervenors, and Commission Staff. Commission Staff filed direct testimony that stated its position regarding each Applicant's proposed regulatory asset amount and the components of such amount. Such components included extraordinarily high gas costs, interim carrying costs, associated taxes, and legal, consulting and professional expenses. Commission Staff's direct testimony also addressed Intervenor legal, consulting and professional expenses. Commission Staff's direct testimony in the Phase 1 proceeding only addressed costs that are considered Extraordinary Costs,¹ which, for purposes of Chapter 104, Subchapter I of the Utilities Code, are the reasonable and necessary costs related to Winter Storm Uri, including carrying costs, placed in a regulatory asset to be approved by the Commission in the Phase 1 proceeding. Such direct testimony did not specifically address Bond Administrative Expenses and other Financing Costs, which are covered in this Financing Order. On October 29, 2021, the parties filed the Settlement Agreement and accompanying documents, which resolved all issues related to the determination of the regulatory asset amounts, and no issues related to the determination of the regulatory asset amounts or reasonableness, necessity or prudence of the costs in the regulatory assets were preserved for further litigation. The Settlement Agreement specified the total maximum regulatory asset determination amount for each Applicant.² The Settlement Agreement

¹ Tex. Util. Code § 104.363.

² Settlement Agreement, term no. 7.

also specified that the maximum aggregated regulatory asset determination amounts for CoServ (defined below) and TGS (defined below) (in the case of TGS, solely with respect to the West Texas Service Area (“WTSA”)) would not be recovered through the Customer Rate Relief Bonds.³ The remaining Applicants (including TGS, except with respect to the WTSA) are referred to herein as “Participating Gas Utilities”. The regulatory asset determination amounts specified in the Settlement Agreement represent a maximum amount to be recovered by Participating Gas Utilities through the issuance of the Customer Rate Relief Bonds. Such amounts shall be subject to downward adjustments to account for the actual legal, consulting and professional expenses of each Participating Gas Utility.

Various sections of Chapter 104, Subchapter I of the Utilities Code dictate the Commission’s authorization, through a financing order, of the issuance of securities known as Customer Rate Relief Bonds by an issuing financing entity. Customer Rate Relief Bonds (i) are defined as bonds, notes, certificates or other evidence of indebtedness or ownership that are issued under a financing order, the proceeds of which are used directly or indirectly to recover, finance or refinance regulatory assets approved by the Commission, including extraordinary costs and related financing costs;⁴ (ii) are limited to a scheduled final maturity date of no longer than thirty (30) years from the date of issuance of the Customer Rate Relief Bonds, except that the legal final maturity date may be later, based on rating agency and market considerations,⁵ as determined by the Issuer Entity consistent with this Financing Order and within parameters provided to the Issuer Entity by the Authority in accordance with the Authority Bond Standards (defined below) and (iii) are secured by and payable from Customer Rate Relief Property.⁶ The net proceeds from the sale of the Customer Rate Relief Bonds are to be disbursed by the issuing financing entity, net of bond issuance costs, reserves and capitalized interest, to Participating Gas Utilities.⁷ If Customer Rate Relief Bonds are authorized and issued, all existing and future customers receiving service from

³ Settlement Agreement, term nos. 5, 6 and 8.

⁴ Tex. Util. Code § 104.362(6).

⁵ Tex. Util. Code § 104.366(c)(5)(B).

⁶ Tex. Util. Code § 104.362(8).

⁷ Tex. Util. Code §§ 104.366(c)(8); 104.372(b).

any Participating Gas Utility or its successors or assignees (“Successor Utilities”), must pay the principal, interest, extraordinary costs, financing costs, Bond Administrative Expenses and other costs authorized in this Financing Order relating to the Customer Rate Relief Bonds through Customer Rate Relief Charges. As used herein, Successor Utilities shall include any entity that is a successor or assignee of a Participating Gas Utility, including any LDC or other entity that acquires, leases or operates all or part of the gas distribution business of a Participating Gas Utility in the State of Texas; for the avoidance of doubt, Summit Utilities Inc., as the purchaser of certain gas distribution assets of CenterPoint (defined below) in the State of Texas after the issuance of the Regulatory Asset Determination Order, will be deemed a Successor Utility for purposes of this Financing Order and shall be bound by the obligations of a Participating Gas Utility with respect to such acquired gas distribution assets. The term Successor Utilities or Successor Utility shall be applied and interpreted broadly so as to ensure the nonbypassable nature of Customer Rate Relief Charges and prevent any avoidance thereof, and references to Participating Gas Utilities shall be deemed to include all such Successor Utilities. Customer Rate Relief Charges are nonbypassable charges⁸, which will be paid as a component of each Participating Gas Utility’s gas cost, and collected in full by the applicable Participating Gas Utility or a Successor Utility, or a collection agent, as servicer.⁹ Nonbypassable charges are charges that must be paid by all existing and future customers receiving service from Participating Gas Utilities or their Successor Utilities, even if a customer elects to purchase gas from an alternative gas supplier.¹⁰ Customer Rate Relief Charges must be approved by the Commission pursuant to a financing order.¹¹ Customer Rate Relief Bonds are limited obligations of the issuing financing entity and are payable solely from Customer Rate Relief Property and any other money pledged by the issuing financing entity to the payment of the Customer Rate Relief Bonds and are not a debt of the State of Texas, the Commission, the Authority or any gas utility, including any Participating Gas Utility.¹²

⁸ Tex. Util. Code §§ 104.369; 104.362(14).

⁹ Tex. Util. Code § 104.362(7).

¹⁰ Tex. Util. Code § 104.362(14).

¹¹ Tex. Util. Code § 104.366(c)(9).

¹² Tex. Gov’t Code § 1232.1072(i).

The Utilities Code dictates specific findings that the Commission must make when issuing this Financing Order. The Commission must find that the Customer Rate Relief Bond financing for extraordinary costs is the most cost-effective method of funding regulatory asset reimbursements to be made to Participating Gas Utilities.¹³ To make a cost-effectiveness determination, the Commission must find that proposed structuring, expected pricing and proposed financing costs of the Customer Rate Relief Bonds are reasonably expected to provide benefits to customers by (i) considering customer affordability, and (ii) comparing the estimated monthly costs to customers resulting from the issuance of Customer Rate Relief Bonds and the estimated monthly costs to customers that would result from the application of conventional recovery methods.¹⁴ Additionally, the Commission must ensure that securitization provides tangible and quantifiable benefits to customers, greater than would have been achieved absent the issuance of Customer Rate Relief Bonds.¹⁵ Finally, the Commission must make various findings as outlined in Tex. Util. Code § 104.366(c), including that the use of the securitization financing mechanism is in the public interest and consistent with the purposes of Chapter 104, Subchapter I of the Utilities Code.¹⁶

The Applicants included in their direct and rebuttal cases in the Phase 1 proceeding the testimony of Dr. Bruce Fairchild, who testified that the proposed structuring, expected pricing and proposed financing costs of Customer Rate Relief Bonds were the most cost-effective method of funding regulatory asset amounts because recovering the extraordinary costs associated with Winter Storm Uri through a securitization financing provides customers more near term affordability than other conventional methods.¹⁷ As part of the negotiated settlement pursuant to

¹³ Tex. Util. Code § 104.366(a).

¹⁴ Tex. Util. Code § 104.366(b).

¹⁵ Tex. Util. Code § 104.361(b).

¹⁶ Tex. Util. Code § 104.366(c).

¹⁷ Atmos Exhibit 8, pages 29-30.

the Settlement Agreement, all parties agreed to the cost-effectiveness of securitization¹⁸ as reflected in the Regulatory Asset Determination Order.¹⁹

Dr. Fairchild testified that customer rate relief financing provides customers with tangible and quantifiable benefits because using Customer Rate Relief Bonds to finance the regulatory assets is expected to save customers hundreds of millions of present value dollars versus recovery of the extraordinary storm costs through other methods.²⁰ Additionally, Dr. Fairchild testified that, as referenced above, both residential and commercial customers would benefit immediately through lower estimated monthly costs under Customer Rate Relief Bond financing when compared to other conventional methods.²¹ Both of these items are tangible and quantifiable benefits to customers from securitization that are greater than would have been achieved absent the issuance of Customer Rate Relief Bonds. As part of the negotiated settlement, as was the case with the agreement in regards to the cost-effectiveness of securitization, all parties agreed that securitization provides customers tangible and quantifiable benefits²² as reflected in the Regulatory Asset Determination Order.²³

Because financing the regulatory assets through Customer Rate Relief Bonds rather than through conventional methods is both cost-effective and provides customers with tangible and quantifiable benefits, securitization is in the public interest and consistent with the purposes of Chapter 104, Subchapter I of the Utilities Code.

In addition, to further ensure that the structuring, marketing, and pricing of the Customer Rate Relief Bonds are reasonably expected to result in the most cost-effective method of funding regulatory asset reimbursements to Participating Gas Utilities, as more fully described in Findings of Fact, Section IV.D.12, titled “Designated Representative,” an officer or employee of the Commission will be identified as the Designated Representative (together with any successor or,

¹⁸ Settlement Agreement, term no. 9.

¹⁹ Regulatory Asset Determination Order, Finding of Fact no. 76.

²⁰ Atmos Exhibit 8 at 30.

²¹ Atmos Exhibit 8 at 30.

²² Settlement Agreement, term no. 10.

²³ Regulatory Asset Determination Order, Finding of Fact no. 80; Conclusion of Law no. 20.

following the Closing Date as described in Findings of Fact, Section IV.D.12.1, designee, the “Designated Representative”) who will work collaboratively with the Authority and the Issuer Entity during the issuance process for the Customer Rate Relief Bonds (the “Issuance Process”) and thereafter. The Designated Representative will act in a consultative role and provide input and advice to the Authority and/or the Issuer Entity, including providing the advice relating to a target recovery period and amortization methodology described under Findings of Fact, Section IV.D.2.1, adjusting the authorized interest rate described under Findings of Fact, Section IV.D.3 and determining the bond payment periods described in Exhibit 2 hereto. It is reasonable and appropriate that decisions regarding the structuring, marketing and pricing of the Customer Rate Relief Bonds will be made by the Issuer Entity in a manner consistent with parameters provided to the Issuer Entity by the Authority in accordance with the Authority Bond Standards and in accordance with applicable provisions of H.B. 1520 and this Financing Order.²⁴ For the avoidance of doubt, (i) the maximum scheduled final maturity of the Customer Rate Relief Bonds and (ii) the maximum interest rate that the Customer Rate Relief Bonds shall bear shall not exceed the period and rate specified in or determined by the Designated Representative in accordance with this Financing Order. The Designated Representative may also specify any successor officer or employee of the Commission to serve in the role as Designated Representative as well as designate other staff, legal counsel, financial advisors and other consultants, to (A) assist the Commission in the Issuance Process for the Customer Rate Relief Bonds and (B) act as its designee after the Closing Date. Any costs incurred by the Commission and/or its Designated Representative in connection with the Customer Rate Relief Bonds, including those of its legal counsel, financial advisors and other consultants, shall be treated as Financing Costs (defined below). Further, as more fully described in Findings of Fact, Section IV.D.11, titled “Issuance Summary,” the Authority, in accordance with its statutory obligations,²⁵ shall deliver to and file with the Commission an Issuance Summary (defined below), and such Issuance Summary shall include a description of each series of Customer Rate Relief Bonds, total principal amount, Up-Front Financing Costs, estimated Ongoing Financing Costs (defined below), maturity, credit enhancements, weighted average life, call provisions and amortization schedules.

²⁴ Tex. Util. Code § 104.366(f).

²⁵ Tex. Gov’t Code § 1232.1072(m); Tex. Util. Code §§ 104.373(b).

As discussed in this Financing Order, the Commission finds that the securitization approved in this Financing Order meets the requirements of Chapter 104, Subchapter I of the Utilities Code. Accordingly, the Commission (i) approves the securitization of (A) the Aggregated Regulatory Asset Determination Amounts as set forth in Table 4 under Findings of Fact, Section IV.A.35 (not to exceed \$3,385,355,729 in the aggregate) in accordance with Tex. Util. Code § 104.366(c)(5), Chapter 103, Subchapter A of the Utilities Code and Commission Rule 16 Tex. Admin. Code § 7.5530, plus (B) all Up-Front Financing Costs, including, without limitation, all Bond Administrative Expenses to be paid from the proceeds of the Customer Rate Relief Bonds, reimbursements to the Authority, the Issuer Entity and the Commission for any financing costs incurred for the issuance of the Customer Rate Relief Bonds, amounts to fund any reserve established under the indenture under which the Customer Rate Relief Bonds are issued (the “Indenture”) and/or ancillary agreements (as defined in Tex. Util. Code § 104.362(1)) (“Ancillary Agreements”), and any capitalized interest for the period determined in accordance with this Financing Order, if applicable, (the aggregate amount described in this clause (i), the “Authorized Amount”); (ii) authorizes, subject to the terms of this Financing Order, the issuance of Customer Rate Relief Bonds in one or more series, and in one or more tranches or classes for such series, in an aggregate amount not to exceed the Authorized Amount, to be issued by a special purpose issuing financing entity created by the Authority in accordance with Tex. Gov’t Code § 1232.1072; (iii) approves Customer Rate Relief Charges in an amount to be calculated as provided in this Financing Order; and (iv) approves the Customer Rate Relief Rate Schedule for each of the Participating Gas Utilities to implement those Customer Rate Relief Charges.

Because the actual structure and pricing of the Customer Rate Relief Bonds and the precise amounts to be securitized are unknown at the time this Financing Order is issued, following determination of the final terms of the Customer Rate Relief Bonds, it is appropriate for the Authority or the Issuer Entity on its behalf to deliver to and file with the Commission no later than five (5) business days after the Closing Date (defined below), the Issuance Summary, and, when available, copies of all publicly filed bond issuance documents.

This Financing Order provides that Customer Rate Relief Charges will be collected and allocated among the customers of each Participating Gas Utility through uniform monthly volumetric charges to be paid by customers as a component of the Participating Gas Utilities’ gas

cost.²⁶ The Customer Rate Relief Charges will be billed and collected by each Participating Gas Utility or its Successor Utilities as provided in this Financing Order and remitted to the Trustee (defined below) as provided in this Financing Order. The Customer Rate Relief Charges will be Customer Rate Relief Property of the Issuer Entity pledged to secure the payment of the Customer Rate Relief Bonds.²⁷

This Financing Order also includes a mechanism for the imposition, collection and periodic formulaic adjustments, on at least an annual basis, of Customer Rate Relief Charges as required under Tex. Util. Code § 104.366(c)(6) that will correct any overcollections or undercollections and to ensure the expected recovery of amounts sufficient to provide for the timely payment of all debt payments, other Ongoing Financing Costs, Bond Administrative Expenses and other costs approved in this Financing Order in connection with the Customer Rate Relief Bonds. In addition to the required annual reviews, more frequent reviews are authorized to ensure that the amounts of the Customer Rate Relief Charges match the funding requirement in this Financing Order.

This Financing Order, together with the Customer Rate Relief Property and Customer Rate Relief Charges authorized by this Financing Order, is irrevocable and not subject to reduction, impairment, or adjustment by further action of the Commission, other than as permitted in connection with the true-up mechanism authorized by this Financing Order, and is not subject to rehearing by the Commission. The Financing Order shall be transmitted to the Authority after all appeals thereto have been exhausted and only a party to the Phase 1 proceeding may file such an appeal, although under the Settlement Agreement, the parties' thereto agreed not to appeal any aspect of the Financing Order to the extent it is not inconsistent with the Settlement Agreement.²⁸ The State of Texas, including the Commission and the Authority, has pledged for the benefit and protection of the financing parties (as defined in H.B. 1520) and the Participating Gas Utilities that the State will not take or permit any action that would impair the value of Customer Rate Relief Property, or, except for the true-up mechanism expressly allowed by law, reduce, alter, or impair the Customer Rate Relief Charges to be imposed, collected and remitted to financing parties, until the principal, interest and any other charges incurred and contracts to be performed in connection

²⁶ Tex. Util. Code § 104.366(c)(9).

²⁷ Section 104.366(c)(7).

²⁸ Settlement Agreement, term no. 19.

with the Customer Rate Relief Bonds have been paid and performed in full.²⁹ Pursuant to Tex. Util. Code § 104.374(b), the Issuer Entity will include this pledge in any documentation relating to Customer Rate Relief Bonds, including the Indenture.

As provided in H.B. 1520, Customer Rate Relief Property constitutes a present property right for purposes of contracts concerning the sale or pledge of property and the property will continue to exist for the duration of the pledge of the State of Texas and its agencies as described in the preceding paragraph.³⁰ In addition, the interest of the Issuer Entity or any pledgee, such as an indenture trustee, in Customer Rate Relief Property (as well as the revenues and collections arising from Customer Rate Relief Charges) is not subject to setoff, counterclaim, surcharge, or defense by any gas utility or any other person or in connection with the bankruptcy of a Participating Gas Utility, the Authority, the Issuer Entity or any other entity.³¹ Further, all revenue and collections resulting from Customer Rate Relief Charges constitute proceeds only of a property right arising from this Financing Order.³² This Financing Order will remain in effect, unabated, notwithstanding the bankruptcy of any Participating Gas Utility, the Authority, Issuer Entity, or any successor or assignee of any gas utility, the Authority or Issuer Entity.³³ Further, receipt of Customer Rate Relief Charges by a Participating Gas Utility is exempt from state and local sales taxes and use and utility gross receipts taxes and assessments, and is excluded from revenue for purposes of state franchise tax.³⁴ The creation, granting, perfection and enforcement of liens and security interests in Customer Rate Relief Property that secures the Customer Rate Relief Bonds are governed by Chapter 1208 of the Texas Government Code and the Customer Rate Relief Property does not constitute an account or general intangible under Tex. Bus. & Com. § 9.106.³⁵

²⁹ Tex. Util. Code § 104.374(b).

³⁰ Tex. Util. Code § 104.367(d).

³¹ Tex. Util. Code § 104.368.

³² Tex. Util. Code § 104.367(e).

³³ Tex. Util. Code § 104.368.

³⁴ Tex. Util. Code § 104.375(b).

³⁵ Tex. Util. Code § 104.371(a).

III. DESCRIPTION OF PROPOSED TRANSACTION

A brief summary of the proposed transaction is provided in this section. A more detailed description is included in the Findings of Fact, Section IV.D, titled “Proposed Structure of Securitization”.

To facilitate the proposed securitization and pursuant to Chapter 1232, Subchapter C, Section 1232.1072 of the Texas Government Code, codified by H.B. 1520, the Authority has caused a certificate of formation to be filed with the Texas Secretary of State to form the “Texas Natural Gas Securitization Finance Corporation” (the “Issuer Entity”) as a special purpose issuing financing entity for the purpose of issuing the Customer Rate Relief Bonds approved pursuant to this Financing Order and owning the Customer Rate Relief Property. The Issuer Entity is a duly constituted public authority and instrumentality of the State of Texas and a non-profit corporation organized under and governed by the Business Organizations Code.³⁶ The Issuer Entity is governed by a governing board of three (3) members appointed by the Authority. The Issuer Entity shall keep its assets and liabilities separate and distinct from those of any other person, including the Authority and any other public authority or instrumentality of the State.³⁷ The Customer Rate Relief Property, including the rights to impose, bill, collect and receive Customer Rate Relief Charges, and to obtain periodic adjustments to those Customer Rate Relief Charges, along with the other rights arising pursuant to this Financing Order will be owned by and vested *ab initio* in the Issuer Entity.³⁸ The Issuer Entity will be authorized to pledge Customer Rate Relief Property to secure the payment of the Customer Rate Relief Bonds,³⁹ but will not otherwise transfer any interest in the Customer Rate Relief Property unless such transfer is made in accordance with the Indenture. The Customer Rate Relief Property does not constitute property of the Commission or any gas utility, including any Participating Gas Utility.⁴⁰ The Authority will direct the Issuer Entity to issue Customer Rate Relief Bonds upon the request of the Commission and to transfer the net

³⁶ Tex. Gov’t Code § 1232.1072(e).

³⁷ Tex. Gov’t Code § 1232.1072(p).

³⁸ Tex. Util. Code § 104.366(c)(7).

³⁹ Tex. Util. Code § 104.367(d).

⁴⁰ Tex. Util. Code § 104.364(c).

proceeds from the sale of the Customer Rate Relief Bonds, as set forth in this Financing Order, after payment of Up-Front Financing Costs, to the Participating Gas Utilities to fully reimburse them for their Aggregated Regulatory Asset Determination Amount as set forth in Table 4 under Findings of Fact, Section IV.A.35, after giving effect to the actual legal, consulting and professional expenses as described in Findings of Fact, Section IV.A.36.

The Customer Rate Relief Bonds will be issued pursuant to the Indenture and administered by an indenture trustee (the “Trustee”). The Customer Rate Relief Bonds will be secured by and payable solely out of the Customer Rate Relief Property created pursuant to this Financing Order and other collateral of the Issuer Entity described in this Financing Order, including any debt service or other reserves created in connection with the Customer Rate Relief Bonds.⁴¹ That collateral will be pledged to the Trustee for the benefit of the holders of the Customer Rate Relief Bonds and to secure the payment of principal and interest on the Customer Rate Relief Bonds and all related Financing Costs, as authorized in this Financing Order.

The Customer Rate Relief Charges will be billed and collected by the Participating Gas Utilities and their Successor Utilities as collection agents for the Central Servicer acting on behalf of the Issuer Entity as the owner of the Customer Rate Relief Property, in accordance with the terms of this Financing Order, including the Collection and Reporting Arrangements (defined below).⁴² Each Participating Gas Utility, as collection agent, will bill, collect and remit the Customer Rate Relief Charges and comply with related reporting requirements pursuant to a collection and reporting agreement and further agreements, instruments and other arrangements (collectively, the “Collection and Reporting Arrangements”) between the Central Servicer and such Participating Gas Utility, as determined by the Issuer Entity to be necessary or convenient to execute the transactions authorized by this Financing Order. The foregoing determination and other determinations relating to the methods of sale, types of bonds, bond forms, interest rates, principal amortization, amount of reserves or capitalized interest, and other terms of the Customer Rate Relief Bonds that are subject to the Authority Bond Standards may be made by the Authority or by the Issuer Entity to the extent statutory duties of the Authority under Tex. Util. Code § 104.366(f)(2) are delegated to the Issuer Entity (each such delegation, an “ABS Delegation”).

⁴¹ Tex. Gov’t Code § 1232.1072(i).

⁴² Tex. Util. Code § 104.373.

Such Collection and Reporting Arrangements shall, without limitation, provide for procedures and other terms substantially consistent with the principles set forth in Exhibit 4 hereto. The execution and delivery of such Collection and Reporting Arrangements by a Participating Gas Utility shall be a condition precedent to the receipt of proceeds of the Customer Rate Relief Bonds by it. The Central Servicer of the Customer Rate Relief Bonds, as identified in this Financing Order, will be responsible for, among other things, (i) calculating the True-Up Adjustments (defined below) and delivering the related true-up adjustment letters substantially in the form of Exhibit 3 hereto (“True-Up Adjustment Letters”) to the Commission, the Authority, the Issuer Entity, the Participating Gas Utilities and, as applicable, their Successor Utilities and the Trustee, (ii) monitoring and verifying the remittance of the Customer Rate Relief Charges to the Issuer Entity or Trustee and (iii) entering into Collection and Reporting Arrangements with each of the Participating Gas Utilities, in each case, in accordance with the Servicing Agreement which shall, without limitation, provide for terms substantially consistent with the principles set forth in Exhibit 5 hereto.⁴³ If the Central Servicer defaults on its obligations under the Servicing Agreement and such default is a “Central Servicer Default”, as described in Exhibit 5 hereto, the Commission shall promptly identify potential alternate candidates to replace the defaulting Central Servicer and such candidates shall be appointed in accordance with the terms of the Servicing Agreement. Pursuant to Tex. Util. Code § 104.362(17), the Commission identifies any of Bank of New York Mellon Corporation, U.S. Bank National Association and Alter Domus (US) LLC (or, in each case, an appropriate affiliate thereof) or such other financial institution or professional service firm possessing the requisite experience and qualifications, consistent with achieving the highest possible rating on the Customer Rate Relief Bonds, as entities that may be engaged pursuant to the Servicing Agreement to act as the initial Central Servicer.

As more fully set forth in the Servicing Agreement, the Central Servicer of the Customer Rate Relief Bonds will be responsible for coordinating with and monitoring and verifying the remittance of the Customer Rate Relief Charges by each of the Participating Gas Utilities as collection agents to the Issuer Entity or the Trustee. Each Participating Gas Utility shall include the applicable Customer Rate Relief Charge in the gas cost charge or equivalent charge on customer bills and collect the applicable Customer Rate Relief Charge for the ultimate benefit and

⁴³ Tex. Util. Code § 104.366(d).

account of the Issuer Entity in accordance with the Collection and Reporting Arrangements. Pursuant to the Servicing Agreement, the Central Servicer will be authorized to, among other things, enter into Collection and Reporting Arrangements with Participating Gas Utilities in furtherance of the collection and remittance of the Customer Rate Relief Charges, the calculation of true-up adjustments and the provision of other information (including forecast data required for calculating true-up adjustments) necessary for the Central Servicer to perform its obligations and required for statutory reporting obligations. In the event of noncompliance by any Participating Gas Utility with its Collection and Reporting Arrangements and upon written request to the Commission by the Central Servicer, the Issuer Entity or the Trustee, the Commission will act promptly to enforce the obligations of the Participating Gas Utility thereunder.

Customer Rate Relief Charges will be calculated to ensure the collection of amounts sufficient to pay the principal of and interest on the Customer Rate Relief Bonds in accordance with their terms and all other Ongoing Financing Costs, including all fees, costs and expenses of the Authority, the Issuer Entity and the Commission and any of their advisors and legal counsel, associated with the issuance and ongoing administration of the Customer Rate Relief Bonds.⁴⁴ The costs will be collected from sales customers of each Participating Gas Utility through uniform monthly volumetric charges to be paid by customers as a component of such Participating Gas Utility's gas costs.⁴⁵ The Customer Rate Relief Charges will be calculated by the Central Servicer pursuant to the mechanism described in the Customer Rate Relief Rate Schedule (attached hereto as Exhibit 1). In addition to the required annual true-up set forth in this Financing Order pursuant to Tex. Util. Code § 104.370, additional periodic true-ups may be performed by the Central Servicer, in accordance with the mechanism described in the Customer Rate Relief Rate Schedule, to correct any overcollections or undercollections and ensure that the amount collected from Customer Rate Relief Charges is sufficient to provide for the timely payment of the Customer Rate Relief Bonds and pay related Financing Costs. The methodology for making Scheduled True-Up Adjustments (defined below) and Interim True-Up Adjustments (defined below) and the circumstances under which each shall be made are described in the Cash Flow Model, attached as Exhibit 2 hereto, and the Customer Rate Relief Rate Schedule. The bond issuance documents,

⁴⁴ Tex. Util. Code § 104.366(e).

⁴⁵ Tex. Util. Code § 104.373(a).

including the Servicing Agreement, shall provide for True-Up Adjustments in a manner consistent with this paragraph.

To permit underwriters to purchase the Customer Rate Relief Bonds pursuant to state and federal securities laws and regulations (specifically, regulation 17 CFR § 240.15c2-12 (“Rule 15c2-12”), the Participating Gas Utilities (collectively, along with any Successor Utilities, the “Continuing Disclosure Participants”) may be required by such underwriters and the Issuer Entity to enter into agreements binding against such Continuing Disclosure Participants for the life of the Customer Rate Relief Bonds to provide certain information to the Issuer Entity reasonably determined by the Issuer Entity to be necessary to comply with such laws and regulations. The Issuer Entity will negotiate with such underwriters and the Continuing Disclosure Participants, as applicable, the terms of such ongoing disclosure requirements in order to facilitate the offer and sale of the Customer Rate Relief Bonds. Any of the Participating Gas Utilities that are determined by the Issuer Entity to be Continuing Disclosure Participants shall cooperate with the Issuer Entity with respect to such disclosure requirements and provide information determined to be necessary by the Issuer Entity with respect to such continuing disclosure pursuant to agreements entered into with the Issuer Entity.

As provided in H.B. 1520 and this Financing Order, the Customer Rate Relief Bonds can be issued in one or more series, and in one or more tranches or classes for such series, in an aggregate amount not to exceed the Authorized Amount approved by this Financing Order bearing a fixed interest rate, to be determined by the Issuer Entity subject to the limitations set forth in this Financing Order and within parameters provided to the Issuer Entity by the Authority in accordance with the Authority Bond Standards.

Financing costs associated with the issuance of the Customer Rate Relief Bonds, including all Bond Administrative Expenses to be paid or reimbursed to the Authority, the Issuer Entity or the Commission from the proceeds of the Customer Rate Relief Bonds, are statutorily authorized under H.B. 1520 to be securitized and added to the principal amount of the Customer Rate Relief Bonds as provided in Tex. Util. Code § 104.366(e). In accordance with H.B. 1520 and as set forth in Ordering Paragraph A.1 (including references to other ordering paragraphs therein) of this Financing Order, such financing costs and Bond Administrative Expenses shall include amounts for (i) the cost of original issue discount, credit enhancements, reserves established under the Indenture or Ancillary Agreements and other arrangements to enhance marketability of the

Customer Rate Relief Bonds as discussed in Ordering Paragraph C.3.; (ii) the cost of the Authority's, the Issuer Entity's and the Commission's financial advisors and legal counsel; and (iii) any costs incurred by the Commission, the Authority or the Issuer Entity if this Financing Order is appealed.

The Authority, the Commission and the Issuer Entity are statutorily permitted to recover under H.B. 1520, directly through the Customer Rate Relief Charges, all Up-Front Financing Costs (defined below) that exceed costs financed with the proceeds of the Customer Rate Relief Bonds. In addition, under H.B. 1520, the Authority, the Commission and the Issuer Entity are statutorily permitted to recover, directly through Customer Rate Relief Charges, all Ongoing Financing Costs related to, among other things, administering the Customer Rate Relief Bonds, including fees, costs and expenses of the Central Servicer, its advisors, consultants and any advisors or legal counsel hired by the Commission, the Authority or Issuer Entity, related to and incurred during the life of the Customer Rate Relief Bonds.

IV. FINDINGS OF FACT

A. Procedural History: Phase 1, Regulatory Asset Determination Proceeding

1. On June 17, 2021, the Commission issued a Notice to Gas Utilities, *Procedures for Gas Utilities to File an Application for Regulatory Asset Determination Pursuant to H.B. No. 1520, Texas Utilities Code, Chapter 104, Subchapter I, and Participate in Securitization of Extraordinary Costs Incurred as a Result of the February 2021 Winter Weather Event* ("H.B. 1520 Notice"). The H.B. 1520 Notice established a procedure for gas utilities desiring to participate in securitization pursuant to H.B. 1520 to file an application for regulatory asset determination. The H.B. 1520 Notice listed required information to be included in any application for regulatory asset determination.
2. On July 30, 2021, AgriTexGas, L.P. ("AgriTexGas"); Atmos Energy Corporation ("Atmos Energy") on behalf of its Mid-Tex Division and West Texas Division; Rocking M Gas LLC d/b/a Bluebonnet Natural Gas LLC ("Bluebonnet"); CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex, CenterPoint Energy Arkla, and CenterPoint Energy Texas Gas ("CenterPoint"); Corix Utilities (Texas) Inc. ("Corix"); CoServ Gas, Ltd. ("CoServ"); EPCOR Gas Texas Inc. ("EPCOR"); NatGas, Inc. ("NatGas"); SiEnergy, LP

(“SiEnergy”); Texas Gas Service Company, a Division of ONE Gas, Inc. (“TGS”); and Universal Natural Gas, LLC d/b/a Universal Natural Gas, Inc. (“UniGas”) (collectively, the “Applicants”) each filed individual applications for a regulatory asset determination pursuant to Chapter 104, Subchapter I of the Utilities Code.

3. The eleven applications were timely filed pursuant to Tex. Util. Code § 104.365 and the Commission’s H.B. 1520 Notice.
4. The eleven applications requested a Commission determination that the extraordinary costs included in each Applicant’s regulatory asset account were reasonable and prudently incurred and were costs that would not have been incurred but for Winter Storm Uri. Each Applicant also pled that securitization is cost-effective, that securitization provides tangible and quantifiable benefits for customers greater than would be achieved absent the issuance of Customer Rate Relief Bonds and that securitization is in the public interest and consistent with the purposes of Chapter 104, Subchapter I of the Utilities Code.
5. The following parties filed motions to intervene and were granted interventions on the following dates: Commission Staff on August 9, 2021; the City of Houston (“COH”) on August 9, 2021; the Coalition of Texas Municipalities (“CTM”)⁴⁶ on August 9, 2021; the Texas Cities Alliance (“TCA”)⁴⁷ on August 9, 2021; the City of El Paso on August 9, 2021;

⁴⁶ CTM is comprised of the Cities of Austin, Balch Springs, Bandera, Bartlett, Belton, Blooming Grove, Burnet, Cameron, Cedar Park, Clifton, Commerce, Copperas Cove, Corsicana, Electra, Fredericksburg, Gatesville, Glen Rose, Goldthwaite, Granbury, Greenville, Groesbeck, Hamilton, Heath, Henrietta, Hickory Creek, Hico, Hillsboro, Hutto, Kerens, Lampasas, Leander, Lometa, Longview, Marble Falls, Mare, Mexia, Oney, Point, Pflugerville, Princeton, Ranger, Rice, Riesel, Rockdale, Rogers, Round Rock, San Angelo, Sanger, Somerville, Star Harbor, Trinidad, Whitney, Amarillo, Channing, Dalhart, Lubbock, Alice, Austin, Bastrop, Buda, Cibolo, Jourdan, Kyle, New Braunfels, San Marcos, Seguin, Smithville, Universal City, Atlanta, Center, Crockett, Daingerfield, Jacksonville, Kilgore, Lone Star, Lufkin, Marshall, Mineola, Mt. Pleasant, Nacogdoches, Overton, Ruse, White Oak, Angleton, Baytown, Clute, Freeport, League City, Pearland, Shoreacres, West Columbia, Wharton, La Porte, Pasadena, and Borger.

⁴⁷ TCA is comprised of the cities of Abilene, Addison, Albany, Allen, Alvarado, Angus, Anna, Argyle, Arlington, Aubrey, Azele, Bedford, Bellmead, Benbrook, Beverly Hills, Blossom, Blue Ridge, Bowie, Boyd, Bridgeport, Brownwood, Bryan, Buffalo, Burk Burnett, Burleson, Caddo Mills, Canton, Carrollton, Cedar Hill, Celeste, Celina, Centerville, Cisco, Clarksville, Cleburne, Clyde, College Station, Colleyville, Colorado City, Comanche, Commerce, Coolidge, Coppell, Corinth, Crandall, Cross Roads, Crowley, Dalworthington, Gardens, Denison, Denton, DeSoto, Draper, Duncanville, Early, Eastland, Edgecliff Village, Emory, Ennis, Euless, Everman, Fairview, Farmers Branch, Farmersville, Fate, Flower Mound, Forest Hill, Forney, Fort Worth, Frisco, Frost, Gainesville, Garrett, Georgetown, Glenn Heights, Grand Prairie, Grapevine, Groesbeck, Gunter, Haltom City, Harker Heights, Haskell, Haslet, Hewitt, Highland Park, Highland Village, Honey Grove, Hurst, Hutto, Iowa Park, Irving, Justin, Kaufman, Keene, Keller, Kemp, Kennedale, Kerens, Kerrville, Killen, Krum, Lakeside, Lake Dallas, Lake Worth, Lancaster, Lavon,

and the Steering Committee of Cities (“SCC”)⁴⁸ on August 20, 2021 (collectively, the “Intervenors”).

6. On August 4, 2021, the eleven individual proceedings were consolidated into the following proceeding: *OS-21-00007061, Consolidated Application for Customer Rate Relief and Related Regulatory Asset Determination in Connection with the February 2021 Winter Storm*.
7. A prehearing conference was held on August 13, 2021.
8. On September 15, 2021, Applicant AgriTexGas moved to withdraw its application, withdraw as a party, and be relieved of any obligations to respond to any pending discovery. The motion was granted on September 20, 2021.
9. On September 20, 2021, Applicant NatGas moved to withdraw its application, withdraw as a party, and be relieved of any obligations to respond to any pending discovery. The motion was granted on September 22, 2021.
10. On September 30, 2021, COH, the City of El Paso, TCA, and CTM filed direct testimony in the regulatory asset determination proceeding. SCC filed a statement of position.
11. On October 12, 2021, Commission Staff filed direct testimony in the regulatory asset determination proceeding.
12. On October 14, 2021, the ALJ issued a Notice of Hearing.
13. On October 25, 2021, the Applicants filed rebuttal testimony.

Lewisville, Little Elm, Lorena, Madisonville, Malakoff, Mansfield, McKinney, Melissa, Midlothian, Murphey, Newark, Nacona, North Richland Hills, Northlake, Oak Leaf, Ovilla, Palestine, Pantego, Paris, Parker, Pecan Hill, Petrolia, Plano, Ponder, Pottsboro, Prosper, Quitman, Red Oak, Reno (Parker County), Rhome, Richardson, Richland, Richland Hills, River Oaks, Roanoke, Robinson, Rockwall, Rosco, Rowlett, Royse City, Sachse, Saginaw, Sansom Park, Seagoville, Sherman, Snyder, Southlake, Sulphur Springs, Sweetwater, Temple, Terrell, The Colony, Trophy Club, Tyler, University Park, Venus, Vernon, Waco, Watauga, Waxahachie, Westlake, Westover Hills, Westworth Village, Whitesboro, White Settlement, Wichita Falls, Wilmer, Woodway, and Wylie.

⁴⁸ SCC is comprised of Beaumont, Groves, Nederland, Port Arthur, and Port Neches.

14. On October 27, 2021, the ALJ was notified that the parties had reached a settlement in principle.
15. On October 29, 2021, the parties filed a *Unanimous Stipulation and Settlement Agreement* (the “Settlement Agreement”) and accompanying documents, which resolved all issues related to the determination of the regulatory asset amounts, and no issues related to the determination of the regulatory asset amounts or reasonableness, necessity or prudence of the costs in the regulatory assets were preserved for further litigation.
16. The Settlement Agreement memorialized the agreement of the parties that the costs incurred by all Applicants to purchase natural gas volumes during February 2021 were reasonable, necessary and prudently incurred.⁴⁹
17. The Settlement Agreement memorialized the agreement of the parties that TGS reduce its regulatory asset amount by removing the WTSA extraordinary costs from securitization.⁵⁰ TGS, Commission Staff, and the City of El Paso agreed that TGS will separately recover its extraordinary costs for the WTSA from customers within the WTSA.⁵¹
18. The Settlement Agreement memorialized the agreement of the parties that CoServ would remove its regulatory asset amount from securitization and would not participate in any customer rate relief financing transaction.⁵² CoServ and Commission Staff agreed that CoServ will separately recover its regulatory asset amount from customers within its service area.⁵³

⁴⁹ Settlement Agreement, term no. 1.

⁵⁰ Settlement Agreement, term no. 4.

⁵¹ Settlement Agreement, term no. 5.

⁵² Settlement Agreement, term no. 6.

⁵³ Settlement Agreement, term no. 6.

19. The Settlement Agreement stated the parties' agreement of a maximum stipulated regulatory asset amount for each Applicant for recovery and use in a subsequent financing order.⁵⁴
20. The Settlement Agreement stated the parties' agreement (i) that Customer Rate Relief Bond financing is the most cost-effective and affordable method of funding regulatory asset reimbursements to Applicants other than CoServ and TGS WTSA;⁵⁵ (ii) that securitization provides tangible and quantifiable benefits to customers greater than would have been achieved absent the issuance of Customer Rate Relief Bonds;⁵⁶ (iii) that the terms of the Settlement Agreement are fair, reasonable, in the public interest and consistent with the provisions of H.B. 1520;⁵⁷ and (iv) to support the issuance of Customer Rate Relief Bonds with maturity terms not to exceed thirty (30) years.⁵⁸
21. The Settlement Agreement stated the parties' agreement not to appeal any aspect of a Commission financing order provided that the Commission's financing order is not inconsistent with the Settlement Agreement.⁵⁹
22. On November 1, 2021, the ALJ held a prehearing conference.
23. On November 2, 2021, the ALJ held a hearing on the merits in the regulatory asset determination phase. Each Applicant, each Intervenor, and Commission Staff offered its exhibits into the record and all exhibits, including the Settlement Agreement, were admitted without objection. The ALJ took official notice of seventy-two (72) written public comments received by the Commission prior to the hearing.

⁵⁴ Settlement Agreement, term no. 7.

⁵⁵ Settlement Agreement, term no. 9.

⁵⁶ Settlement Agreement, term no. 10.

⁵⁷ Settlement Agreement, term no. 21.

⁵⁸ Settlement Agreement, term no. 11.

⁵⁹ Settlement Agreement, term no. 19.

24. On November 2, 2021, the ALJ closed the evidentiary record.
25. On November 3, 2021, the parties jointly filed a *Proposed Regulatory Asset Determination Order* and accompanying documents.
26. On November 10, 2021, at its open meeting, the Commission issued the *Regulatory Asset Determination Order*.
27. The Regulatory Asset Determination Order ordered the following maximum regulatory asset determination amounts for each Applicant:

Table 1. Maximum Regulatory Asset Determination Amounts

Applicant	Maximum Regulatory Asset Determination Amount
Atmos Energy.....	\$ 2,021,888,534
Bluebonnet	\$ 1,962,731
CenterPoint.....	\$ 1,099,929,626
Corix.....	\$ 294,407
EPCOR.....	\$ 11,296,221
SiEnergy	\$ 18,795,497
TGS	\$ 197,342,375
UniGas.....	\$ 32,431,370

28. The maximum regulatory asset determination amounts for each Applicant in Table 1 were based on the amounts agreed by each party to the Settlement Agreement. The regulatory asset determination order amounts as set forth in the Settlement Agreement and the Regulatory Asset Determination Order were the product of a negotiated \$10 million reduction to Commission Staff's regulatory asset determination amounts recommended in its filed direct testimony.⁶⁰ Commission Staff's recommended maximum regulatory asset determination amounts were based on the following components of extraordinary costs: (i)

⁶⁰ Settlement Agreement, term no. 2.

the extraordinary gas procurement costs; (ii) financing and carrying costs; (iii) taxes; and (iv) legal, consulting and professional expenses.

29. The Regulatory Asset Determination Order, consistent with Commission Staff testimony, ordered maximum regulatory asset amounts for each Applicant to allow Applicants to update their estimated legal, consulting and professional expenses with actual expenses within thirty-five (35) days of the issuance date of this Financing Order.⁶¹
30. The Regulatory Asset Determination Order ordered maximum Applicant legal, consulting and professional expenses in the following Table 2 amounts, which are included in the Maximum Regulatory Asset Determination Amounts in Table 1:⁶²
31. The Regulatory Asset Determination Order ordered the following maximum applicant legal, consulting and professional expenses for each Applicant:

Table 2. Maximum Applicant Legal, Consulting, and Professional Expenses

Applicant	Maximum Applicant Legal, Consulting, and Professional Expenses
Atmos Energy	\$ 552,000
Bluebonnet.....	\$ 92,795
CenterPoint.....	\$ 3,106,212
Corix	\$ 61,000
EPCOR	\$ 82,043
SiEnergy	\$ 133,392
TGS	\$ 1,333,719
UniGas.....	\$ 410,997

32. The Regulatory Asset Determination Order ordered maximum Intervenor legal, consulting and professional expenses for each Intervenor to allow Intervenor to update their

⁶¹ Regulatory Asset Determination Order, Finding of Fact no. 53.

⁶² Regulatory Asset Determination Order, Finding of Fact no. 84.

estimated legal, consulting and professional expenses with actual expenses incurred through the issuance date of this Financing Order.⁶³

33. The Regulatory Asset Determination Order ordered maximum Intervenor legal, consulting and professional expenses in the following amounts:⁶⁴

Table 3. Maximum City Intervenor Legal, Consulting and Professional Expenses

Intervenor	Maximum City Intervenor Legal, Consulting and Professional Expenses
COH	\$423,550
TCA.....	\$648,464
CTM.....	\$309,698
SCC	\$33,256

34. The Regulatory Asset Determination Order determined it was reasonable for Atmos Energy, CenterPoint and TGS to reimburse the Intervenor in an amount up to the Maximum City Intervenor Legal, Consulting and Professional Expenses set forth in Table 3 for payment of actual municipal legal, consulting and professional expenses through proceeds from the Customer Rate Relief Bonds. Specifically, Atmos Energy shall reimburse TCA, CenterPoint shall reimburse COH and CTM, and TGS shall reimburse SCC.
35. Set forth in this table are the sums of the applicable amounts set forth in Tables 1 and 3 (with the amounts in Table 1 including the amounts in Table 2) above and such sums represent the maximum amounts determined in the Regulatory Asset Determination Order to be recovered by each Applicant through proceeds of the Customer Rate Relief Bonds:

Table 4. Aggregated Regulatory Asset Determination Amounts⁶⁵

⁶³ Regulatory Asset Determination Order, Finding of Fact no. 53.

⁶⁴Regulatory Asset Determination Order, Finding of Fact no. 51.

⁶⁵ Amounts set forth in this table shall be subject to adjustment to reflect actual legal, consulting and professional expenses as described herein.

Applicant	Aggregated Regulatory Asset Determination Amount
Atmos Energy.....	\$ 2,022,536,998
Bluebonnet	\$ 1,962,731
CenterPoint.....	\$ 1,100,662,874
Corix.....	\$ 294,407
EPCOR.....	\$ 11,296,221
SiEnergy	\$ 18,795,497
TGS	\$ 197,375,631
UniGas.....	\$ 32,431,370
Total Aggregated Regulatory Asset Determination Amount	\$ 3,385,355,729 ⁶⁶

36. The Regulatory Asset Determination Order requires that Participating Gas Utilities and Intervenors file updated actual legal, consulting and professional expenses within thirty-five (35) days of issuance of the Financing Order.⁶⁷
37. The Regulatory Asset Determination Order determined that Atmos Energy, CenterPoint and TGS shall be separately reimbursed for payment of actual municipal legal and consulting expenses through Customer Rate Relief Bond proceeds.⁶⁸
38. The Regulatory Asset Determination Order found that Customer Rate Relief Bond financing is the most cost-effective and affordable method of funding regulatory asset reimbursements to Participating Gas Utilities.⁶⁹

⁶⁶ Tex. Util. Code § 104.366(c)(5)(A).

⁶⁷ Regulatory Asset Determination Order, Finding of Fact no. 53.

⁶⁸ Regulatory Asset Determination Order, Finding of Fact no. 52.

⁶⁹ Regulatory Asset Determination Order, Finding of Fact no. 76.

39. The Regulatory Asset Determination Order found that securitization provides tangible and quantifiable benefits to customers greater than would have been achieved absent the issuance of Customer Rate Relief Bonds.⁷⁰

B. Extraordinary Costs and Amounts to Be Securitized

1. Identification and Amounts

The Customer Rate Relief Bonds will finance regulatory assets, including extraordinary costs, financing costs, Bond Administrative Expenses and other costs authorized hereby. Regulatory Assets are defined in Tex. Util. Code § 104.362(16) to include extraordinary costs (i) recorded by Participating Gas Utilities in their books and records in accordance with the uniform system of accounts prescribed for natural gas companies subject to the provisions of the Natural Gas Act (15 U.S.C. § 717 et seq.) by the Federal Energy Regulatory Commission and generally accepted accounting principles; or (ii) classified as a receivable or financial asset under international financial reporting standards under the Commission's authorization in the Notice of Authorization for Regulatory Asset Accounting for Local Distribution Companies Affected by the February 2021 Winter Weather Event issued February 13, 2021 ("Regulatory Asset"). Extraordinary costs are defined in Tex. Util. Code § 104.363 to include the reasonable and necessary costs related to Winter Storm Uri, including carrying costs, placed in a regulatory asset and approved by the Commission in a regulatory asset determination under Tex. Util. Code § 104.365 ("Extraordinary Costs"). "Financing costs" refers to "financing costs" as defined in Tex. Util. Code § 104.362(9), which include, among other items, (i) interest and other amounts payable on Customer Rate Relief Bonds, (ii) any payments required under an Ancillary Agreement or credit agreement (as defined in Tex. Util. Code § 104.362(5)) ("Credit Agreement") related to the Customer Rate Relief Bonds or the funding or replenishment of reserve or other accounts established under the Indenture or other financing document pertaining to the Customer Rate Relief Bonds, (iii) issuance costs or ongoing costs related to supporting, repaying, servicing or refunding the Customer Rate Relief Bonds (including, but not limited to, trustee fees, servicing fees, accounting or auditing fees, printing fees,

⁷⁰ Regulatory Asset Determination Order, Finding of Fact no. 80; Conclusion of Law no. 20.

financial advisor fees or expenses, placement and underwriting fees, legal fees or expenses, consulting fees, issuer fees, capitalized interest, rating agency fees, and Bond Administrative Expenses), and (iv) the costs to the Commission of acquiring professional or consulting services for the purpose of evaluating the Extraordinary Costs. In accordance with Tex. Util. Code § 104.362(3) and as used in this Financing Order, “Bond Administrative Expenses” means all costs and expenses incurred by the Commission, the Authority or the Issuer Entity to evaluate, issue and administer the Customer Rate Relief Bonds, including, but not limited to, fees and expenses of the Central Servicer, any bond administrator, dissemination agent, paying agent, trustee and attorneys, any fees, expenses, costs, damages, judgments, amounts paid in settlement, or awards related to any judicial, administrative, or arbitral proceeding in which the Trustee, the Central Servicer, the Authority or the Issuer Entity is a party, an intervenor, or otherwise engaged (or is obligated to indemnify for, or contribute to, any such amounts paid by another party) arising out of or in connection with the actions contemplated by this Financing Order, and fees for paying other consulting and professional services necessary to ensure compliance with applicable law and the terms of this Financing Order. Financing costs, Bond Administrative Expenses and other costs authorized by the Financing Order relating to the Customer Rate Relief Bonds payable from the proceeds of the Customer Rate Relief Bonds, including amounts for (i) the cost of original issue discount, credit enhancements, reserves established under the Indenture or Ancillary Agreements and other arrangements to enhance marketability of the Customer Rate Relief Bonds as discussed in Ordering Paragraph C.3.; (ii) the cost of the Authority’s, the Issuer Entity’s and the Commission’s financial advisors and legal counsel; and (iii) any costs incurred by the Commission, the Authority or the Issuer Entity if this Financing Order is appealed or if a bond validation proceeding under Tex. Gov’t Code Chapter 1205 is required to issue the Customer Rate Relief Bonds, are referred to herein as “Up-Front Financing Costs”; financing costs and Bond Administrative Expenses payable from revenue collected from the Customer Rate Relief Charges, including, without limitation, related to administering the Customer Rate Relief Bonds, including fees, costs and expenses of the Central Servicer, its advisors, consultants and legal counsel and any advisors or legal counsel hired by the Commission, the Authority or Issuer Entity, related to and incurred during the life of the Customer Rate Relief Bonds, and other costs

authorized by the Financing Order are referred to herein as “Ongoing Financing Costs” and Up-Front Financing Costs and Ongoing Financing Costs are referred to herein, collectively, as “Financing Costs”.

2. Principal Balance to be Securitized

2.1 The Issuer Entity is authorized to issue Customer Rate Relief Bonds in an aggregate amount equal to no more than the Authorized Amount. The Issuance Summary will set forth the estimated Up-Front Financing Costs to be included in the Authorized Amount. To the extent a Participating Gas Utility receives insurance proceeds, governmental grants and other sources of funding that compensate or otherwise reimburse or indemnify the gas utility for extraordinary costs following the issuance of the Regulatory Asset Determination Order, such Participating Gas Utility shall record the amount in a regulatory liability account and that amount shall be reviewed in a future proceeding.⁷¹ If an audit conducted under a valid gas purchase agreement identifies a change of greater than five percent (5.0%) to the total amount of gas supply costs incurred during Winter Storm Uri, the gas utility may record the amount in a regulatory asset or regulatory liability account and that amount shall be reviewed for recovery in a future proceeding.⁷²

2.2 The recovery of the Authorized Amount as provided in this Financing Order is approved herein because ratepayers will receive tangible and quantifiable benefits as a result of the issuance of the Customer Rate Relief Bonds greater than would have been achieved absent such issuance and such recovery is the most cost-effective method of funding regulatory asset reimbursements to be made to Participating Gas Utilities.

⁷¹ Tex. Util. Code § 104.365(i).

⁷² Tex. Util. Code § 104.365(i).

C. Identification of Central Servicer; Collection and Reporting Arrangements

1. Central Servicer

1.1 Pursuant to Tex. Util. Code § 104.362(17) the Commission identifies any of Bank of New York Mellon Corporation, U.S. Bank National Association and Alter Domus (US) LLC (or, in each case, an appropriate affiliate thereof) or such other financial institution or professional services firm possessing the requisite experience and qualifications consistent with achieving the highest possible credit rating on the Customer Rate Relief Bonds, as entities that may be engaged to act as the initial servicer (in such capacity, along with any successor or assignee thereto, the “Central Servicer”) for the Customer Rate Relief Bonds. The Central Servicer will enter into a Servicing Agreement which shall, without limitation, provide for terms substantially consistent with the principles set forth in Exhibit 5 hereto (the “Servicing Agreement”). Exhibit 5 hereto contemplates that the Commission and the Issuer Entity will be parties to the Servicing Agreement as well. The Central Servicer shall be paid a servicing fee as compensation for services rendered and be reimbursed for third-party costs and expenses incurred in performing its services as specified in the Servicing Agreement. No State funds will ever be used to pay or fund the Central Servicer fee or costs or expenses associated with the Servicing Agreement. Fee and expenses payable to the Central Servicer will be paid by the Trustee, on behalf of the Issuer Entity, as a Bond Administrative Expense from the receipt of Customer Rate Relief Charges. Neither the Commission nor the Authority shall ever be liable for any fee or expense incurred by the Central Servicer.

1.2 The initial or otherwise acting Central Servicer may be succeeded as servicer by another entity, identified by the Commission as a potential successor to such Central Servicer, under certain circumstances that will be detailed in the Servicing Agreement. The Central Servicer, among other duties, shall obtain necessary volumetric data and other information from the Participating Gas Utilities pursuant to the Collection and Reporting Arrangements, as well as from the Issuer Entity and the Trustee, required to calculate the periodic True-Up Adjustments, prepare

the True-Up Adjustment Letters, substantially in the form of Exhibit 3 hereto, and deliver the related True-Up Adjustment Letters to the Commission, the Issuer Entity, the Trustee, the Participating Gas Utilities and, as applicable, their Successor Utilities. The Servicing Agreement shall include provisions, as necessary, to achieve the highest possible ratings on the Customer Rate Relief Bonds, as determined by the Issuer Entity. If the Central Servicer defaults on its obligation to file a True Up Adjustment Letter in accordance with the terms of the Servicing Agreement, the Servicing Agreement shall provide for certain remedies to cure such default; such remedies may include an undertaking by the Commission to promptly take all actions necessary to (i) adjust the Customer Rate Relief Charge, on behalf of the Issuing Entity and in accordance with the terms of this Financing Order, to ensure the timely payment of the Customer Rate Relief Bonds, and (ii) identify, and cooperate with the Issuer Entity to appoint, a successor Central Servicer.

- 1.3 Each Participating Gas Utility or its Successor Utilities, as collection agent, shall bill all its sales customers for, and collect, the Customer Rate Relief Charges in accordance with the Collection and Reporting Principles set forth in Exhibit 4 hereto (the “Collection and Reporting Principles”) as required under and to be set forth in the relevant Collection and Reporting Arrangements to be entered into between the Participating Gas Utilities and the Central Servicer. Pursuant to the Servicing Agreement, the Central Servicer will be authorized to, among other things, enter into the Collection and Reporting Arrangements with the Participating Gas Utilities on behalf of the Issuer Entity in furtherance of the collection and remittance of the applicable Customer Rate Relief Charges, the calculation of true-up adjustments and as otherwise determined by the Issuer Entity to be necessary or convenient to execute the transactions authorized by this Financing Order and to obtain the highest possible credit rating for the Customer Rate Relief Bonds pursuant to an ABS Delegation. The Collection and Reporting Arrangements shall also require the provision of other information necessary for the Central Servicer, on behalf of the Issuer Entity, or the Commission to perform any statutory obligations or contractual reporting obligations applicable to the Issuer Entity or

the Commission. The Collection and Reporting Arrangements shall, among other things, require the Trustee, the Commission and the Issuer Entity to be a third-party beneficiary to any rights and interests of the Central Servicer in such Collection and Reporting Arrangements, and provide any additional terms that are supplemental to, or independent of, the Collection and Reporting Principles approved in this Financing Order, if reasonably satisfactory to the applicable contracting parties, including credit enhancement arrangements provided by and reasonably satisfactory to the relevant Participating Gas Utility to support their collection and remittance obligations to ensure that the Customer Rate Relief Bond financing is the most cost-effective method of funding gas utility reimbursements. For the avoidance of doubt, any such credit enhancement arrangement shall be subordinate to such Participating Gas Utility's obligations in respect of Customer Rate Relief Property. The Collection and Reporting Arrangements shall also provide for Participating Gas Utilities to undertake reporting obligations in order to facilitate the Central Servicer's obligation to monitor and verify the remittance of the Customer Rate Relief Charges by each Participating Gas Utility, as collection agent, for payment of the Customer Rate Relief Bonds and other Financing Costs, as described in this Financing Order. In the Collection and Reporting Arrangements, such remittances shall be without any charge, deduction, or surcharge of any kind. The execution and delivery of such Collection and Reporting Arrangements by a Participating Gas Utility shall be a condition precedent to the receipt of proceeds of the Customer Rate Relief Bonds by it. In the event of noncompliance by any Participating Gas Utility with its Collection and Reporting Arrangements and upon written request to the Commission by the Central Servicer, the Issuer Entity or the Trustee, the Commission will act promptly to enforce the obligations of the Participating Gas Utility (or Successor Utility) thereunder.

- 1.4 Any Successor Utility shall assume all obligations under the relevant Collection and Reporting Arrangements in accordance with the terms thereof, provided that substitute Collection and Reporting Arrangements may be entered into if such replacement Collection and Reporting Arrangements are substantially similar to the

Collection and Reporting Arrangements being replaced and substantially consistent with the Collection and Reporting Principles.

- 1.5 **Collection and Reporting Costs.** Each Participating Gas Utility shall book and record in a separate regulatory asset account (in reasonable detail and customary form) its commercially reasonable and necessary costs, (including, but not limited to legal and consulting costs), associated with (i) negotiating and executing the relevant Collection and Reporting Arrangements and (ii) complying with the information disclosure and reporting requirements contemplated in this Financing Order. The amounts booked and recorded by a Participating Gas Utility pursuant to the foregoing sentence shall be referred to as “Collection and Reporting Costs”. For the avoidance of doubt, Collection and Reporting Costs shall be booked and recorded without duplication and any similar or related amounts shall not be recoverable through other methods, including any fees, expenses, reimbursement or like provisions under the Collection and Reporting Arrangements or from proceeds of the Customer Rate Relief Bonds or the Customer Rate Relief Charges. Collection and Reporting Costs shall be reviewed in a subsequent rate proceeding.

D. Proposed Structure of Securitization

1. Issuer Entity

- 1.1 For purposes of this securitization, the Authority has created the “Texas Natural Gas Securitization Finance Corporation” as the Issuer Entity, which is a Texas nonprofit corporation organized under the Business Organization Code, consistent with the provisions of Tex. Gov’t Code § 1232.1072. The Issuer Entity has been formed for the limited purpose of owning the Customer Rate Relief Property, issuing Customer Rate Relief Bonds in one or more series, and in one or more tranches or classes for such series, and performing other activities and participating in financial transactions relating thereto or otherwise authorized by this Financing Order, Tex. Gov’t Code § 1232.1072, or Chapter 104, Subchapter I of the Utilities Code. Tex. Gov’t Code § 1232.1072 also provides that the Issuer Entity shall issue the Customer Rate Relief Bonds in accordance with and subject to the provisions

of Title 9 of the Texas Government Code applicable to the Authority, which includes obtaining the approval of the Texas Bond Review Board (in accordance with its rules) and the Texas Attorney General. The Issuer Entity is not permitted to engage in any other activities and can have no assets other than Customer Rate Relief Property and related assets to support its obligations under the Customer Rate Relief Bonds. Obligations relating to the Customer Rate Relief Bonds will be the Issuer Entity's only significant liabilities. The Issuer Entity must keep its assets and liabilities separate and distinct from those of any other person, including the Authority and any other public authority or instrumentality of the State, and its assets are not permitted to be considered part of any State fund and will be held outside the State treasury. The Issuer Entity is managed by a governing board of three (3) members appointed by the Authority, one or more of which members may be a current or former director of the Authority, unless and until such time as Tex. Gov't Code § 1232.1072 and the Issuer Entity's certificate of formation are amended to provide otherwise. The members of the governing board serve without compensation but are entitled to reimbursement for travel expenses incurred in attending board meetings. The Issuer Entity is established to act on behalf of the State as its duly constituted public authority and instrumentality to issue the Customer Rate Relief Bonds and is authorized under Tex. Gov't Code § 1232.1072(c), to issue the Customer Rate Relief Bonds. The Issuer Entity may exercise the powers granted to the governing body of an issuer with regard to the issuance of obligations and the execution of Credit Agreements under Chapter 1371.

- 1.2 Before the date that is two (2) years and one (1) day after the date that the Issuer Entity no longer has any payment obligation with respect to any Customer Rate Relief Bonds, the Issuer Entity may not wind up or dissolve the Issuer Entity's operations, may not file a voluntary petition under federal bankruptcy law, and neither the governing board of the Issuer Entity nor any public official nor any organization, entity, or other person may authorize the Issuer Entity to be or to become a debtor under federal bankruptcy law during that period. The State has agreed that it will not limit or alter the denial of authority under this section, and

such agreement from the State is made a part of the contractual obligation that is subject to the State pledge made in Tex. Util. Code § 104.374. The restrictions on the activities of the Issuer Entity are imposed to achieve the objective that the Issuer Entity will be bankruptcy-remote.

- 1.3 Upon receipt of this Financing Order in accordance with H.B. 1520, the Authority will direct the Issuer Entity to issue Customer Rate Relief Bonds in one or more series, and in one or more tranches or classes for each such series, in an aggregate amount not to exceed the principal amount approved by this Financing Order and the Issuer Entity will pledge to the Trustee, as collateral for payment of the Customer Rate Relief Bonds, the Customer Rate Relief Property, including the right to receive the Customer Rate Relief Charges as and when collected. The Customer Rate Relief Bonds are limited obligations of the Issuer Entity payable solely from Customer Rate Relief Property and any other money pledged by the Issuer Entity to the payment of the Customer Rate Relief Bonds and are not a debt of the State of Texas, the Commission, the Authority or any gas utility, including any Participating Gas Utility.
- 1.4 In accordance with Chapter 1202 of the Texas Government Code, the Issuer Entity shall submit the Customer Rate Relief Bonds and the record of proceedings to the Texas Attorney General for approval and subsequent registration by the Texas Comptroller of Public Accounts. The Customer Rate Relief Bonds and any contract the proceeds of which are pledged to the payment of the Customer Rate Relief Bonds are valid and incontestable in a court or other forum and are binding obligations for all purposes according to their terms after the Customer Rate Relief Bonds are approved by the Texas Attorney General and registered by the Texas Comptroller of Public Accounts.
- 1.5 The Customer Rate Relief Property created under this Financing Order will be vested *ab initio* in the Issuer Entity.
- 1.6 The use and proposed structure of the Issuer Entity and the limitations related to its organization and management are consistent with the requirements of H.B. 1520.

2. Terms and Parameters of Customer Rate Relief Bonds; Maturity

- 2.1 To attract a broad range of investors and achieve the lowest cost of capital, the Customer Rate Relief Bonds may be issued in one or more series, and each series may be divided into several tranches or classes. Each series and each tranche or class within a series may have a different scheduled final payment date and legal final maturity date; provided, however, the maximum scheduled final maturity date of any series will not exceed thirty (30) years from the date of issuance of the Customer Rate Relief Bonds.
- 2.2 At least twenty one (21) days prior to the marketing of the Customer Rate Relief Bonds (unless a shorter period is acceptable to the Designated Representative in its sole discretion), the Issuer Entity shall, upon written notice to the Designated Representative, request that the Designated Representative provide a written determination of (i) the target recovery period (i.e., being a twelve month period during which the final scheduled maturity of the last maturing series or tranche of Customer Rate Relief Bonds must occur) and (ii) the amortization methodology to be used to structure the Customer Rate Relief Bonds (the “Target Determination”). As part of such request, the Issuer Entity shall specify the date by which the Target Determination is requested and provide to the Designated Representative such market and financial information, in its, the Authority’s, the lead underwriter’s or structuring agent’s possession, that is reasonably necessary for the Designated Representative to make the Target Determination. The Designated Representative is authorized to request such additional market or financial information in the Issuer Entity’s, the Authority’s, the lead underwriter’s or structuring agent’s possession, that it reasonably believes is necessary to make the Target Determination. The Designated Representative is hereby authorized to provide the Target Determination in writing to the Issuer Entity by the date requested by the Issuer Entity; provided, however, that; the Designated Representative shall have at least fourteen (14) days to review the market and financial information provided by the Issuer Entity (unless a shorter period is acceptable to the Designated Representative in its sole discretion) and the date by which the Designated Representative is

required to provide the Target Determination shall be extended as necessary to allow for such fourteen (14) day review period. Subject to Findings of Fact, Sections IV.D.2.1 and 2.2 and Section IV.D.3, the scheduled final maturity date, as well as the other final terms of the Customer Rate Relief Bonds will be determined at the time of pricing of the Customer Rate Relief Bonds by the Issuer Entity consistent with parameters provided to the Issuer Entity by the Authority in accordance with the Authority Bond Standards and in consultation with the Designated Representative, and shall be set forth in the Indenture or other bond documents. For the avoidance of doubt, the scheduled or legal final maturity date for any tranche or class of bonds may be later than the Target Determination based on rating agency and/or market considerations, as determined by the Issuer Entity and within the parameters provided to the Issuer Entity by the Authority in accordance with the Authority Bond Standards. The Issuer Entity shall not issue the Customer Rate Relief Bonds later than the one hundred and eightieth (180th) day after the date of this Financing Order, except that the issuance date may occur after the one hundred and eightieth (180th) day in accordance with Tex. Util. Code § 104.366(n) if necessary based on bond market conditions, the receipt of necessary approvals, the timely receipt of necessary financial disclosure information from each Participating Gas Utility, described in Findings of Fact, Section IV.D.12, titled “Designated Representative”.

- 2.3 Subject to Findings of Fact, Sections IV.D.2.1 and 2.2 and IV.D.3, the Authority will determine the methods of sale, types of bonds, bond forms and applicable terms, interest rates, principal amortization, amount of reserves or capitalized interest, and other terms of the Customer Rate Relief Bonds, including maturities and call provisions, which, in the Authority’s judgment, best achieve the economic goals of this Financing Order and effect the financing at the lowest practicable cost, in accordance with its statutory obligations and duties, including provisions of Title 9 of the Texas Government Code applicable to the Authority with respect to the issuance of the Customer Rate Relief Bonds and as provided in Tex. Util. Code §104.366(f)(2) (collectively, the “Authority Bond Standards”).

- 2.4 The Issuer Entity is authorized to enter into the Indenture and Ancillary Agreements in connection with the issuance of Customer Rate Relief Bonds and any arrangements related thereto permitted under this Financing Order, including in connection with any credit enhancements approved under this Financing Order. Any amount owed by the Issuer Entity under the Indenture or any Ancillary Agreement is payable from and secured by a pledge and interest in the Customer Rate Relief Property to the extent provided in such agreements.
- 2.5 The Central Servicer, the Participating Gas Utilities and any Successor Utilities shall provide to the Issuer Entity and the Authority any information that the Authority or the Issuer Entity deems reasonably necessary to facilitate the pricing and issuance of the Customer Rate Relief Bonds. The Participating Gas Utilities and the Successor Utilities shall comply with such requests on a reasonably prompt basis and provide such information in the form requested by the Authority or the Issuer Entity.
- 2.6 The Commission finds that the proposed structure, as described in and subject to the terms of this Financing Order, is in the public interest and should be used. The final and definitive terms of the Customer Rate Relief Bonds will be summarized in the Issuance Summary and evidenced by the bond purchase agreement or underwriting agreement, as applicable, the Indenture and related bond documents executed by the Issuer Entity. The Commission is relying on the Authority acting in a manner consistent with the Authority Bond Standards in connection with making determinations and other decisions with respect to the Customer Rate Relief Bonds and other matters contemplated by this Financing Order.

3. Maximum Interest Rate

The weighted average interest rate for the Customer Rate Relief Bonds (based on scheduled maturities) may not exceed five percent (5.0%); provided that the Designated Representative shall be authorized, on behalf of the Commission, to adjust such maximum interest rate subsequent to the date hereof, in consultation with the Issuer Entity pursuant to an ABS Delegation. In connection with the preceding sentence, the Designated

Representative shall be authorized to reasonably request all information in the Issuer Entity's, the Authority's, the lead underwriter's or structuring agent's possession that the Designated Representative deems reasonably necessary in order to adjust such maximum rate. Any such adjustment in maximum interest rate by the Designated Representative, on behalf of the Commission, shall be confirmed in writing to the Authority prior to pricing of the Customer Rate Relief Bonds. Subject to Findings of Fact, Section IV.D.3, the interest rate will be determined at the time of pricing of the Customer Rate Relief Bonds by the Issuer Entity within parameters established by the Authority in accordance with the Authority Bond Standards. In approving the interest rate, the Issuer Entity shall consider market conditions, any recommendations of the Designated Representative and information from advisors of the Issuer Entity and, if applicable, of the Designated Representative, and the structuring, marketing, and pricing process of the Customer Rate Relief Bonds in addition to other factors it deems relevant in its commercially reasonable discretion pursuant to an ABS Delegation.

4. Credit Enhancement

4.1 As permitted under H.B. 1520, the Commission authorizes the use of Credit Agreements, Ancillary Agreements and additional forms of credit enhancement (including reserve accounts) by the Issuer Entity to promote the credit quality and marketability of the Customer Rate Relief Bonds if such enhancements are necessary to obtain desired ratings from the rating agencies or based on other market considerations as determined by the Issuer Entity consistent with parameters provided to the Issuer Entity by the Authority in accordance with the Authority Bond Standards. In addition to other reserves, the Issuer Entity is statutorily permitted to establish reserve funds in the form of a debt service reserve as an additional form of credit enhancement to promote the credit quality and marketability of the Customer Rate Relief Bonds. Any payments required in connection with such reserve account, including the initial funding, are considered Financing Costs which must be included in the principal amount of the Customer Rate Relief Bonds under Tex. Util. Code § 104.366(e)(1) and which shall be included in Customer Rate Relief Charges under Tex. Util. Code § 104.366(c)(6).

4.2 To the extent additional forms of credit enhancement, including letters of credit, surety bonds, guarantees, hedging arrangements, or liquidity support arrangements and other arrangements contemplated by Tex. Util. Code § 104.366(g) would (i) be expected by the Issuer Entity to result in lower Customer Rate Relief Charges and (ii) not expose the Customer Rate Relief Bond financing to higher risks and greater uncertainty about future costs, the use of such form of credit enhancement shall be permitted in order to receive the highest possible credit rating on the Customer Rate Relief Bonds or lowest all-in-costs. The Issuer Entity is authorized to enter into Credit Agreements or Ancillary Agreements in connection with this Financing Order.

5. Customer Rate Relief Property

- 5.1 Under Tex. Util. Code § 104.364(c), the Commission has exclusive original jurisdiction to issue this Financing Order and authorize the creation of Customer Rate Relief Property, which pursuant to Tex. Util. Code § 104.367(d) will vest *ab initio* in the Issuer Entity and not constitute property of the Commission or any gas utility. In accordance with Tex. Util. Code § 104.366(c)(7), the Commission authorizes the creation of the Customer Rate Relief Property in favor of the Issuer Entity and the pledge of the Customer Rate Relief Property by the Issuer Entity to the payment of the Customer Rate Relief Bonds.
- 5.2 Under Tex. Util. Code § 104.367(c), the rights and interests of the Issuer Entity or successor under a financing order, including the right to receive the Customer Rate Relief Charges authorized in the financing order, are only contract rights until they are first pledged in connection with the issuance of Customer Rate Relief Bonds, at which time they will become Customer Rate Relief Property.
- 5.3 Customer Rate Relief Property and all other collateral is expected to be held and administered by the Trustee pursuant to the Indenture and related ancillary documentation in order to secure the Customer Rate Relief Bonds authorized by this Financing Order.

- 5.4 As provided in Tex. Util. Code § 104.367(d), the Customer Rate Relief Property created under this Financing Order will be vested *ab initio* in the Issuer Entity and Customer Rate Relief Property will constitute a present property right for purposes of contracts concerning the sale or pledge of property, even though the imposition and collection of Customer Rate Relief Charges depends on further acts of the gas utilities or others that have not yet occurred.
- 5.5 Pursuant to H.B. 1520, the interest of the Issuer Entity or any pledgee in the Customer Rate Relief Property, including revenues and collections arising from the Customer Rate Relief Charges, is not subject to setoff, counterclaim, surcharge or defense by any gas utility or any other person or in connection with a bankruptcy of a Participating Gas Utility, the Authority, the Issuer Entity or any other entity.

6. Security for Bonds

- 6.1 The payment of principal and interest on the Customer Rate Relief Bonds and other Ongoing Financing Costs is to be secured by the Customer Rate Relief Property created by this Financing Order and by certain other related collateral to be pledged by the Issuer Entity. The Customer Rate Relief Bonds will be issued pursuant to the Indenture and administered by the Trustee. The Indenture will include provisions for the establishment of a collection account for the Customer Rate Relief Bonds and subaccounts as trust accounts to be held by the Trustee as collateral for the collection and administration of the Customer Rate Relief Charges, and payment or funding of the principal and interest on the Customer Rate Relief Bonds and other Ongoing Financing Costs, in full and on a timely basis. As specified in the Indenture, the collection account will include the general subaccount, any operating reserve subaccount, a debt service reserve subaccount, an excess funds subaccount, and any other subaccounts, as determined necessary or desirable by the Issuer Entity. Notwithstanding anything herein to the contrary, the final flow of funds among the various accounts and subaccounts shall be determined by the terms of the Indenture.

- 6.2 Customer Rate Relief Charge remittances that Participating Gas Utilities must remit pursuant to the Financing Order and the Collection and Reporting Arrangements, will be deposited with the Trustee for the account of the Issuer Entity into the general subaccount. The Trustee will allocate or use all amounts, including investment earnings, in this subaccount on a periodic basis, in accordance with the terms of the Indenture, to pay principal of and interest on the Customer Rate Relief Bonds and other Ongoing Financing Costs. It is expected that the funds in the general subaccount will be invested by the Trustee in short-term high-quality investments subject to other criteria to be agreed and that is customary and/or required for transactions of this type by Texas governmental issuers, and such funds (including, to the extent necessary, investment earnings) will be applied by the Trustee in accordance with the terms of the Indenture.
- 6.3 When the Customer Rate Relief Bonds are issued, part of the proceeds will be deposited into the various accounts or subaccounts established under the Indenture, including a debt service reserve subaccount. The amount of such proceeds to be deposited into the debt service reserve subaccount is expected (but not required) to be not less than five tenths of a percent (0.50%) of the original principal amount of the Customer Rate Relief Bonds, although the actual amount will depend on tax and rating agency requirements. The debt service reserve subaccount will be utilized as collateral to ensure timely payment of principal and interest on the Customer Rate Relief Bonds and all other components of the Periodic Payment Requirement. Any funds drawn from the debt service reserve subaccount to pay these amounts due to a shortfall in the Customer Rate Relief Charge remittances will be replenished through future Customer Rate Relief Charge remittances or the excess funds subaccount. It is expected that the funds in this subaccount will be invested by the Trustee in short-term high-quality investments subject to other criteria to be agreed in the Indenture that is customary and/or required for transactions of this type by Texas government issuers, and such funds (including investment earnings) will be used by the Trustee to pay principal and interest on the Customer Rate Relief Bonds and all other components of the Periodic Payment Requirement, in accordance with the final terms of the Indenture.

6.4 Upon payment in full of the principal amount of all Customer Rate Relief Bonds and interest thereon and the discharge of all other obligations that may be paid by use of Customer Rate Relief Charges, the Trustee shall provide written notice to the Commission, the Issuer Entity, the Central Servicer and the relevant Participating Gas Utilities and relevant Successor Utilities (collectively, the “Remaining Utilities”) (as directed by the Central Servicer) of all remaining funds held by the Trustee, including any investment earnings thereon, under the Indenture. Within fifteen (15) business days of such notice being issued, all of the Remaining Utilities shall be required to deliver a joint allocation letter (the “Allocation Letter”) to the Trustee, the Issuer Entity and the Commission proposing how such amounts are to be allocated among the Remaining Utilities with sufficient details for the Trustee to distribute such amounts. The Allocation Letter shall be prepared in consultation with the Commission. The Trustee shall disburse the relevant amounts in accordance with the Allocation Letter unless the Commission issues a written objection to the Remaining Utilities, the Issuer Entity and the Trustee before the date occurring forty-five (45) days (“Allocation Letter Objection Date”) after delivery of the Allocation Letter. The relevant amounts shall not be disbursed prior to the Allocation Letter Objection Date unless the Commission notifies the Issuer Entity and the Trustee in writing otherwise and, in all cases, subject to the delivery of the Allocation Letter. If the Allocation Letter is not timely received from all Remaining Utilities, the relevant amounts shall be distributed to each Remaining Utility according to each Remaining Utility’s average normalized sales volumes for the prior five (5) calendar years as a percentage of the average total normalized sales volumes for all Remaining Utilities (which percentage shall be calculated by the Central Servicer and provided to the Trustee in writing) or in such other manner determined by the Commission in consultation with the Remaining Utilities and provided to the Trustee in writing. The provisions of this paragraph are referred to herein as the “Remaining Balances Provisions”. Amounts received by a Participating Gas Utility pursuant to the Remaining Balances Provisions shall be recorded by such Participating Gas Utility in a regulatory liability account and that amount shall be reviewed in a future proceeding consistent

with Tex. Util. Code § 104.372(c). For the avoidance of doubt, total normalized sales volumes, as used in this paragraph, shall refer to actual rather than projected figures.

6.5 The excess funds subaccount will hold any Customer Rate Relief Charge remittances and investment earnings on the collection account in excess of the amounts needed to pay principal and interest and other amounts due on the Customer Rate Relief Bonds, in accordance with the terms thereof, and to pay Ongoing Financing Costs (including, but not limited to, replenishing any specified reserve subaccounts). Any balance in or allocated to the excess funds subaccount on a true-up adjustment date will be subtracted from the Periodic Payment Requirement for purposes of the true-up adjustment. It is expected that the funds in this subaccount will be invested by the Trustee in short-term high-quality investments and subject to other criteria to be agreed in the Indenture that is customary and/or required for transactions of this type by Texas government issuers, and such funds (including investment earnings thereon) will be used by the Trustee in accordance with the terms of the Indenture.

6.6 Other credit enhancements in the form of subaccounts may be utilized for the securitization transaction as more fully described in Findings of Fact, Section IV.D.4.

7. Customer Rate Relief Charges – Imposition of Uniform Monthly Volumetric Surcharge and Collection and Nonbypassability

7.1 This Financing Order imposes on all existing and future customers receiving service from Participating Gas Utilities or their Successor Utilities, Customer Rate Relief Charges in an amount sufficient to provide for the timely recovery of payment obligations with respect to the Customer Rate Relief Bonds (including payment of principal and interest on the Customer Rate Relief Bonds and other Ongoing Financing Costs, all as authorized by this Financing Order).

- 7.2 The Customer Rate Relief Charges will be collected from the sales customers of Participating Gas Utilities through uniform monthly volumetric charges to be paid by sales customers as a component of the Participating Gas Utility's gas cost.
- 7.3 Participating Gas Utilities shall file with the Commission (i) updated cost of gas rate schedules that include the Customer Rate Relief Charge as a component of the Participating Gas Utility's gas cost and (ii) the draft Customer Rate Relief Rate Schedule in substantially the same form as Exhibit 1 hereto, in each case, no later than forty-five (45) days following the issuance of this Financing Order.
- 7.4 The Customer Rate Relief Charges will be collected in full by each Participating Gas Utility or its Successor Utilities, or a collection agent, on its behalf as provided in this Financing Order as contemplated by Tex. Util. Code § 104.362(7)(B).
- 7.5 The Customer Rate Relief Charges will be nonbypassable charges, payable by existing and future customers receiving service from a Participating Gas Utility or its Successor Utilities, will not be subject to offset by any credit, and any collections from customers who make partial payments will be applied first to any outstanding Customer Rate Relief Charges prior to the satisfaction of any other charges included on such customers' bills. The obligations of Successor Utilities hereunder are binding by operation of law. Each Participating Gas Utility (or its Successor Utilities) will continue to bill all sales customers for and collect the Customer Rate Relief Charges from such customers until all Customer Rate Relief Bonds and Ongoing Financing Costs are paid in full.
- 7.6 For the benefit of the Authority, the Issuer Entity, the holders of the Customer Rate Relief Bonds and the other financing parties, including the Trustee, any collateral agent, and any party to Ancillary Agreements, the Commission guarantees that the Commission will take all actions in its powers to enforce the provisions of this Financing Order to ensure that Customer Rate Relief Charge revenues are sufficient to pay on a timely basis scheduled principal and interest on the Customer Rate Relief Bonds and all Ongoing Financing Costs.

- 7.7 Each of the Participating Utilities shall comply with and perform the Collection and Reporting Principles with respect to the billing, collection and remittance of the Customer Rate Relief Charges. In the event of noncompliance by any Participating Gas Utility with its Collection and Reporting Arrangements and upon written request to the Commission by the Central Servicer, the Issuer Entity or the Trustee, the Commission will act promptly to enforce the obligations of the Participating Gas Utility (or Successor Utility) thereunder for the benefit of the Authority, the Issuer Entity, the holders of the Customer Rate Relief Bonds and the other financing parties, including the Trustee, any collateral agent and any party to Ancillary Agreements.
- 7.8 In accordance with Tex. Gov't Code § 1232.1072(j), by the adoption of this Financing Order and any further action to be taken by the Commission contemplated hereunder, the Commission has ensured that Customer Rate Relief Charges are imposed, collected, and enforced in an amount sufficient to pay on a timely basis all bond obligations (as defined in Tex. Util. Code § 104.362(4)) and Financing Costs associated with any issuance of Customer Rate Relief Bonds.

8. General Provisions

- 8.1 The collection account and the subaccounts described in Findings of Fact, Section IV.D.6, titled "Security for Bonds" are intended to provide for full and timely payment of principal and interest on the Customer Rate Relief Bonds and all other components of the Periodic Payment Requirement. If the amount of Customer Rate Relief Charges remitted to the general subaccount is insufficient to make all payments of principal and interest on the Customer Rate Relief Bonds and to make payment on other components of the Periodic Payment Requirement, the excess funds subaccount and the debt service reserve subaccount will be drawn down, in that order, to make those payments. Any deficiency in the debt service reserve subaccount due to such withdrawals must be replenished on a periodic basis through True-Up Adjustments.

9. True-Up System

- 9.1 Pursuant to Tex. Util. Code § 104.370, the Central Servicer will make scheduled adjustments, at least annually, as set forth in the Servicing Agreement (“Scheduled True-Up Adjustments”) to the Customer Rate Relief Charges to (i) correct any undercollection or overcollection of Customer Rate Relief Charges; and (ii) ensure the billing of Customer Rate Relief Charges, across all Participating Gas Utilities, necessary to generate the collection of amounts sufficient to timely provide funds to pay all scheduled payments of principal and interest and other Ongoing Financing Costs during the period for which such adjusted Customer Rate Relief Charges are to be in effect (such amounts are referred to as the “Periodic Payment Requirement”).)
- 9.2 The amounts necessary to be billed to collect such Periodic Payment Requirement during such period to account for uncollectible amounts, delinquencies, the timing of collections or other causes of a shortfall or surplus, are referred to as the “Periodic Billing Requirement”. Each of Atmos Energy Corporation, CenterPoint Energy Resources Corp., Texas Gas Service Company, and any Participating Gas Utility or Successor Utility whose Normalized Sales Volumes exceed two percent (2.0%) of the total aggregate Normalized Sales Volumes among all Participating Gas Utilities (each, a “Large Participating Gas Utility”) will provide information required by the Central Servicer to calculate such Periodic Billing Requirements. Any calculation performed to determine if a Participating Gas Utility is a Large Participating Gas Utility shall be performed on the basis of the most recently reported Normalized Sales Volumes. Until these assumptions are otherwise revised by the Commission based upon information provided by such Participating Gas Utilities, pursuant to this Financing Order, the calculation of the Customer Rate Relief Charges will assume that all billed amounts, net of a one percent (1.0%) reduction in such amounts to reflect uncollectible amounts billed, will be received thirty (30) days after the billing date.
- 9.3 True-up filings will be based on the cumulative differences, regardless of the reason, between the Periodic Payment Requirement and the amount of Customer Rate Relief Charge remittances to the Trustee. True-up procedures are necessary

to ensure full recovery of amounts sufficient to meet the Periodic Payment Requirements over the expected life of the Customer Rate Relief Bonds. In order to ensure adequate Customer Rate Relief Charge revenues to fund the Periodic Payment Requirement and to avoid large overcollections and undercollections over time, the Central Servicer will reconcile the Customer Rate Relief Charges using Normalized Sales Volumes, defined below, and estimates of Ongoing Financing Costs. The calculation of the Customer Rate Relief Charges will also initially reflect an uncollectible factor of one percent (1.0%) and be based upon the Normalized Sales Volumes of the Large Participating Gas Utilities. “Normalized Sales Volumes” is defined as set forth in Exhibit 1 hereto. To the extent actual collections of a Large Participating Gas Utility vary materially from the uncollectible factor then in effect for a number of billing cycles to be determined, such Large Participating Gas Utility shall notify the Commission and Central Servicer in writing pursuant to the relevant Collection and Reporting Arrangement and the Commission shall consequently review any relevant information provided by such Large Participating Gas Utility and notify the Central Servicer if any modifications to the uncollectible factor are appropriate in order to ensure the Customer Rate Relief Charge is set at a level sufficient to ensure timely payment of debt service on the Customer Rate Relief Bonds and all Ongoing Financing Costs. Each Participating Gas Utility shall report Normalized Sales Volumes for the relevant twelve (12) month period no later than June 1 of each year to the Commission.

- 9.4 Scheduled True-Up Adjustments and Interim True-Up Adjustments (as described in Paragraph 10 below) shall be calculated based upon the Description of Cash Flow Model, attached as Exhibit 2 hereto, and implemented as provided in this Financing Order, including as set forth in the Customer Rate Relief Charge Schedule, attached as Exhibit 1 hereto, and the Form of True-Up Adjustment Letter, attached as Exhibit 3 hereto.
- 9.5 The Central Servicer is authorized to make Scheduled True-Up Adjustments and Interim True-Up Adjustments, on behalf of the Issuer Entity, in the manner

consistent with Paragraph 9.4 above, and as reflected and provided in the Servicing Agreement.

- 9.6 If the actual Up-Front Financing Costs are less than the amounts set forth in the Issuance Summary, the Periodic Billing Requirement for the first (1st) Scheduled True-Up Adjustment shall be reduced by the amount of such unused funds (together with interest, if any, earned on the investment of such funds) and such unused funds (together with such interest) shall be available for payment of debt service on the bond payment date next succeeding such true-up adjustment.

10. Interim True-Up

- 10.1 In addition to Scheduled True-Up Adjustments, true-up adjustments shall be made by the Central Servicer, in accordance with the terms of the Servicing Agreement, more frequently at any time during the term of the Customer Rate Relief Bonds to correct any undercollection or overcollection, in order to ensure timely payment of Customer Rate Relief Bonds based on rating agency and bondholder considerations (“Interim True-Up Adjustments,” and together with Scheduled True-Up Adjustments, “True-Up Adjustments”). Such adjustments may be mandatory or made in the discretion of the Central Servicer, as required by the Servicing Agreement, but not more frequently than quarterly.
- 10.2 Each Large Participating Gas Utility shall, upon the request of the Central Servicer, provide the Commission and the Central Servicer updated Normalized Sales Volumes for the succeeding twelve (12) month period no later than the fifteenth (15th) day following such request to allow the Central Servicer to make Interim True-Up Adjustments. Each Large Participating Gas Utility shall have the right to provide the foregoing information to the Central Servicer on a confidential basis if reasonably necessary to ensure compliance with applicable securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed),

it being understood that certain information provided by the Large Participating Gas Utilities shall be disclosed pursuant to Ordering Paragraph C.9.

10.3 In the event an Interim True-Up Adjustment is made, the True-Up Adjustment Letter should be delivered to the Commission, the Authority, the Issuer Entity, the Participating Gas Utilities and, as applicable, their Successor Utilities and the Trustee on the fifteenth (15th) day of the current month for implementation in accordance with the Collection and Reporting Arrangements.

10.4 If the actual Up-Front Financing Costs are more than the amounts set forth in Issuance Summary, such shortfall may be recovered through an interim true-up adjustment.

11. Issuance Summary

11.1 Because the actual structure and pricing of the Customer Rate Relief Bonds and the precise amounts to be securitized are not known at the time this Financing Order is issued, following determination of the final terms of the Customer Rate Relief Bonds, the Authority will deliver to and file with the Commission no later than five (5) business days after the Closing Date, an issuance summary report (the “Issuance Summary”). The Issuance Summary will set forth the final terms of the Customer Rate Relief Bonds in satisfaction of the Authority’s initial statutory reporting obligation⁷³ and in order to assist the Commission in satisfying its statutory reporting obligations.⁷⁴ The Issuance Summary shall include a description of each series of Customer Rate Relief Bonds, total principal amount, Up-Front Financing Costs, estimated Ongoing Financing Costs, maturity, credit enhancements, weighted average life, call provisions and amortization schedules. The Authority will also provide copies of all publicly available bond issuance documents, the Indenture and any related bond documents and attach such copies to the Issuance Summary. The Issuance Summary will include the Authority’s best estimate of

⁷³ Tex. Gov’t Code § 1232.1072(m); Tex. Util. Code §§ 104.377(b).

⁷⁴ Tex. Util. Code §§ 104.366(q).

Up-Front Financing Costs and such estimate will be included in the principal amount securitized. The Designated Representative or a designee thereof is authorized to report the final amount of Up-Front Financing Costs attributable to the Commission's expenses in writing to the Authority within forty-five (45) days of the Closing Date. Within sixty (60) days of issuance of the Closing Date, the Authority shall submit to the Commission a final report of the total Up-Front Financing Costs.⁷⁵

12. Designated Representative

12.1 In order to ensure compliance with applicable sections of the Utilities Code and this Financing Order, the Commission finds that it is reasonable and appropriate to appoint the executive director or other officer or employee thereof as a Designated Representative who shall work collaboratively with the Authority and the Issuer Entity during the Issuance Process and thereafter. The Designated Representative will act in a consultative role and provide input and advice to the Authority and/or the Issuer Entity, including providing the Target Determination described under Findings of Fact, Section IV.D.2.2, adjusting the authorized interest rate described under Findings of Fact, Section IV.D.3 and determining the bond payment periods described in Exhibit 2 hereto. It is reasonable and appropriate that decisions regarding the structuring, marketing and pricing of the Customer Rate Relief Bonds will be made by the Issuer Entity consistent with parameters provided to the Issuer Entity by the Authority in accordance with the Authority Bond Standards and in accordance with applicable provisions of H.B. 1520 and this Financing Order, as the Issuer Entity is a public authority created by the Texas Legislature to cost-effectively issue bonds on behalf of Texas state agencies and the Authority is subject to the Authority Bond Standards in carrying out its obligations contemplated by the Financing Order. The Designated Representative may also specify any successor officer or employee of the Commission to serve in the role as Designated Representative as well as designate other staff, legal counsel,

⁷⁵ Id.

financial advisors and other consultants, to (i) assist the Commission during the Issuance Process for the Customer Rate Relief Bonds and (ii) act as its designee following the Closing Date. Any costs incurred by or on behalf of the Commission and/or its Designated Representative in connection with the Customer Rate Relief Bonds, including those of its legal counsel, financial advisors and other consultants, shall be treated as Financing Costs.

- 12.2 The Authority and the Issuer Entity may consult with the Designated Representative with respect to all plans and decisions relating to the structuring, marketing, and pricing of the Customer Rate Relief Bonds. It is reasonable for the Authority to provide the Designated Representative with timely information upon request to allow the Designated Representative and any other staff, legal counsel, financial advisors and other consultants designated by the Commission to be informed in advance, as practicable, regarding all aspects of the structuring, marketing, pricing and issuance of the Customer Rate Relief Bonds. It is reasonable for the Designated Representative, if requested by the Authority or the Issuer Entity, to be present during communications with underwriters, rating agencies and investors. The Issuer Entity shall have the right to request that the Designated Representative review information prepared for the benefit of the rating agencies or for use in marketing the Customer Rate Relief Bonds and it is expected that the Designated Representative shall provide any feedback on a reasonable basis.
- 12.3 The Designated Representative shall have the right during the Issuance Process to review and comment on any contract to memorialize a Collection and Reporting Arrangement, and the Indenture, in each case, prior to the finalization of such documents.
- 12.4 Each of the Designated Representative and the Commission Staff shall have the right to request all information from the Authority, the Issuer Entity, the Central Servicer, the Participating Gas Utilities and the Successor Utilities that the Designated Representative deems reasonably necessary to comply with the Financing Order or the Commission's statutory reporting obligations in relation to

the Customer Rate Relief Bonds, including pursuant to Tex. Util. Code § 104.366(q); provided, however, the Issuance Summary is expected to provide the Commission with the information that will be required from the Authority and the Issuer Entity in order for the Commission to comply with Tex. Util. Code § 104.366(q). The Authority, the Issuer Entity, the Central Servicer, the Participating Gas Utilities and the Successor Utilities shall be required to comply with such requests on a reasonably prompt basis and provide such information in the form requested by the Designated Representative or the Commission Staff; provided, however, the Issuance Summary is expected to be the form by which the Authority and the Issuer Entity will provide such information in order for the Commission to comply with Tex. Util. Code § 104.366(q).

- 12.5 During the Issuance Process, subject to Ordering Paragraphs C.4, C.5 and C.7, the Commission acknowledges that the role of the Designated Representative shall be consultative, that the Issuer Entity and the Authority will have their own financial consultants, and that the final terms of the Customer Rate Relief Bonds will be conclusively determined by the Issuer Entity consistent with the terms of this Financing Order and pursuant to an ABS Delegation.

13. No Recourse to the State

- 13.1 Pursuant to Tex. Util. Code § 104.374(a), the Customer Rate Relief Bonds and any Ancillary Agreement or Credit Agreements do not constitute a debt or pledge of the full faith and credit of the State of Texas or any state agency or political subdivision thereof. The Customer Rate Relief Bonds and any Ancillary Agreements or related Credit Agreements are payable solely from Customer Rate Relief Property as provided in Chapter 104, Subchapter I of the Utilities Code. In addition, pursuant to Tex. Util. Code § 104.375(a), the sale or purchase of or revenue derived from services performed in the issuance or transfer of the Customer Rate Relief Bonds is exempt from taxation by the State or any political subdivision of the State.

13.2 Notwithstanding the foregoing, as required under Tex. Util. Code § 104.374, the documentation relating to the Customer Rate Relief Bonds shall include a pledge by the State, the Commission and the Authority for the benefit of the holders of the Customer Rate Relief Bonds and the Participating Gas Utilities that the State will not take or permit any action that would impair the value of Customer Rate Relief Property or, except as permitted by Tex. Util. Code § 104.370, reduce, alter, or impair the Customer Rate Relief Charges to be imposed, collected, and remitted to such holders until the principal, interest and premium, and contracts to be performed in connection with the Customer Rate Relief Bonds and Financing Costs have been paid and performed in full.

13.3 Pursuant to Tex. Gov't Code §1232.1072(p): (i) assets of the Issuer Entity shall not be considered part of any State fund and must be held outside the State treasury; and (ii) the Issuer Entity must be self-funded from Customer Rate Relief Property and established in accordance with Chapter 104, Subchapter I of the Utilities Code; and (iii) a state agency may provide money appropriated for the purpose to the Issuer Entity to provide for initial operational expenses of the Issuer Entity.

14. Authorization of Recovery of Tax Obligations of Participating Gas Utilities

14.1 This Financing Order authorizes the recovery of any tax obligation of the Participating Gas Utilities arising or resulting from (i) receipt of Customer Rate Relief Bond proceeds; or (ii) collection or remittance of Customer Rate Relief Charges through the gas utilities' gas cost recovery mechanism or other means that the Commission determines reasonable, pursuant to Tex. Util. Code § 104.376.

15. Reporting Requirements for Authority

15.1 The Authority shall report to the Commission the amount of the Customer Rate Relief Bonds and the estimated amount of annual Bond Administrative Expenses pursuant to Tex. Util. Code § 104.373(b). The Authority shall also make periodic reports to the Commission and the public, and provide any other information or documentation requested by the Commission, regarding the Customer Rate Relief Bonds if requested by the Commission from time to time pursuant to Tex. Gov't

Code § 1232.1072(m). Each of the Indenture, the Collection and Reporting Arrangements and any other relevant ancillary documentation shall provide that the Commission shall receive a copy of any notice of defaults or events of default under such document and any other material notices delivered under such document in order for the Commission to comply with its statutory obligations.

16. Reporting Obligations of Participating Gas Utilities

16.1 The Participating Gas Utilities shall provide all information requested by the Issuer Entity, through its counsel, or the lead underwriter, through its counsel, deemed reasonably necessary by the Issuer Entity to issue the Customer Rate Relief Bonds (including, but not limited to, information prepared for the benefit of rating agencies, information prepared for use in marketing the Customer Rate Relief Bonds to investors or information deemed necessary by the Issuer Entity to satisfy state and federal securities laws) which includes, at a minimum, volumetric data, projected collections and other related information. It is acknowledged that any information so provided to the Issuer Entity for use in connection with the issuance of the Customer Rate Relief Bonds (i) must not contain any untrue statement of a material fact or (ii) omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading. The form of verifications to be made in connection with the foregoing sentence will be determined by the Participating Gas Utilities, the Issuer Entity, and the lead underwriter, through their respective representatives and/or counsel, and provided to the Issuer Entity, the lead underwriter and any other financing party as determined by such entities prior to the marketing of the Customer Rate Relief Bonds.

16.2 In order to ensure full and complete compliance with applicable United States Securities and Exchange Commission rules and regulations, including Rule 15c2-12, Participating Gas Utilities shall negotiate in good faith with the Issuer Entity, to enter into agreements (binding against such Participating Gas Utility and any Successor Utility) deemed necessary for the underwriters to purchase the Customer Rate Relief Bonds pursuant to federal securities laws and regulations and such

agreements shall include customary representations and assurances as to any information provided thereunder.

16.3 Participating Gas Utilities shall be required to provide all information in the form requested by the Commission that the Commission deems reasonably necessary to comply with the Financing Order or the Commission's statutory reporting obligations in relation to the Customer Rate Relief Bonds, including pursuant to Tex. Util. Code § 104.366(q). Each Large Participating Gas Utility shall have the right to provide the foregoing information to the Commission on a confidential basis if reasonably necessary to ensure compliance with applicable securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed), it being understood that certain information provided by the Large Participating Gas Utilities shall be disclosed pursuant to Ordering Paragraph C.9. It is further acknowledged that the Participating Gas Utilities may have further interests in providing any information it deems proprietary, trade secret or competitively sensitive pursuant to a reporting obligation contemplated in this Financing Order on a confidential basis.

16.4 The Commission finds that the foregoing information and agreements are necessary financial disclosure information as provided in Tex. Util. Code §§ 104.366(n) and 104.366(q) and Tex. Gov't Code §1232.1072(m).

17. Enforcement of Financing Order

17.1 The Commission guarantees, for the benefit of the Issuer Entity, the holders of the Customer Rate Relief Bonds, the Trustee and any other financing parties, that it will take all actions in its powers to enforce the provisions in this Financing Order to ensure that revenues collected from Customer Rate Relief Charges are sufficient to pay on a timely basis all scheduled principal and interest on the Customer Rate Relief Bonds and other components of the Periodic Payment Requirement and other Bond Administrative Expenses, as provided in Tex. Util. Code § 104.366(p).

E. Use of Proceeds

1. Upon the issuance of the Customer Rate Relief Bonds, the net proceeds of the Customer Rate Relief Bonds (after deduction of the Up-Front Financing Costs, including funding any reserves and funding of any capitalized interest, as applicable) will be held in trust by the Issuer Entity, in accordance with Tex. Util. Code §104.372(b), and the Issuer Entity will direct the Trustee to disburse such proceeds in an amount equal to the Aggregated Regulatory Asset Determination Amounts as set forth in Table 4 under Findings of Fact, Section IV.A.35 to Participating Gas Utilities in accordance with the terms of this Financing Order. Such net proceeds, will be disbursed to each Participating Gas Utility no later than the next business day following the date the Customer Rate Relief Bonds are issued (such date of issuance, the “Closing Date”), based on the amount of each Participating Gas Utility’s Aggregated Regulatory Asset Determination Amount as set forth in Table 4 under Findings of Fact, Section IV.A.35 and adjusted in accordance with this Financing Order; provided that a portion of the amount of the Regulatory Asset to be payable to CenterPoint shall be paid directly to Summit Utilities Inc. as a Successor Utility to CenterPoint as detailed in a written joint instruction letter to be provided to the Issuer Entity no later than fourteen (14) days prior to the anticipated Closing Date and signed by both CenterPoint and Summit Utilities Inc., specifying the amount to be paid to each such utility; the amount to be paid directly to Summit Utilities Inc. will not exceed \$7,489,359 (the “Summit Utilities Maximum”) and the amount to be paid directly to CenterPoint will not exceed \$1,093,173,515. The Issuer Entity and the Trustee shall be permitted to rely on such joint instruction letter. If, by the date that is anticipated to be fourteen (14) days before Closing Date, a written joint instruction letter has not been provided by Summit Utilities Inc. and CenterPoint to the Issuer Entity, then (i) the amount directly paid to Summit Utilities Inc. will be the Summit Utilities Maximum and (ii) the amount directly paid to CenterPoint will be the amount of the Regulatory Asset payable to CenterPoint less the Summit Utilities Maximum. On the date that occurs fifty (50) days after the date the Financing Order is issued, the Commission shall notify the Authority and Issuer Entity of any adjustments to the amount of Regulatory Assets discussed in the foregoing sentence in connection with the actual, documented, legal, consulting, and professional expenses of each Participating Gas Utility and each Intervenor. Such adjustments shall be factored into

the Issuer Entity's disbursement direction to the Trustee in respect of the Participating Gas Utilities. If the Closing Date occurs on or prior to the date that occurs fifty (50) days after the date this Financing Order is issued, the Designated Representative is authorized to provide for an alternate procedure for the disbursement of actual, documented, legal, consulting and professional expenses of each Participating Gas Utility and each Intervenor. For the avoidance of doubt, CenterPoint and Summit Utilities Inc. may agree and document in such joint instruction letter that CenterPoint will receive the amount equal to the actual, documented, consulting, and professional expenses of the applicable Intervenor as set forth in Table 3 in Findings of Fact, Section IV.A, titled "Procedural History: Phase 1, Regulatory Asset Determination Proceeding" and reimburse the applicable Intervenor pursuant to Finding of Fact No. 51.b in the Regulatory Asset Determination Order. Participating Gas Utilities and Successor Utilities, if applicable, will use the net proceeds to eliminate the regulatory assets approved in this proceeding. To the extent it is determined by the Authority and the Issuer Entity that capitalized interest is beneficial to effectuate the financing in accordance with the Authority Bond Standards, the period for any such capitalized interest shall not exceed six (6) months following the Closing Date. Subject to the foregoing limitation, any such period determined by the Authority and the Issuer Entity to be beneficial to effectuate the financing in accordance with the Authority Bond Standards is hereby permitted and determined to be necessary in accordance with Tex. Util. Code § 104.366(e)(4).

V. CONCLUSIONS OF LAW

1. Atmos Energy, Bluebonnet, CenterPoint, Corix, EPCOR, SiEnergy, TGS, and UniGas are gas utilities as that term is defined in Tex. Util. Code §§ 101.003(7) and 104.362(12).
2. The Commission issued a Regulatory Asset Determination Order in accordance with Tex. Util. Code § 104.365.
3. The Commission, after the final resolution of all applications filed under Tex. Util. Code § 104.365 and issuance of a financing order, may request that the Authority direct an issuing financing entity to issue Customer Rate Relief Bonds in accordance with Tex. Util. Code § 104.366(a).

4. In determining whether to issue a Financing Order, the Commission must find that the proposed structuring, expected pricing, and proposed financing costs of the Customer Rate Relief Bonds are reasonably expected to provide benefits to customers by (i) considering customer affordability; and (ii) comparing (A) the estimated monthly costs to customers resulting from the issuance of customer rate relief bonds, and (B) the estimated monthly costs to customers that would result from the application of conventional recovery methods. Tex. Util. Code § 104.366(a)-(b).
5. The proposed structuring, expected pricing, and proposed financing costs of the Customer Rate Relief Bonds are reasonably expected to provide benefits to customers when (i) considering customer affordability; and (ii) comparing the estimated monthly costs to customers resulting from the issuance of Customer Rate Relief Bonds and the estimated monthly costs to customers that would result from the application of conventional recovery methods. Tex. Util. Code § 104.366(b).
6. Customer Rate Relief Bond financing is the most cost-effective method of funding regulatory asset reimbursements to the Applicants. Tex. Util. Code § 104.366(a).
7. The issuance of Customer Rate Relief Bonds provides tangible and quantifiable benefits to customers, greater than would have been achieved absent the issuance of the Customer Rate Relief Bonds, as required under Tex. Util. Code § 104.361(b).
8. The use of the securitization financing mechanism is in the public interest and consistent with the purposes of Chapter 104 (Rates and Services), Subchapter I (Customer Rate Relief Bonds), Title 3 (Gas Regulation), Subtitle A (GURA) of the Utilities Code. Tex. Util. Code § 104.366(c)(1).
9. This Financing Order details the total maximum amount of the regulatory asset determinations to be included in the Customer Rate Relief Bond issuances in Finding of Facts, Section IV.A.35 in accordance with Tex. Util. Code § 104.366(c)(2).
10. This Financing Order authorizes the recovery of tax obligations of the gas utilities arising or resulting from (i) receipt of Customer Rate Relief Bond proceeds; or (ii) collection or remittance of Customer Rate Relief Charges. Tex. Util. Code § 104.366(c)(3).

11. This Financing Order authorizes the issuance of Customer Rate Relief Bonds through the issuing financing entity, Texas Natural Gas Securitization Finance Corporation, in accordance with Tex. Util. Code § 104.366(c)(4).
12. This Financing Order includes a statement of the maximum aggregated regulatory asset determination as stated in Findings of Fact, Section IV.A.35 to be included in the principal amount of the Customer Rate Relief Bonds in accordance with Tex. Util. Code § 104.366(c)(5)(A).
13. This Financing Order includes a statement of the maximum scheduled final maturity of the Customer Rate Relief Bonds, in Findings of Fact, Section IV.D.2.1 in accordance with Tex. Util. Code § 104.366(c)(5)(B).
14. This Financing Order includes a statement of the maximum interest rate that the Customer Rate Relief Bonds may bear, in Findings of Fact, Section IV.D.3 in accordance with Tex. Util. Code § 104.366(c)(5)(C).
15. This Financing Order provides for the imposition, collection, and mandatory periodic formulaic adjustment of Customer Rate Relief Charges by all Participating Gas Utilities and their Successor Utilities to ensure that the Customer Rate Relief Bonds and all related financing costs will be paid in full and on a timely basis by Customer Rate Relief Charges in accordance with Tex. Util. Code §§ 104.366(c)(6) and 104.370.
16. This Financing Order authorizes the creation of Customer Rate Relief Property in favor of the Issuer Entity and the pledge of Customer Rate Relief Property by the Issuer Entity to the payment of the Customer Rate Relief Bonds. Tex. Util. Code § 104.366(c)(7).
17. This Financing Order directs the Issuer Entity to disburse the proceeds of Customer Rate Relief Bonds, net of bond issuance costs, reserves, and any capitalized interest, to Participating Gas Utilities. Tex. Util. Code § 104.366(c)(8).
18. This Financing Order provides that Customer Rate Relief Charges be collected from and allocated among all customers of each Participating Gas Utility through uniform monthly

volumetric charges to be paid by customers as a component of gas cost, as stated in Ordering Paragraph Nos. B.1., B.2., and B.3 Tex. Util. Code § 104.366(c)(9).

19. This Financing Order reflects the commitment made by each Participating Gas Utility that the proceeds of the Customer Rate Relief Bonds received by such Participating Gas Utility are in lieu of recovery of costs reimbursed by such proceeds through the regular ratemaking process or other mechanism. Tex. Util. Code § 104.366(c)(10).
20. This Financing Order authorizes an increase to the principal amount determined by the Commission in the Regulatory Asset Determination Order sufficient to: (i) pay the financing costs associated with the issuance, including all Bond Administrative Expenses to be paid from the proceeds of the Customer Rate Relief Bonds; (ii) reimburse the Authority and the Commission for any costs incurred for the issuance of the Customer Rate Relief Bonds and related Bond Administrative Expenses; (iii) provide for any reserve fund or other fund established by Indenture; and (iv) capitalize interest for the period determined necessary by the Commission. Tex. Util. Code § 104.366(e).

VI. ORDERING PARAGRAPHS

Based upon the record, the findings of fact and conclusions of law set forth herein, and for the reasons stated above, this Commission orders:

A. Approval

1. **Authority to Securitize.** The Issuer Entity is authorized in accordance with this Financing Order and H.B. 1520 to securitize and to issue the Customer Rate Relief Bonds with a principal amount up to the sum of the Authorized Amount. The Authorized Amount shall be sufficient to fund the Total Aggregated Regulatory Asset Determination Amount as set forth in Table 4 under Findings of Fact, Section IV.A.35 plus the Up-Front Financing Costs, including without limitation, all Bond Administrative Expenses to be paid from the proceeds of the Customer Rate Relief Bonds, credit enhancements and other arrangements to enhance marketability of the Customer Rate Relief Bonds, as discussed in Ordering Paragraphs C.3, reimbursements to the Authority and the Commission for any financing costs incurred for the issuance of the Customer Rate Relief Bonds, including the cost of the Commission's, Authority's and the Issuer Entity's financial advisors and legal counsel

and other consultants. If the actual up-front financing costs are less than the Up-Front Financing Costs included in the principal amount securitized, the Periodic Billing Requirement for the first (1st) Scheduled True-Up Adjustment shall be reduced by the amount of such unused funds (together with interest, if any, earned from the investment of such funds) and such unused funds (together with such interest) shall be available for payment of debt service on the bond payment date next succeeding such True-Up Adjustment. Each of the Participating Gas Utilities and Intervenors shall file updated actual legal, consulting, and professional expenses with the Designated Representative within thirty-five (35) days of the issuance date of this Financing Order using reasonably detailed invoices. To the extent a Participating Gas Utility receives insurance proceeds, governmental grants and other sources of funding that compensate or otherwise reimburse or indemnify the Participating Gas Utility for extraordinary costs following the issuance of the Regulatory Asset Determination Order, such Participating Gas Utility shall record the amount in a regulatory liability account and that amount shall be reviewed in a future proceeding. If an audit conducted under a valid gas purchase agreement identifies a change of greater than five percent (5.0%) to the total amount of gas supply costs incurred during Winter Storm Uri, the gas utility may record the amount in a regulatory asset or regulatory liability account and that amount shall be reviewed for recovery in a future proceeding.

2. **Customer Rate Relief Property.** This Financing Order authorizes the creation of Customer Rate Relief Property and the pledge thereof as described in Findings of Fact, Sections IV.D.5, titled “Customer Rate Relief Property”.
3. **Provision of Information.** The Authority and Issuer Entity shall provide timely information as provided herein to the Designated Representative and Commission Staff, as applicable, in order to allow the Designated Representative to participate and perform its duties as described herein in a timely manner. The Designated Representative and Commission Staff, as applicable, shall provide the Authority and the Issuer Entity timely information, as described herein, in order to allow the Authority and the Issuer Entity to perform their duties with respect to the issuance of the Customer Rate Relief Bonds as required by H.B. 1520.

4. **Issuance Summary.** The Authority shall deliver to and file with the Commission an Issuance Summary no later than five (5) business days after the Closing Date. Such Issuance Summary shall set forth the final terms of the Customer Rate Relief Bonds in satisfaction of the Authority's initial statutory obligation and in order to assist the Commission in satisfying its statutory reporting obligations. The Issuance Summary shall include a description of each series of Customer Rate Relief Bonds, total principal amount, estimated amount of Up-Front Financing Costs, estimated amount of Ongoing Financing Costs through maturity, credit enhancements, weighted average life, call provisions and amortization schedules. The Authority shall also provide copies of all publicly available bond issuance documents, the Indenture and any related bond documents in connection with the Issuance Summary. The Designated Representative or a designee thereof is authorized to report the final amount of Up-Front Financing Costs attributable to the Commission's expenses in writing to the Authority within forty-five (45) days of the Closing Date. Within sixty (60) days of the Closing Date, the Authority shall submit to the Commission a final report of the total Up-Front Financing Costs.
5. **Approval of Customer Rate Relief Rate Schedule.** The Customer Rate Relief Rate Schedule, attached as Exhibit 1 to this Financing Order, is approved and will become effective on the date the Customer Rate Relief Bonds are issued.
6. **Approval of Description of Cash Flow Model.** The Description of Cash Flow Model, attached as Exhibit 2 to this Financing Order, is approved.
7. **Approval of Form of True-Up Adjustment Letter.** The Form of True-Up Adjustment Letter, attached as Exhibit 3 to this Financing Order, is approved.
8. **Approval of Collection and Reporting Principles.** The Collection and Reporting Principles, attached as Exhibit 4 to this Financing Order, are approved.
9. **Approval of Central Servicing Agreement Principles.** The Central Servicing Agreement Principles, attached as Exhibit 5 to this Financing Order, are approved.
10. **Collection and Reporting Arrangements.** The Participating Gas Utilities are hereby ordered to enter into Collection and Reporting Arrangements to carry out the requirements

of this Financing Order and facilitate the issuance of the Customer Rate Relief Bonds. Such Collection and Reporting Arrangements shall, without limitation, provide for procedures and other terms substantially consistent with the Collection and Reporting Principles established in Exhibit 4 hereto. The execution and delivery of such Collection and Reporting Arrangements by a Participating Gas Utility shall be a condition precedent to the receipt of proceeds of the Customer Rate Relief Bonds by it.

B. Customer Rate Relief Charges

1. **Imposition.** Each Participating Gas Utility and any Successor Utility, pursuant to Collection and Reporting Arrangements, shall bill all existing and future sales customers receiving service from such Participating Gas Utility or its Successor Utilities, for Customer Rate Relief Charges in an amount sufficient to recover the principal of, and interest on, the Customer Rate Relief Bonds plus Ongoing Financing Costs. For each period during which Customer Rate Relief Charges are in effect pursuant to this Financing Order and the Customer Rate Relief Schedule, Customer Rate Relief Charges shall be imposed in an amount sufficient to recover the aggregate Periodic Payment Requirement for such period.
2. **Collection.** Each Participating Gas Utility and its Successor Utilities shall collect from all existing and future customers receiving sales service from such Participating Gas Utility or its Successor Utilities, Customer Rate Relief Charges. Each Participating Gas Utility and its Successor Utilities shall continue to bill and collect the Customer Rate Relief Charges until all Customer Rate Relief Bonds and Ongoing Financing Costs are paid in full. Participating Gas Utilities and any Successor Utility shall collect the Customer Rate Relief Charge in accordance with Tex. Util. Code §104.362(7)(B).
3. **Nonbypassability.** The Customer Rate Relief Charges shall be nonbypassable charges. All existing and future customers receiving sales service from a Participating Gas Utility or its Successor Utilities shall be required to pay the Customer Rate Relief Charges. The obligations of Successor Utilities hereunder are binding by operation of law. Customer Rate Relief Charges shall not be subject to offset by any credit. Any collections from customers who make partial payments will be applied first to any outstanding Customer

Rate Relief Charges prior to the satisfaction of any other charges included on such customers' bills.

4. **True-Ups.** True-Up Adjustments of the Customer Rate Relief Charges shall be undertaken and conducted as described in Findings of Fact, Sections IV.D.9, titled "True-Up System" and IV.D.10, titled "Interim True-Up". Each Participating Gas Utility shall annually file with the Commission and the Central Servicer its Normalized Sales Volumes for the relevant twelve (12) month period no later than June 1 and more frequently to the extent required under the Servicing Agreement and applicable Collection and Reporting Arrangements. Each Large Participating Gas Utility shall, upon the request of the Central Servicer, provide the Commission and the Central Servicer updated Normalized Sales Volumes for the succeeding twelve (12) month period no later than the fifteenth (15th) day following such request to allow the Central Servicer to make Interim True-Up Adjustments. Each Large Participating Gas Utility shall have the right to provide the foregoing information to the Central Servicer on a confidential basis if reasonably necessary to ensure compliance with applicable securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed), it being understood that certain information provided by the Large Participating Gas Utilities shall be disclosed pursuant to Ordering Paragraph C.9. The bond issuance documents shall provide for True-Up Adjustments in a manner consistent with this paragraph.
5. **Rate Schedule Filings.** No later than forty-five (45) days following the issuance of the Financing Order, Participating Gas Utilities shall file with the Commission: (i) updated cost of gas rate schedules that include the Customer Rate Relief Charge as a component of the Participating Gas Utility's gas cost and (ii) the draft Customer Rate Relief Rate Schedule in substantially the same form as Exhibit 1 hereto.
6. **Tariff Filings.** Within thirty (30) days after the determination of the initial Customer Rate Relief Charge, each Participating Gas Utility shall electronically file an initial Customer Rate Relief Rate Schedule in accordance with 16 Tex. Admin. Code § 7.315. Within thirty

(30) days after the determination of any adjusted Customer Rate Relief Charge pursuant to the True-Up Adjustment mechanism, each Participating Gas Utility shall electronically file an updated Customer Rate Relief tariff that reflects the updated Customer Rate Relief Charge in Section E in accordance with 16 Tex. Admin. Code § 7.315.

7. **Collection and Reporting Costs.** Each Participating Gas Utility shall book and record Collection and Reporting Costs, as described in Findings of Fact, Section IV.C.1.6, titled “Collection and Reporting Costs”. Collection and Reporting Costs shall be reviewed in a subsequent rate proceeding.

C. **Customer Rate Relief Bonds**

1. **Ongoing Financing Costs.** Revenue from collections of Customer Rate Relief Charges shall be applied to pay Ongoing Financing Costs, which shall be subject to the Authority Bond Standards to the extent applicable.
2. **Collateral.** All Customer Rate Relief Property and other collateral shall be held and administered by the Trustee pursuant to the Indenture and related ancillary documentation. The Issuer Entity shall establish a collection account with the Trustee, with subaccounts to be established, in both cases, as described in Findings of Fact, Section IV.D.6, titled “Security for Bonds”.
3. **Original Issue Discount and Credit Enhancement.** Customer Rate Relief Bonds may provide original issue discount or provide for various forms of credit enhancement, including reserves, letters of credit, surety bonds, guarantees, hedging arrangements or liquidity support arrangements and other arrangements contemplated by Tex. Util. Code § 104.366(g). The Issuer Entity is statutorily permitted to establish various reserve funds, including a debt service reserve as an additional form of credit enhancement to promote the credit quality and marketability of the Customer Rate Relief Bonds, as described in Findings of Fact, Section IV.D.4.1 and in accordance with Ordering Paragraph No. C.2. The decision to use such additional arrangements, as described in Findings of Fact, Section IV.D.4.2, shall be permitted in order to receive the highest possible credit rating on the Customer Rate Relief Bonds or lowest all-in costs, if such arrangements would (i) be expected by the Issuer Entity to result in lower Customer Rate Relief Charges and (ii) not

expose the Customer Rate Relief Bond financing to higher risks and greater uncertainty about future costs. The Issuer Entity is authorized to enter into Credit Agreements or Ancillary Agreements in connection with this Financing Order.

4. **Maximum Interest Rate.** The weighted average interest rate for the Customer Rate Relief Bonds (based on scheduled maturities) shall not exceed five percent (5.0%); provided that the Designated Representative is authorized, on behalf of the Commission, to adjust such maximum interest rate subsequent to the date hereof, in consultation with the Issuer Entity pursuant to an ABS Delegation. In connection with the preceding sentence, the Designated Representative Authority is authorized to reasonably request all information in the Issuer Entity's, the Authority's, the lead underwriter's or structuring agent's possession that the Designated Representative deems reasonably necessary in order to adjust such maximum rate. Any such adjustment in maximum interest rate by the Designated Representative, on behalf of the Commission, shall be confirmed in writing to the Authority prior to pricing of the Customer Rate Relief Bonds. Subject to this Ordering Paragraph, the interest rate will be determined at the time of pricing of the Customer Rate Relief Bonds by the Issuer Entity within parameters established by the Authority in accordance with the Authority Bond Standards. In approving the interest rate, the Issuer Entity shall consider market conditions, any recommendations of the Designated Representative and information from advisors of the Issuer Entity and, if applicable, of the Designated Representative, and the structuring, marketing, and pricing process of the Customer Rate Relief Bonds in addition to other factors it deems relevant in its commercially reasonable discretion pursuant to an ABS Delegation, subject to ensuring compliance with the requirements set forth in Tex. Util. Code §104.366(c)(5)(C).
5. **Life of Bonds; Target Determination.** The scheduled final maturity date of the Customer Rate Relief Bonds shall not exceed thirty (30) years from the date of issuance of such bonds, except that the legal final maturity date for any tranche or class of bonds may be later, depending on rating agency and market considerations, as determined by the Issuer Entity consistent with the Financing Order and within parameters provided to the Issuer Entity by the Authority in accordance with the Authority Bond Standards. The Target Determination and determination of the scheduled final maturity date, as well as the other

final terms of the Customer Rate Relief Bonds shall be made in accordance with and consistent with the procedures and conditions described in Findings of Fact, Section IV.D.2.2.

6. **Capitalized Interest.** To the extent it is determined by the Authority and the Issuer Entity that capitalized interest is beneficial to effectuate the financing in accordance with the Authority Bond Standards, the period for any such capitalized interest shall not exceed six (6) months following the Closing Date. Subject to the foregoing limitation, any such period determined by the Authority and the Issuer Entity to be beneficial to effectuate the financing in accordance with the Authority Bond Standards is hereby permitted as provided in Tex. Util. Code § 104.366(e)(4).
7. **Designated Representative.** The Executive Director of the Commission, or such other officer or employee of the Commission as designated in writing to the Authority by the Executive Director, is hereby initially designated as the “Designated Representative” for purposes of this Financing Order. The Designated Representative shall work collaboratively with the Authority during the Issuance Process in a consultative role and provide input and advice to the Authority and/or the Issuer Entity, including providing the Target Determination described under Findings of Fact, Section IV.D.2.2, adjusting the authorized interest rate described under Findings of Fact, Section IV.D.3 and determining the bond payment periods described in Exhibit 2 hereto. The Designated Representative is authorized, empowered and directed from time to time and at any time to (i) execute, acknowledge and deliver in the name of the Commission and on behalf of the Commission all agreements, instruments, certificates or such other documents and (ii) take other actions on behalf of, and delegated to it by, the Commission, in either case, as may be necessary or desirable in order to effectuate the issuance or administration of the Customer Rate Relief Bonds on a basis consistent with this Financing Order. The Designated Representative may also specify any successor officer or employee of the Commission to serve in the role as Designated Representative as well as designate other staff, legal counsel, financial advisors and other consultants, to (i) assist the Commission in the Issuance Process for the Customer Rate Relief Bonds and (ii) act as its designee after the Closing Date. Any costs incurred by the Designated Representative in connection with the

Customer Rate Relief Bonds including those of its legal counsel, financial advisors and other consultants, shall be treated as Financing Costs. Each of the Designated Representative and the Commission Staff shall have the right to request all information from the Central Servicer, the Participating Gas Utilities and the Successor Utilities that the Designated Representative deems reasonably necessary to comply with the Financing Order or the Commission's statutory reporting obligations in relation to the Customer Rate Relief Bonds, including pursuant to Tex. Util. Code § 104.366(q). The Central Servicer, the Participating Gas Utilities and the Successor Utilities shall comply with such requests on a reasonably prompt basis and provide such information in the form requested by the Designated Representative or the Commission Staff. The Issuer Entity shall have the right to request that the Designated Representative review information prepared for the benefit of the rating agencies or for use in marketing the Customer Rate Relief Bonds and it is expected that the Designated Representative shall provide any feedback on a reasonable basis.

8. **Reporting Requirements for Authority.** The Authority shall make periodic reports to the public, and provide any other information or documentation requested by the Commission, regarding the Customer Rate Relief Bonds as required by Tex. Gov't Code § 1232.1072(m) if so requested by the Commission. Each of the Indenture, the Collection and Reporting Arrangements and any other relevant ancillary documentation shall provide that the Commission shall receive a copy of any notice of defaults or events of default under such document and any other material notices delivered under such document in order for the Commission to comply with its statutory obligations.
9. **Reporting Obligations of Participating Gas Utilities.** The Participating Gas Utilities shall promptly provide all requested information necessary to issue the Customer Rate Relief Bonds (including, but not limited to, information prepared for the benefit of rating agencies, information prepared for use in marketing the Customer Rate Relief Bonds to investors or information deemed necessary by the Authority and the Issuer Entity to satisfy state or federal securities laws) from and to the Authority and the Issuer Entity, through its counsel or designated representative, or the lead underwriter through its counsel, in a format reasonably satisfactory to the Issuer Entity. The Participating Gas Utilities shall

enter into agreements (binding against such Participating Gas Utility and any Successor Utility) that permit the underwriters to purchase the Customer Rate Relief Bonds pursuant to federal securities laws and regulations. The foregoing information and agreements are necessary financial disclosure information as provided in Tex. Util. Code § 104.366(n). It is acknowledged that any information so provided to the Issuer Entity for use in connection with the issuance of the Customer Rate Relief Bonds (i) must not contain any untrue statement of a material fact or (ii) omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading. The form of verifications to be made in connection with the foregoing sentence will be determined by the Participating Gas Utilities, the Issuer Entity, and the lead underwriter, through their respective representatives and/or counsel, and provided to the Issuer Entity, the lead underwriter and any other financing party as determined by such entities prior to the marketing of the Customer Rate Relief Bonds. Participating Gas Utilities shall promptly provide all information in the form requested by the Commission that the Commission deems reasonably necessary to comply with the Financing Order or the Commission's statutory reporting obligations in relation to the Customer Rate Relief Bonds, including pursuant to Tex. Util. Code § 104.366(q). It is further acknowledged that the Participating Gas Utilities may have further interests in providing any information it deems proprietary, trade secret or competitively sensitive pursuant to a reporting obligation contemplated in this Financing Order on a confidential basis. The foregoing information and agreements are necessary financial disclosure information as provided in Tex. Util. Code § 104.366(q).

10. **Remaining Balances Provisions.** The Indenture, the Servicing Agreement and any other relevant ancillary documentation shall provide for procedures and other terms substantially consistent with the Remaining Balances Provisions, as described in Findings of Fact, Section IV.D.6.4, and the Remaining Gas Utilities are directed to comply with the Remaining Balances Provisions in accordance with this Financing Order. Amounts received by a Participating Gas Utility pursuant to the Remaining Balances Provisions shall be recorded by such Participating Gas Utility in a regulatory liability account and that amount shall be reviewed in a future proceeding consistent with Tex. Util. Code § 104.372(c).

D. Servicing

1. **Servicing Agreement.** The Central Servicer will be an entity identified by the Commission hereinabove, which includes any of Bank of New York Mellon Corporation, U.S. Bank National Association and Alter Domus (US) or such other financial institution or professional services firm possessing the requisite experience and qualifications, consistent with achieving the highest possible ratings on the Customer Rate Relief Bonds, as identified by the Designated Representative on behalf of the Commission and will be a party to the Servicing Agreement, along with the other parties identified in Exhibit 5 hereto. Such Servicing Agreement shall be as described in Findings of Fact, Section IV.C, titled “Identification of Central Servicer; Collection and Reporting Arrangements” and, for the avoidance of doubt, shall, without limitation, provide for terms substantially consistent with the principles set forth in Exhibit 5 hereto.
2. **Collection and Reporting.** The Central Servicer shall have the authority to enter into and enforce the Collection and Reporting Arrangements and to enforce the terms thereof. Such Collection and Reporting Arrangements shall, without limitation, provide for procedures and other terms substantially consistent with the Collection and Reporting Principles, including but not limited to provisions under such Collection and Reporting Arrangements relating to the payment of certain costs and expenses as Ongoing Financing Costs. In the event of noncompliance by any Participating Gas Utility with its Collection and Reporting Arrangements and upon written request to the Commission by the Central Servicer, the Issuer Entity or the Trustee, the Commission will act promptly to enforce the obligations of the Participating Gas Utility (or Successor Utility) thereunder.

E. Use of Proceeds

1. **Use of Proceeds.** Upon the issuance of the Customer Rate Relief Bonds, the Issuer Entity shall disburse the net proceeds from the sale of the Customer Rate Relief Bonds (after payment of Up-Front Financing Costs) to Participating Gas Utilities. The net proceeds shall be disbursed to each Participating Gas Utility as described in Findings of Fact, Section IV.E, titled “Use of Proceeds”. Each Participating Gas Utility shall treat such net proceeds

as reimbursement for the extraordinary costs that they incurred to secure gas supply and provide service during Winter Storm Uri.

F. Miscellaneous Provisions

1. **Binding on Successors.** This Financing Order, together with the Customer Rate Relief Charges authorized in it, shall be binding on the Authority, the Issuer Entity, the Intervenor, the Participating Gas Utilities and any Successor Utility. In this paragraph, a “successor” means any entity that succeeds by any means whatsoever to any interest or obligation of its predecessor, including by way of bankruptcy, reorganization or other insolvency proceeding, merger, consolidation, conversion, assignment, pledge or other security, by operation of law or otherwise.
2. **Flexibility.** Subject to compliance with the requirements of this Financing Order, the Issuer Entity shall be afforded flexibility in establishing the terms and conditions of the Customer Rate Relief Bonds, including the final structure, repayment schedules, term, payment dates, collateral, credit enhancement, required debt service, reserves, use of original issue discount, and other financing costs.
3. **Effectiveness of Order.** This Financing Order is effective upon issuance and is not subject to rehearing by the Commission.
4. **Regulatory Approvals.** All regulatory approvals within the jurisdiction of the Commission that are necessary for the securitization of the Customer Rate Relief Charges and all related transactions contemplated in the application, are granted.
5. **Corrections and Cures.** Through the issuance of a supplement hereto or other means available to the Commission under law, the Commission may modify this Financing Order in order to correct, cure or resolve any ambiguity, defect or error, including typographical errors, manifest errors, calculation errors, cross-reference errors or inconsistencies in the Financing Order. For the avoidance of doubt, the foregoing shall not permit the reduction, impairment or adjustment of customer rate relief charges or be used in a manner contrary to Tex. Util. Code § 104.366(h).

6. **All Other Motions Denied.** All motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief not expressly granted herein, are denied for want of merit.

SIGNED on 2/8/2022.

RAILROAD COMMISSION OF TEXAS

DocuSigned by:

Wayne Christian

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CHAIRMAN WAYNE CHRISTIAN

DocuSigned by:

Christi Craddick

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COMMISSIONER CHRISTI CRADDICK

DocuSigned by:

Jim Wright

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COMMISSIONER JIM WRIGHT

DocuSigned by:

Callie Farrar

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COMMISSION SECRETARY



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Exhibit 1
Form of Rate Schedule
(Gas Utility Name)
Customer Rate Relief Rate Schedule

A. ABBREVIATIONS AND DEFINITIONS

- 1) Authority - The Texas Public Finance Authority, together with any successor to its duties and functions.
- 2) Bonds or Customer Rate Relief (“CRR”) Bonds - The “Texas Natural Gas Securitization Finance Corporation Customer Rate Relief Bonds, Series 2022” and any additional or different designation or title by which each series of Bonds shall be known as determined by the Issuer Entity.
- 3) Ccf and Mcf - For Ccf, one hundred (100) standard cubic feet of gas, where one (1) standard cubic foot of gas is the amount of gas contained in one (1) cubic foot of space at a standard pressure of fourteen point sixty-five (14.65) pounds per square inch, absolute and a standard temperature of sixty (60) degrees Fahrenheit; and, for Mcf, 1,000 standard cubic feet of gas.
- 4) Central Servicer - The entity engaged in accordance with the terms of the Financing Order to, amongst other things, engage the Participating Gas Utilities as collection agents for the purposes of facilitating collection and remittance of CRR Charges by Participating Gas Utilities, and perform the other services required of it under the Servicing Agreement (as defined in the Financing Order).
- 5) Commission - The Railroad Commission of Texas, including its staff or delegate.
- 6) CRR Charge True-Up Adjustment - A True-Up Adjustment (as defined in the Financing Order).
- 7) CRR Charge True-Up Charge Adjustment Letter - A true-up adjustment letter substantially in the form of Exhibit 3 to the Financing Order.
- 8) CRR Scheduled Adjustment Date – January 1 and July 1 of each applicable year, provided that the CRR Scheduled Adjustment Date and any other deadlines or target dates related thereto, shall be subject to modification prior to the date the Bonds so as to reflect the terms of the Servicing Agreement.
- 9) Customer Rate Relief (“CRR”) Charge - A nonbypassable charge as defined in Tex. Util. Code § 104.362(7).
- 10) Financing Order - The order adopted under Tex. Util. Code § 104.366 approving the issuance of CRR Bonds and the creation of Customer Rate Relief Property and associated

CRR Charges for the recovery of regulatory assets, including extraordinary costs, related financing costs, and other costs authorized by the Financing Order.

- 11) Gas Utility – [Name of Participating Gas Utility]⁷⁶ and its successors and assignees, an operator of natural gas distribution pipelines that delivers and sells natural gas to the public and that is subject to the Commission’s jurisdiction under Tex. Util. Code § 102.001, or an operator that transmits, transports, delivers, or sells natural gas or synthetic natural gas to operators of natural gas distribution pipelines and whose rates for those services are established by the Commission in a rate proceeding filed under Chapter 104 of the Utilities Code, within the service area.
- 12) Irrevocable - The Financing Order, together with the Customer Rate Relief Property as defined by Tex. Util. Code § 104.362(8) and the CRR Charges authorized by the Financing Order, are irrevocable and not subject to reduction, impairment, or adjustment by further action of the Commission, except in connection with true-ups authorized by the Financing Order.
- 13) Issuer Entity - Texas Natural Gas Securitization Finance Corporation, a Texas nonprofit public corporation established by the Authority, or any successor created pursuant to Tex. Gov’t Code § 1232.1072.
- 14) Large Participating Gas Utility - Atmos Energy Corporation on behalf of its Mid-Tex Division and West Texas Division; CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex, CenterPoint Energy Arkla, and CenterPoint Energy Texas Gas; Texas Gas Service Company, a Division of ONE Gas, Inc., excluding the West Texas Service Area; and any Participating Gas Utility or Successor Utility (as defined in the Financing Order) each of whose Normalized Sales Volumes exceed 2.0% of the total aggregate Normalized Sales Volumes among all Participating Gas Utilities. Any calculation performed in connection with the preceding sentence shall be made on the basis of the most recently reported Normalized Sales Volumes and such calculation shall be performed by the Central Servicer annually no later than one (1) month after Normalized Sales Volumes are reported as regularly scheduled under Paragraph H hereof; provided that the Commission and/or Central Servicer may perform such calculation without any limitation in order to give effect to any merger, acquisition, disposition, divestiture, spin-off or other transaction that would impact a Participating Gas Utility’s share of the total aggregate Normalized Sales Volumes. The Commission or the Central Servicer shall promptly thereafter provide written notice to a Participating Gas Utility that subsequently becomes a Large Participating Gas Utility, which change shall take effective beginning on January 1 of the following calendar year.
- 15) Nonbypassable - CRR Charges must be paid by all existing or future customers receiving service from a Participating Gas Utility or such gas utility’s successors or assigns.
- 16) Normalized Sales Volumes –

⁷⁶ To reflect Participating Gas Utility filing Rate Schedule.

- a) For Large Participating Gas Utilities: All natural gas volumes projected to be billed for the upcoming twelve (12) month period in conjunction with the operation of a Participating Gas Utility's Purchase Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs. For the avoidance of doubt, only the Normalized Sales Volumes of Large Participating Gas Utilities shall be aggregated to calculate the CRR Charges.
- b) For other Participating Gas Utilities: All natural gas volumes billed in the preceding calendar year in conjunction with the operation of a Participating Gas Utility's Purchase Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs and normalized according to the methodology utilized in each Participating Gas Utility's application filed in Docket No. OS-21-00007061, *Consolidated Applications For Customer Rate Relief and Related Regulatory Asset Determinations In Connection With The February 2021 Winter Storm*. For the avoidance of doubt, only the Normalized Sales Volumes of Large Participating Gas Utilities shall be aggregated in order to calculate the CRR Charges.
- 17) Participating Gas Utilities - AgriTexGas, L.P.; Atmos Energy Corporation on behalf of its Mid-Tex Division and West Texas Division; Rockin' M Gas LLC d/b/a Bluebonnet Natural Gas LLC; CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex, CenterPoint Energy Arkla, and CenterPoint Energy Texas Gas; Corix Utilities (Texas) Inc.; EPCOR Gas Texas Inc.; NatGas, Inc.; SiEnergy, LP; Texas Gas Service Company, a Division of ONE Gas, Inc., excluding the West Texas Service Area; and Universal Natural Gas, LLC d/b/a Universal Natural Gas, Inc. or any Successor Utility (as defined in the Financing Order).
- 18) Sales Customer(s) - All active customers taking service under a Participating Gas Utility's Purchase Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs.

B. APPLICABILITY

This rate schedule sets out the rate, terms and conditions under which the CRR Charge shall be billed and collected by [Name of Participating Gas Utility]⁷⁷ as a Participating Gas Utility for the [Unincorporated/Incorporated]⁷⁸ area of the [Name of Division/Service Area]⁷⁹ under the terms of the Financing Order. Each individual Sales Customer is responsible for paying the CRR Charge billed to it in accordance with the terms of this rate schedule. Payment is to be made by an individual Sales Customer to the Participating Gas Utility of which it is a customer. The Participating Gas Utility is obligated to apply amounts collected from customers to pay any outstanding CRR Charges prior to applying such amounts for any other purpose. The Participating Gas Utility, as collection agent,

⁷⁷ To reflect Participating Gas Utility filing Rate Schedule.

⁷⁸ To reflect status of applicable Division/Service Area.

⁷⁹ To reflect applicable Division/Service Area.

shall remit collections of the CRR Charges to the [Trustee]⁸⁰ in accordance with the terms of the Financing Order and any servicing or other similar agreement that is contemplated by the Financing Order.

C. TERM

This rate schedule shall remain in effect until the CRR Charges have been collected and remitted to the [Trustee]⁸¹ in an amount sufficient to satisfy all obligations in regard to paying principal and interest on the CRR Bonds together with all other financing costs, bond administrative expenses and other costs as provided in the Financing Order. This rate schedule and the CRR Charge are irrevocable and Nonbypassable.

D. SALES CUSTOMERS

For the purposes of billing the CRR Charges, all Sales Customers of the Participating Gas Utility's [Name of Division/Service Area]⁸² shall be assessed the uniform volumetric charge identified below.

E. CRR CHARGE

The CRR Charge will be a monthly volumetric rate of [\$____/Mcf] [\$____/Ccf]. The CRR Charge is calculated in accordance with and subject to the provisions set forth in the Financing Order and will be adjusted at least annually based upon the CRR Charge true-up adjustment procedure. The CRR Charge shall be included in the Participating Gas Utility's Purchase Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs. Participating Gas Utilities may reflect the CRR Charge according to the delivery pressures defined in Participating Gas Utilities' applicable tariffs. Such delivery pressure specific charges shall be equivalent to the CRR Charge as determined below at 14.65 per square inch, as defined above.

F. DETERMINATION OF CUSTOMER RATE RELIEF CHARGE

The CRR Charge will be adjusted no less frequently than annually, in accordance with the terms of the Servicing Agreement (as defined in the Financing Order), to ensure that the expected collection of CRR Charges is adequate to pay when due, pursuant to the expected amortization schedule, principal and interest on the CRR Bonds and together with all other financing costs, bond administrative expenses and other costs, as provided in the Financing Order, on a timely basis. The CRR Charge shall be computed according to the formula described below.

Step 1: Determination of Normalized Sales Volumes
(A) Total Large Participating Gas Utility Normalized Sales Volumes (Mcf)
(B) Assumed % of uncollectible sales

⁸⁰ To reflect entity acting as indenture trustee in connection with the CRR Bonds.

⁸¹ To reflect entity acting as indenture trustee in connection with the CRR Bonds.

⁸² To reflect applicable Division/Service Area.

(C) Total Normalized Sales Volumes Billed and Collected: $(A * (1 - B))$

For the avoidance of doubt, Normalized Sales Volumes are assumed to be calculated without giving effect to volumes anticipated from Participating Gas Utilities making up less than two percent (2.0%) of the total Normalized Sales Volumes of all Participating Gas Utilities.

Step 2: Determination of CRR Charge
(D) Total CRR Charge Rate Revenue Requirement for Applicable Period
(E) CRR Charge per Normalized Sales Volumes (Mcf): (D / C)
<i>Thereof: CRR Charge for Sales Customers</i>

G. CRR CHARGE TRUE-UP

Changes to the CRR Charge will be effected through the filing of CRR Charge True-Up Adjustment Letters by the Central Servicer to the Commission as authorized by the Financing Order and in accordance with the Servicing Agreement. Not less than fifteen (15) days prior to each CRR Scheduled Adjustment Date and more frequently as required by the Central Servicer, the Central Servicer will submit the CRR Charge True-Up Adjustment Letter in the form of Exhibit 3 to the Financing Order to ensure that CRR Charge collections are sufficient to make all scheduled payments of CRR Bond principal and interest and meet other Ongoing Financing Costs (as defined in the Financing Order) on a timely basis during the payment period.

In addition to the foregoing, the Central Servicer shall be authorized to file CRR Charge True-Up Adjustment Letters with the Commission that adjust the CRR Charge more frequently (but not more often than quarterly) as required under the provisions of the Servicing Agreement (as defined in the Financing Order).

H. CRR CHARGE TRUE-UP PROCEDURE

[Name of Participating Gas Utility]⁸³ shall annually file with the Commission and the Central Servicer by June 1 of each year its Normalized Sales Volumes; each Large Participating Gas Utility shall include projected volumes for each of the future twelve (12) months beginning July 1, and each other Participating Gas Utility shall include its Normalized Sales Volumes for the prior calendar year. Such filing and/or reporting may be more frequent to the extent required under the Servicing Agreement and applicable Collection and Reporting Arrangements. If [Name of Participating Gas Utility]⁸⁴ is a Large Participating Gas Utility, the Participating Gas Utility shall, upon the request of the Central Servicer, provide the Commission and the Central Servicer updated Normalized Sales Volumes for the succeeding twelve (12) month period no later than the fifteenth (15th) day following such request to allow the Central Servicer to make Interim True-Up Adjustments. Each Participating Gas Utility shall have the right to provide the foregoing information to the Central Servicer on a confidential basis if reasonably necessary to ensure compliance

⁸³ To reflect Participating Gas Utility filing Rate Schedule.

⁸⁴ To reflect Participating Gas Utility filing Rate Schedule.

with applicable securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed). The Central Servicer shall submit to the Commission and the Participating Gas Utilities, not less than fifteen (15) days prior to the CRR Scheduled Adjustment Date, a CRR Charge True-Up Adjustment Letter applying the CRR Charge True-Up Adjustment based on Normalized Sales Volumes and other mathematical factors and requesting administrative approval from the Commission as provided for in the Servicing Agreement. The Commission's review and approval of the True-Up Adjustment Letter shall be as set forth in the Servicing Agreement (it being understood such review is limited to determining if any mathematical or clerical errors are present in the application of the CRR Charge True-Up Adjustment relating to the appropriate amount of any over-collection or under-collection of CRR Charges and the amount of an adjustment).

If any CRR Charge True-Up Adjustment that is an Interim True-Up Adjustment is necessary, (i) the Central Servicer may request and the Large Participating Gas Utilities shall provide revised Normalized Sales Volumes for each of the immediately succeeding twelve (12) months and related data and (ii) within fifteen (15) days of receipt of such data, the Central Servicer shall file a revision to the CRR Rate Schedule in a True-Up Charge Adjustment Letter setting forth the adjusted CRR Charge to be effective for the upcoming period, in accordance with the Servicing Agreement. The [Name of Participating Gas Utility]⁸⁵ shall have the right to provide such information on a confidential basis if reasonably necessary to ensure compliance with applicable securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed). A CRR Charge resulting from a true-up adjustment will become effective on the first (1st) billing cycle that is not less than fifteen (15) days following the making of the CRR Charge True-Up Adjustment filing.

I. TAXABILITY

The receipt of CRR Charges by a Participating Gas Utility is exempt from state and local sales and use taxes and utility gross receipts taxes and assessments and is excluded from revenue for purposes of franchise tax under Tex. Tax Code § 171.1011.

⁸⁵ To reflect Participating Gas Utility filing Rate Schedule.

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Exhibit 2: Description of Cash Flow Model

Introduction

The purpose of this exhibit is to describe the cash flow model used to calculate the Customer Rate Relief Charge (“CRRC”) for Sales Customers.

The remainder of this exhibit is organized as follows:

- Overview of the Bond Cash Flow Model; and
- CRR Charge calculation

Overview of the Bond Cash Flow Model

The cash flow model for the Customer Rate Relief Bonds (“CRR Bonds”) models (i) the expected revenue requirement necessary to pay debt service on the CRR Bonds and all other Ongoing Financing Costs and (ii) the CRRC based upon (A) the projected Normalized Sales Volumes of gas sales in aggregate for the Large Participating Gas Utilities and the projected losses (uncollectible amounts) associated with collections by the Large Participating Gas Utilities for the applicable period during which such charges will be in effect, as required under the terms of the Collection and Reporting Arrangements, all as calculated and periodically provided to the Central Servicer and the Commission by the Large Participating Gas Utilities, and (B) all scheduled payments of principal and interest and other Ongoing Financing Costs during the period for which such adjusted Customer Rate Relief Charges are to be in effect (such amounts are defined in the Financing Order as the Periodic Payment Requirement). The model determines the annual CRRC revenue requirement and CRRC necessary to collect sufficient funds to pay the interest and principal on the CRR Bonds, as well as the servicing fees, trustee fees, credit rating agency fees, and Ongoing Financing Costs (as defined in the Financing Order), (including for the avoidance of doubt the amounts necessary to replenish any reserve fund established by indenture for the CRR Bonds).

CRRC Calculation

The Bonds cash flow model will calculate the CRRC for any annual or other period that will apply to Customers for each Participating Gas Utility. The CRRC for any annual or other period will be determined as described below:

Step 1: The Central Servicer shall determine, through consultations with the Trustee and the Issuer Entity, the Periodic Payment Requirement required to be paid or provided for during the applicable period.

Step 2: The Large Participating Gas Utilities shall provide to the Central Servicer and the Commission the Normalized Sales Volumes for such 12-month or shorter period based on projections, as adjusted for uncollectible amounts, as set forth in the Financing Order.

Step 3: The Central Servicer shall determine the CRRC (i.e., rate per Mcf) for such applicable period by dividing the Adjusted Aggregate Projected Normalized Sales Volume for such period. The CRRC to be imposed will be calculated by the Central Servicer. The determination of the dates of the bond payment periods shall be subject to review by and consultation with the Designated Representative.

For any applicable period, $CRRC = (PPR - EFAB) / AANSV$

$AANSV = \text{Adjusted Aggregate Normalized Sales Volume} = (ANSV * (1 - UF))$

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PPR = Sum of the Periodic Payment Requirement for both semi-annual bond payment periods

EFAB = Excess Funds Account Balance

ANSV = Aggregate Normalized Sales Volume (aggregate of Normalized Sales Volume for Large Participating Utilities) for the applicable period

UF = Uncollectible Factor of one percent (1.0%) of ANSV (subject to adjustment from time to time by the Commission based upon actual delinquencies)

The cash flow requirements for each applicable period will further reflect that (i) CRRC collections will be remitted no less frequently than once every two (2) business days for the Large Participating Gas Utilities and held by the Trustee in a general collection account for distribution to Bondholders in accordance with the indenture for the CRR Bonds; and (ii) that the CRRC will be assumed to be collected by the Large Participating Utilities thirty (30) days after billing the CRRC, or such longer or shorter period determined by the Commission.

**Exhibit 3:
Form of True-Up Adjustment Letter**

[DATE]

VIA ELECTRONIC FILING

Railroad Commission of Texas
[P.O. Box 12967
Austin, Texas 78711-2967]

**RE: [SERVICER] True-Up Adjustment Letter
Financing Order, Docket OS-21-00007061**

Dear []:

As authorized by the financing order of the Railroad Commission of Texas (the “Commission”) adopted on February 8, 2022, in the above-referenced matter (the “Financing Order”), and pursuant to a servicing agreement dated [], 2022, amongst [], [] and [SERVICER], as servicer, and on behalf of the Texas Natural Gas Securitization Finance Corporation, submits this filing for [a scheduled true-up adjustment][an interim true-up adjustment] to the Customer Rate Relief Charges for Series __, Tranche(s) __ of the Customer Rate Relief Bonds (“CRR Bonds”). Capitalized terms used but not defined herein shall have the meanings ascribed to them in the Financing Order.

[SERVICER] has calculated the true-up adjustment in accordance with the Servicing Agreement. This calculation is based upon information provided to [SERVICER] pursuant to the Servicing Agreement, as shown in Attachment 1. These submissions are intended to ensure that the actual revenues collected under the Customer Rate Relief Charges will be sufficient to make all scheduled payments of CRR Bond principal, interest, and other Ongoing Financing Costs (as defined in the Financing Order) on a timely basis.

Upon the filing of a True-Up Adjustment Letter made pursuant to the Financing Order, the Commission shall either administratively approve the requested true-up calculation in writing or inform the [SERVICER], the Issuer Entity and the Authority of any mathematical or clerical errors in its calculation as expeditiously as possible but no later than fifteen (15) days following the servicer’s true-up filing; and that notification and correction of any mathematical or clerical errors shall be made so that the true-up is implemented within fifteen (15) days of the servicer’s filing of a True-Up Adjustment Letter. No potential modification to correct an error in a True-Up Adjustment Letter shall delay its effective date and any correction or modification, which could not be made prior to the effective date, shall be made in a subsequent True-up Adjustment Letter. Upon administrative approval or the passage of fifteen (15) days without notification of a mathematical or clerical error, no further action of this Commission will be required prior to implementation of the true-up.

Attachment 1 hereto is the Customer Rate Relief Charge True-Up Mechanism Form, reflecting the revised Customer Rate Relief Charge calculations and supporting work papers.

Pursuant to the Financing Order, the proposed adjustments to the Customer Rate Relief Charge will become effective on [DATE].

Respectfully submitted,

Exhibit 3-1

[SERVICER]

By: _____
Name:
Title:

[Cc to the Authority, the Issuer Entity the Participating Gas Utilities and, as applicable, their Successor Utilities and the Trustee]

A. Attachment 1: Customer Rate Relief Charge True-Up Mechanism Form⁸⁶

⁸⁶ Attachment to be included in Servicing Agreement.

Exhibit 4:
Collection and Reporting Principles

Any capitalized terms not defined in this Exhibit 4 shall have the meanings ascribed to them in the Financing Order.

1. **Billing and Collection.** The Participating Gas Utility shall, as collection agent, bill all its sales customers for and collect the Customer Rate Relief Charges, as calculated and adjusted from time to time, as contemplated by the Financing Order: (i) with reasonable care and in material compliance with applicable requirements of law (including the Financing Order), using the same degree of care and diligence that the Participating Gas Utility exercises with respect to similar assets for its own account; (ii) use all reasonable efforts, consistent with its customary collection procedures, to bill and collect the Customer Rate Relief Charges; and (iii) comply with all requirements of law, applicable to and binding on it relating to the Customer Rate Relief Property. The Participating Gas Utility shall follow such customary and usual practices and procedures that comply with the requirements of the Financing Order and Indenture as it shall deem necessary or advisable in discharging its obligations in respect of the Customer Rate Relief Property. The Participating Gas Utility shall begin charging the Customer Rate Relief Charge in the first billing cycle that is not less than fifteen (15) days following the issuance of notice from the Central Servicer that the Customer Rate Relief Charge is effective and continue until the Participating Gas Utility receives notice from the Central Servicer, copying the Commission, that the Customer Rate Relief Bonds (the “Bonds”) are no longer outstanding and all other amounts required to be paid by the Customer Rate Relief Charges under the Financing Order have been paid (the “Pay-Off Notice”).
2. **Remittance of Charges.** If the Participating Gas Utility is a Large Participating Gas Utility, it shall remit Customer Rate Relief Charges to the appropriate account specified by the Issuer Entity and held by the Trustee as soon as reasonably practicable but in no event later than the second (2nd) business day after such charges are received by such Participating Gas Utility and otherwise, the Participating Gas Utility shall remit Customer Rate Relief Charges to the appropriate account specified by the Issuer Entity and held by the Trustee within a time period to be determined by such Participating Gas Utility and the Central Servicer, at the direction of the Issuer Entity or Authority, in order to ensure the Customer Rate Relief Bond financing is the most cost-effective method of funding gas utility reimbursements (but in no case less frequently than monthly). Each Participating Gas Utility shall report on such remittances as described below in paragraph 4. Collection and Reporting Arrangements may permit a Participating Gas Utility to remit Customer Rate Relief Charges on an estimated basis, but in such case, the Participating Gas Utility shall reconcile such remittances not less often than annually. The Participating Gas Utility may provide for credit enhancement arrangements to support its collection and remittance obligations if the Authority and Issuer Entity jointly determine such credit enhancement arrangements would result in a more cost-effective method of funding gas utility reimbursements. For the avoidance of doubt, (i) any such credit enhancement arrangement shall be subordinate to such Participating Gas Utility’s obligations in respect of Customer Rate Relief Property and (ii) governed by terms reasonably satisfactory to the parties to the applicable Collection and Reporting Arrangement, including the Participating Gas Utility.

3. **Information Reporting.** The Participating Gas Utility shall provide Normalized Sales Volumes for the relevant twelve (12) month period in a manner consistent with the form of Rate Schedule attached to the Financing Order and provide other information as determined by the Central Servicer to be necessary to allow the Central Servicer to calculate and adjust the Customer Rate Relief Charge and comply with the Financing Order. If the Participating Gas Utility is a Large Participating Gas Utility, it shall issue a notice of “Material Change in Projections” to the Central Servicer to the extent such projected sales in any month (or longer period to be agreed) will be reduced by a percentage to be agreed and based on a standard to be agreed compared to the most recent Normalized Sales Volumes reported to the Central Servicer. If the Participating Gas Utility is a Large Participating Gas Utility, it shall notify the Commission and Central Servicer in writing to the extent actual collections vary materially from the uncollectible factor then in effect for a number of billing cycles to be determined and such written notice shall describe such variance and include any relevant information in connection therewith. Following the receipt of any notice contemplated in the preceding two sentences, the Commission and/or Central Servicer will take further action as described in in Findings of Fact, Sections IV.D.9.3 of the Financing Order. Upon request by the Issuer Entity or Central Servicer for information that is reasonably required to comply with any reporting requirements to which the Issuer Entity has reasonably agreed in order to facilitate the issuance of the Bonds, the Participating Gas Utility shall promptly provide such information to the Issuer Entity or Central Servicer in the form requested. Any projections provided by the Participating Gas Utility to the Central Servicer in accordance with this paragraph shall be certified by a responsible officer of such Participating Gas Utility in a manner that is customary for transactions of this type.
4. **Other Information.** Upon the Participating Gas Utility’s receipt of the reasonable written request of the Central Servicer, the Commission or the Issuer Entity, the Participating Gas Utility shall provide to the Central Servicer, the Commission, and the Issuer Entity, any financial information in respect of the Participating Gas Utility, or any information regarding the Customer Rate Relief Property, in each case to the extent it is reasonably necessary and permitted by law to allow the Central Servicer and the Commission to monitor the performance by the Participating Gas Utility hereunder, including as may be required by rating agencies. The Participating Gas Utility shall have the right to provide the foregoing information discussed in Paragraphs 3 and 4 to the Central Servicer, the Commission and Issuer Entity on a confidential basis if reasonably necessary to ensure compliance with applicable securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed). In addition, so long as any of the Bonds are outstanding, the Participating Gas Utility shall provide the Central Servicer and the Commission any information available to the Participating Gas Utility or reasonably obtainable by it that is necessary to calculate the Customer Rate Relief Charge. For the avoidance of doubt, this paragraph 4 shall, under no circumstances, prejudice or otherwise limit any disclosure obligations of the Participating Gas Utility contemplated by or provided in the Financing Order.
5. **Annual Reports on Compliance.** On or before March 31 of each year, beginning March 31, 2023, or on a later date to be agreed in accordance with customary reporting covenants, and until the Participating Gas Utility receives the Pay-Off Notice, the Participating Gas Utility

shall deliver to the Central Servicer and the Commission an annual report, in a form to be agreed by the Central Servicer, on behalf of the Issuer Entity, and each Large Participating Gas Utility or, if required by the Issuer Entity and the Commission, each other Participating Gas Utility, setting forth the Customer Rate Relief Charge revenues received by such Participating Gas Utility during the prior calendar year and remitted to the Trustee reconciling actual and estimated remittances during such period (if applicable), and stating that the Participating Gas Utility has complied with the terms and procedures of the Collection and Reporting Arrangements contemplated by this Exhibit 4, or if it has failed to so comply, identifying such non-compliance.

6. **Costs and Expenses.** Costs of the Participating Gas Utility (including, but not limited to legal and consulting costs) associated with complying with the relevant Collection and Reporting Arrangements shall be recovered through a subsequent rate proceeding as described in Findings of Fact, Section IV.C.1.6, titled “Collection and Reporting Costs” of the Financing Order.
7. **Successors; Amendments etc.** A Successor Utility shall be required to assume all obligations under the relevant Collection and Reporting Arrangements in accordance with the terms thereof, provided that either amendments or substitute Collection and Reporting Arrangements may be entered into if such amendments or replacement Collection and Reporting Arrangements are substantially similar to the Collection and Reporting Arrangements being replaced and substantially consistent with the Collection and Reporting Principles.
8. **Third-Party Beneficiaries; Enforcement.** In the event of noncompliance by any Participating Gas Utility with its Collection and Reporting Arrangements and upon written request to the Commission by the Central Servicer, the Issuer Entity or the Trustee, the Commission will act promptly to enforce the obligations of the Participating Gas Utility (or Successor Utility) thereunder. Each of the Trustee, the Commission and the Issuer Entity shall be a third-party beneficiary to any rights and interests of the Central Servicer in the Collection and Reporting Arrangements. The Issuer Entity, acting on behalf of the Trustee, is also authorized to enforce the Collection and Reporting Arrangements.

Exhibit 5:**Central Servicing Agreement Principles**

To the extent permitted by applicable law, the definitive Servicing Agreement will reflect the following terms and such other relevant terms as are set forth in the Financing Order; provided that this exhibit to the Financing Order is intended as an outline only and does not purport to summarize or contain all the conditions, covenants, representations, warranties and other provisions with respect to the Servicing Agreement, all of which shall be contained in the definitive legal documentation.

Any capitalized terms not defined in this Exhibit 5 shall have the meanings ascribed to them in the Financing Order to which this is attached. Any capitalized terms not defined in this Exhibit 5, or the Financing Order shall have the meanings to be ascribed to them in the definitive Indenture or Servicing Agreement.

Business Term	Summary
Proposed Parties:	• Central Servicer; • Issuer Entity; • Commission;
Choice of Law:	Texas
Term	The term of the Servicing Agreement will not terminate until all the principal of and interest on the Customer Rate Relief Bonds, and all other obligations that may be paid by use of Customer Rate Relief Charges have been paid or defeased and discharged.
General Duties of Central Servicer:	• Calculation of the Periodic Payment Requirement using information provided to it, including by the Trustee, the Issuer Entity and third-party sources (e.g., rating agencies) as necessary. • Calculation of True-Up Adjustments, including related inputs based on information provided by (i) Trustee, (ii) Issuer Entity, (iii) the Commission and (iv) Large Participating Gas Utilities. • Confirming that annual compliance reports have been filed by the Participating Gas Utilities and True-Up Adjustments approved or deemed approved by the Commission have been implemented, in each case, as contemplated by the Financing Order. • Monitoring compliance with the Collection and Reporting Arrangements by the Participating Gas Utilities. • Entering into the Collection and Reporting Arrangements and providing notice to Trustee, Commission, and Issuer Entity of any failures/defaults by a Participating Gas Utility (including any Successor Utility), as collection agent, under the Collection and Reporting Arrangements (each, a “<u>Collection Agent</u>” and collectively, the “<u>Collection Agents</u>”). • Tracking collections of Customer Rate Relief Charges remitted by the Participating Gas Utilities to the Trustee and comparing such collections with projected collections as reported by Large Participating Gas Utilities. • Compiling and organizing for dissemination purposes information in connection with agreements binding against Continuing Disclosure Participants entered into in accordance with the Financing Order (the “<u>Continuing Disclosure Agreements</u>”). • Maintaining records related to above referenced services for benefit of Issuer Entity, the Commission, the Trustee, and holders of the Customer Rate Relief Bonds (“<u>Holders</u>”).
Initial Charge:	• The Central Servicer shall provide the Collection Agents notice of the initial Customer Rate Relief Charge calculated by the Central Servicer prior to the date of the Customer Rate Relief Bonds are issued by delivery of the notice of initial charge letter, signed by the Central Servicer.

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Business Term	Summary
True-Up Adjustments:	• The Customer Rate Relief Charge and any True-Up Adjustment shall be calculated by the Central Servicer, in accordance with the Financing Order. • Notice of all True-Up Adjustments shall be delivered by the Central Servicer to the Commission, the Issuer Entity, the Participating Gas Utilities and, as applicable, their Successor Utilities and the Trustee by delivery of a letter, in the form attached to the Servicing Agreement (each a “<u>True-Up Letter</u>”) in accordance with the Financing Order. Each True-Up Letter shall include calculation by the Central Servicer of the Customer Rate Relief Charge as set forth in the schedule to the form of True-Up Letter (the “<u>Calculation Schedule</u>”) included in the Servicing Agreement.
Interim True-Up Adjustments:	If (i) notice of a Material Change (to be defined in the Servicing Agreement) in Projections (to be defined in the Servicing Agreement) shall have been received by the Central Servicer from any of the Large Participating Gas Utilities or (ii) a Potential Deficiency Event (to be defined in the Servicing Agreement) has occurred, and a scheduled true-up calculation date is not scheduled to occur for a duration to be agreed, the Central Servicer shall declare the need to implement an Interim True-Up Adjustment and shall provide notice, in the form attached to the Servicing Agreement (an “ <u>Interim Adjustment Notice</u> ”), to the Trustee, the Issuer Entity, the Commission and the Participating Gas Utilities that an Interim True-Up Adjustment to the Customer Rate Relief Charge will take place subject to any applicable limitations on True-Up Adjustments as set forth in the Financing Order.
Collections Tracking:	The Central Servicer will review each month (i) the Trustee’s report of monthly deposits made to the collections account held by the Trustee and delivered to the Central Servicer under the terms of the Indenture ⁸⁷ , and (ii) the certificates of projections ⁸⁸ delivered to the Central Servicer by the Large Participating Gas Utilities under the terms of the applicable Collection and Reporting Arrangements. On the date of such review, using the “Deficiency Calculation Worksheet” attached to the Servicing Agreement, the Central Servicer shall calculate the amount by which, if any, Projected Aggregate Collections (to be defined in the Servicing Agreement) during the applicable Deficiency Calculation Period (to be defined in the Servicing Agreement) exceeded Actual Aggregate Collections (to be defined in the Servicing Agreement). If Projected Aggregate Collections during such Deficiency Calculation Period exceeded Actual Aggregate Collections by more than a percentage to be agreed, the Central Servicer will (x) declare a Potential Deficiency Event, (y) notify the Issuer Entity, the Trustee, the Commission and the Participating Gas Utilities and (z) implement an Interim True-Up Adjustment subject to the criteria and conditions set forth in the Servicing Agreement.
Central Servicer Certificate:	Not later than a number of days to be agreed prior to each Payment Date or Special Payment Date, the Central Servicer shall deliver a written report for the Customer Rate Relief Bonds, substantially in the form attached to the Servicing Agreement (the “ <u>Central Servicer’s Certificate</u> ”) to the Issuer Entity, the Commission, the Trustee, the Collection Agents and other parties as set forth in the final Servicing Agreement, which shall include data aggregated from each Collection Agent’s Monthly Collection Agent Certificate delivered in the last six (6) months and all of the following information as to the Customer Rate Relief Bonds with respect to such Payment Date or Special Payment Date or the period since the previous Payment Date, as applicable: (i) the amount of the payment to Holders allocable to principal, if any;

⁸⁷Form to be included in Indenture.

⁸⁸ Form to be included in Collection Agreements. Form of such certificate will require Collection Agent to estimate volumetric sales for each month in year and projected collections using estimated days sales outstanding (estimated will be made using charge then currently in effect).

Business Term	Summary
	(ii) the amount of the payment to Holders allocable to interest; (iii) the aggregate Customer Rate Relief Bonds outstanding, before and after giving effect to any payments allocated to principal reported under <u>clause (a)</u> above; (iv) the difference, if any, between the amount specified in <u>clause (c)</u> above and the outstanding amount of Customer Rate Relief Bonds specified in the expected amortization schedule; (v) any other transfers and payments to be made on such Payment Date or Special Payment Date to pay all Ongoing Financing Costs, including amounts paid to or on behalf of the Trustee, the Collection Agents, the Commission and the Central Servicer; (vi) the amounts on deposit in the accounts established pursuant to the Financing Order, after giving effect to the foregoing payments; and (vii) such other information as provided for in the Servicing Agreement.
Continuing Disclosure:	Central Servicer will assist with providing information to comply with the Continuing Disclosure Agreements.
Representations and Warranties:	The Servicing Agreement shall include standard representations and warranties with respect to service agreements of its kind, as negotiated by the parties to the Servicing Agreement. In addition to the parties to the Servicing Agreement, Holders shall be entitled to rely on such representations and warranties.
Limitations on Assignment; Limitations on Resignation	• The Central Servicer will not be permitted to assign its obligations under the Servicing Agreement absent the approval of the Trustee, the Commission, and the Issuer Entity. • There will be limited ability of the Central Servicer to resign as Central Servicer subject to appointment of a successor, identified by the Commission and approved by the Issuer Entity.
Central Servicing Fee:	The Central Servicer shall receive an annual fee (the “ <u>Central Servicing Fee</u> ”), which may include certain reasonable third-party costs and expenses of the Central Servicer. No State funds will ever be used to pay or fund costs associated with the Servicing Agreement. The Central Servicing Fee and reimbursable expenses will be paid solely and exclusively by the Trustee, on behalf of the Issuer Entity, as a Bond Administrative Expense from the receipt of Customer Rate Relief Charges held outside the State Treasury. Neither the Commission nor the Authority shall ever be liable for any fee or expense incurred by the Central Servicer and the Issuer Entity’s liability is limited to the availability of funds under the Indenture to make such payment. The Central Servicer’s invoice would be approved prior to payment by the Trustee.
Central Servicer Default:	To include, but not be limited to the occurrence of one or more of the following events (a “<u>Central Servicer Default</u>”): • any failure on the part of the Central Servicer to observe or to perform in any material respect any covenants or agreements of the Central Servicer under the Servicing Agreement; or • any failure by the Central Servicer to duly perform its obligations with respect to the True-Up Adjustment or Collections Tracking in the time and manner set forth in the Servicing Agreement; or • any representation or warranty made by the Central Servicer in the Servicing Agreement shall prove to have been incorrect in any material respect when made and such misrepresentation has a material adverse effect on the Holders or other parties relying on such representation and warranty.
Remedies Upon Central Servicer Default:	Upon a Central Servicer Default, and in each and every case, so long as the Central Servicer Default shall not have been remedied in accordance with the Servicing Agreement, the Issuer Entity may request the retention of an alternate party to replace the defaulting Central Servicer, in which case such party will perform the obligations of the Central Servicer under the Servicing Agreement (as duly amended or replaced to reflect the replacement Servicer) and ensure the timely payment of the Customer Rate Relief Bonds; provided, however the rights and obligations

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Business Term	Summary
	of the existing Central Servicer under the Servicing Agreement shall to the extent practicable continue until a successor can be appointed. In the event of such Central Servicer Default and resulting request by or on behalf of the Issuer Entity, the Commission shall promptly identify potential alternate candidates to be appointed to replace the defaulting Central Servicer and cooperate with the Issuer Entity to appoint a successor Central Servicer in accordance with the terms of the Servicing Agreement. The defaulting Central Servicer shall cooperate with the successor Central Servicer, the Commission, Issuer Entity and the Trustee in effecting the termination of the responsibilities and rights of the defaulting Central Servicer under the Servicing Agreement, including the transfer to the successor Central Servicer for administration by it of all Customer Rate Relief Property Records. The foregoing shall not be exclusive, and shall be in addition to any other remedies that may be available in the event of such events of default.
Responsibilities of Commission:	Subject to the section titled “<u>Further Responsibilities</u>” below, the responsibilities of the Commission under the Servicing Agreement shall be limited to the following, and any matters directly related to the following as reasonably determined by the Commission: • In the event of (i) any failure by one or more of any Participating Gas Utility (or Successor Utility) to remit the Customer Rate Relief Charge collections to the Trustee, (ii) any failure to provide any information required under the Collection and Reporting Arrangements or the Financing Order, or (iii) any other material default by a Participating Gas Utility (or Successor Utility) under the Collection and Reporting Arrangements or the Financing Order (including any failure or delay in the remittance of proceeds), upon written request to the Commission by the Central Servicer, the Issuer Entity or the Trustee, the Commission will act promptly to enforce the obligations of the Participating Gas Utility (or Successor Utility) thereunder. • The Commission will review True-Up Letters submitted by the Central Servicer and promptly provide notice of any errors or deficiencies in such True-Up Letters in accordance with the terms of the Financing Order and Tex. Util. Code § 104.370(c). • The Commission will inform the Central Servicer of any adjustments it requires to be made to the uncollectible factor in calculating the Customer Rate Relief Charge and any adjustment thereto in order to ensure timely payment of debt service on the Customer Rate Relief Bonds and Ongoing Financing Costs. • In the event of a request to appoint a successor servicer as provided in the Servicing Agreement or a vacancy in the position of servicer, the Commission shall promptly identify potential alternate candidates to be appointed to replace the Central Servicer. • If the Central Servicer defaults on its obligation to file a True Up Adjustment Letter in accordance with the terms of the Servicing Agreement, the Servicing Agreement shall provide for certain remedies to cure such default; such remedies may include an undertaking by the Commission to promptly take all actions necessary to (i) adjust the Customer Rate Relief Charge, on behalf of the Issuing Entity and in accordance with the terms of this Financing Order, to ensure the timely payment of the Customer Rate Relief Bonds, and (ii) identify and cooperate with the Issuer Entity to appoint a successor Central Servicer.
Responsibilities of Issuer Entity:	Subject to the section titled “<u>Further Responsibilities</u>” below, the responsibilities of the Issuer Entity under the Servicing Agreement shall be limited to the following, and any matters directly related to the following as reasonably determined by the Issuer Entity: • The Issuer Entity, with the assistance of the Authority, will be responsible for negotiating the Servicing Agreement with the Central Servicer and drafting the Servicing Agreement. • In the Financing Order, the Commission has identified entities that may be engaged pursuant to the Servicing Agreement to act as the initial Central Servicer; however, the Issuer Entity,

Business Term	Summary
	with the assistance of the Authority, is responsible for procuring the initial Central Servicer from the identified candidates. • Except for the obligations of the Commission, the Issuer Entity will be responsible for administering the Servicing Agreement for the duration of its terms. • The Issuer Entity shall ensure the timely payment of the Central Servicer Fee in accordance with the terms of this <u>Exhibit 5</u>. • The Issuer Entity will also assist the Trustee as may be requested from time to time in order to ensure the Central Servicer Fee is paid in accordance with the terms of the Servicing Agreement. The Issuer Entity will ensure compliance with the provisions set forth in the section below entitled "<u>Amendment</u>".
Further Responsibilities:	Any responsibility not otherwise addressed in this <u>Exhibit 5</u> to the Financing Order or in the Financing Order shall be resolved by mutual agreement during the negotiations of the definitive documentation.
State Pledge:	The State of Texas, including the Commission and the Authority has pledged for the benefit and protection of the financing parties (as defined in H.B. 1520) and the Participating Gas Utilities that the State of Texas will not take or permit any action that would impair the value of Customer Rate Relief Property, or, except for the true-up expressly permitted under H.B. 1520, reduce, alter, or impair the Customer Rate Relief Charges to be imposed, collected and remitted to financing parties, until the principal, interest and any other charges incurred and contracts to be performed in connection with the Customer Rate Relief Bonds have been paid and performed in full.
Assignment by the Commission or the Issuer Entity:	Except for collateral assignment by the Issuer Entity to the Trustee for the benefit of the Holders in connection with the issuance of the Customer Rate Relief Bonds (the " <u>Collateral Assignment</u> "), neither the Issuer Entity nor the Commission may assign or otherwise transfer, in whole or in part, its rights, obligations and/or interests under the Servicing Agreement unless such transfer is consented to by the non-assigning parties. Notwithstanding anything to the contrary herein, the Collateral Assignment shall be on terms customary for a transaction of this type. For the avoidance of doubt, the Collateral Assignment shall not relieve the Issuer Entity from any of its obligations, duties or responsibilities under the Servicing Agreement.
Amendment:	The Servicing Agreement may be amended with the approval of all of the parties to the Servicing Agreement. It is understood that the Indenture may provide for certain restrictions on the Issuer Entity's rights to agree to amendments, waivers, or other modifications to the Servicing Agreement.
Other Provisions:	• The Servicing Agreement may include provisions, as necessary, to give effect to the Remaining Balances Provisions, as determined by the Issuer Entity and reasonably satisfactory to the Commission. • The Trustee and the Holders shall be third party beneficiaries of the Servicing Agreement with the right to enforce the Servicing Agreement in accordance with its terms and the Indenture for the Customer Rate Relief Bonds. • The Servicing Agreement shall include provisions, as necessary, to achieve the highest possible ratings on the Customer Rate Relief Bonds, as determined by the Issuer Entity and reasonably satisfactory to the Commission acting through the Designated Representative.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Investigation into Atmos)
Energy Corporation Regarding the February)
2021 Winter Weather Events, as Contemplated) Docket No. 21-ATMG-333-GIG
by Docket No. 21-GIMX-303-MIS)

JOINT MOTION TO APPROVE SETTLEMENT AGREEMENT

Atmos Energy Corporation ("Atmos Energy"), the Staff of the State Corporation Commission of the State of Kansas ("Staff" and "Commission" respectively) and the Citizens' Utility Ratepayer Board ("CURB") (collectively Joint Movants"), pursuant to K.A.R. 82-1-230a, request the Commission issue an Order approving the Settlement Agreement ("Agreement") attached hereto as Exhibit A. In support of this Motion, the Joint Movants state and allege as follows:

1. On February 15, 2021, the Commission issued an Emergency Order ("Emergency Order") relating to the stress on utility and natural gas providers caused by the sub-zero temperatures which were causing increased energy demand and natural gas supply constraints throughout Kansas and wholesale natural gas prices to increases from 10 to 100 times higher than normal ("Winter Event").¹ The Commission stated that Kansas utilities were facing potential reliability issues related to the prolonged arctic temperatures and, therefore, it intended to exercise its emergency powers pursuant to K.S.A. 77-536(a).² The Commission directed all jurisdictional natural gas and electric utilities to coordinate efforts and take all reasonably feasible, lawful, and appropriate actions to ensure

¹Emergency Order, Docket No. 21-GIMX-303-MIS, In the Matter of Record Natural Gas Prices and Potential System Reliability Issues from Unprecedented and Sustained Cold Weather, February 15, 2021, page 1, paragraph 1 ("Emergency Order").

²*Id.*, pages 1-2, paragraph 2.

adequate transportation and electricity to interconnected, non-jurisdictional Kansas utilities.³ The Commission ordered the utilities to do everything necessary to ensure natural gas and electricity service continue to be provided to their customers in Kansas.⁴ The Commission authorized every electric and natural gas utility to defer extraordinary costs relating to the Winter Event to a regulatory asset account.⁵ The Commission indicated that deferred costs may also include carrying costs at the utility's weighted average cost of capital ("WACC").⁶

2. On March 9, 2021, the Commission opened Docket No. 21-ATMG-333-GIG ("333 Docket") to investigate the effects of the Winter Event on Atmos Energy and its customers.⁷ The Commission intended to analyze any extraordinary costs incurred during the Winter Event.⁸ The Commission ordered Atmos Energy to file a plan to minimize the financial impact of the Winter Event on customers.⁹

3. On September 14, 2021, Atmos Energy submitted its plan to minimize the financial impact of the Winter Event on customers in the 333 Docket ("Financial Plan").¹⁰ Atmos Energy filed pre-filed direct testimony and exhibits in support of its Financial Plan prepared by Barton W.

³*Id.*, page 2, paragraph 3.

⁴*Id.*

⁵*Id.*, page 2, paragraph 4.

⁶*Id.*

⁷Order Adopting Staff's R&R to Open Company Specific Investigations, Docket No. 21-ATMG-333-GIG, March 9, 2021, page 4, paragraph 10.

⁸*Id.*, page 2, paragraph 3.

⁹*Id.*, page 5, paragraph 10.

¹⁰Atmos Energy's Plan to Minimize Financial Effects of Cold Weather Event, Docket No. 21-ATMG-333-GIG, September 14, 2021 ("Financial Plan").

Armstrong, Rob R. Leivo, Kenneth M. Malter, Kathleen R. Ocanas, and Jason L. Schneider.¹¹ Under the Financial Plan, Atmos Energy would apply for a Financing Order in a separate docket pursuant to the applicable provisions contained in the Utility Financing and Securitization Act passed by the Kansas Legislature in 2021 ("Act").¹² The Financing Order would authorize the issuance of Securitized Utility Tariff Bonds to finance the Qualified Extraordinary Costs (as defined by the Act) incurred by Atmos Energy as a result of the 2021 winter weather event ("Winter Event") in order to minimize the financial impact on the Company and its customers.

The other main elements of the Plan included the: (1) identification and quantification of the Qualified Extraordinary Costs to be financed under the Plan; (2) range of time periods to be used to collect the Qualified Extraordinary Costs from customers under a Securitized Utility Tariff Charge that would be the same as the term of the Securitized Utility Tariff Bonds; (3) method of allocating the Qualified Extraordinary Costs among sales classes and the use of a fixed monthly Securitized Utility Tariff Charge to recover the Qualified Extraordinary Costs from customers; and (4) future rate making process to reconcile any differences between the Securitized Utility Tariff Costs financed by the Securitized Utility Tariff Bonds and the final Securitized Utility Tariff Costs incurred by Atmos Energy relating to the Winter Event. The reconciliation process would include, but is not limited to, Atmos Energy crediting customers for: (i) the net penalty amounts recovered by Atmos Energy after the Securitized Utility Tariff Bonds have been issued; (ii) the ultimate resolution of the net disputed purchased gas cost invoice amounts, if any, recovered or received by Atmos Energy after the

¹¹Direct Testimony of Barton W. Armstrong, Direct Testimony of Rob R. Leivo, Direct Testimony of Kenneth M. Malter, Direct Testimony of Kathleen R. Ocanas, and Direct Testimony of Jason L. Schneider in Support of Plan, Docket No. 21-ATMG-333-GIG, September 14, 2021.

¹²Kansas Utility Financing and Securitization Act, Senate Substitution for House Bill No. 2072, published in Kansas Register April 22, 2021, sos.ks.gov/publications/register/volume-40/issue%2016/04-22-21-49065.html. Capitalized terms contained in this filing have the meanings set forth in new Section 1(b) of the Act.

Securitized Utility Tariff Bonds have been issued and (iii) any subsequent federal or state governmental relief in the form of profit disgorgement, civil suit relief, market manipulation findings, etc., recovered by Atmos Energy after the Securitized Utility Tariff Bonds have been issued. To the extent that Atmos Energy would need a waiver of any of its existing tariffs in order to implement its Plan, including its Purchased Gas Adjustment ("PGA") tariff, the Company requests approval of said waivers.

4. On November 4, 2021, the Commission issued an order establishing a procedural schedule for the Financial Plan.¹³

5. The Commission granted intervention to the following parties (collectively including Atmos Energy, "Parties") in the 333 Docket:

- (a) State of Kansas, ex rel., Derek Schmidt, Attorney General ("AG"); and
- (b) CURB.¹⁴

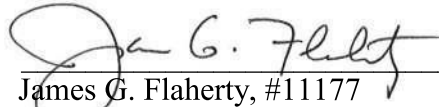
6. All of the Parties participated in a technical/settlement conference held on January 27, 2022. Settlement discussions occurred through February 3, 2022. The Agreement provided to the Commission by the Joint Movants was reached on February 8, 2022, and filed on February 9, 2022. The Joint Movants plan to file testimony in support of the Agreement. The AG indicated it does not oppose the settlement.

7. The Joint Movants believe that the Agreement represents a reasonable and fair resolution of this matter and that the terms contained therein are in the public interest.

¹³Order Establishing Procedural Schedule for the Financial Plan, Docket No. 21-ATMG-333-GIG filed October 28, 2021. The Commission issued an order modifying the procedural schedule for the Financial Plan on January 4, 2022.

¹⁴Order Granting Petition to Intervene of the Office of Kansas Attorney General, Docket No. 21-ATMG-333-GIG filed July 27, 2021; CURB was granted intervention in this 333 Docket by Order dated March 9, 2021, Ordering Paragraph B in Docket No. 21-GIMX-303-MIS.

WHEREFORE, for the reasons set forth herein, Atmos Energy, Staff and CURB request this Joint Motion be granted and that the Agreement attached hereto be approved.



James G. Flaherty, #11177
ANDERSON & BYRD, LLP
216 S. Hickory ~ P.O. Box 17
Ottawa, Kansas 66067
(785) 242-1234, telephone
(785) 242-1279, facsimile
jflaherty@andersonbyrd.com

Kevin C. Frank, Senior Attorney
Atmos Energy Corporation
P.O. Box 650205
Dallas, TX 75265-0205
(214) 906-9827, telephone
(214) 550-6836, facsimile
kevin.frank@atmosenergy.com
Attorneys for Atmos Energy Corporation

/s/ Terri J. Pemberton

Terri J. Pemberton, #23297
Chief Litigation Counsel
Walker A. Hendrix, #08835
Litigation Counsel
Kansas Corporation Commission
1500 S. W. Arrowhead Road
Topeka, Kansas 66604
t.pemberton@kcc.ks.gov
m.neeley@kcc.ks.gov
For Commission Staff

/s/ Todd E. Love

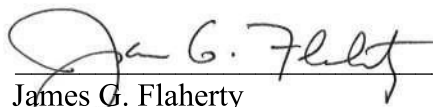
David W. Nickel, #11170
Todd E. Love, #13445
Joseph R. Astrab #26414
Citizens' Utility Ratepayer Board
1500 SW Arrowhead Road
Topeka, KS 66604
(785) 271-3200
(785) 271-3116 Fax
d.nickel@curb.kansas.gov
t.love@curb.kansas.gov
j.astrab@curb.kansas.gov
Attorneys for CURB

VERIFICATION

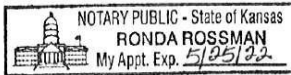
STATE OF KANSAS
COUNTY OF FRANKLIN, ss:

James G. Flaherty, of lawful age, being first duly sworn on oath, states:

That he is the attorney for Atmos Energy Corporation named in the foregoing Joint Motion to Approve Settlement Agreement and is duly authorized to make this affidavit; that he has read the foregoing and knows the contents thereof; and that the facts set forth therein are true and correct.


James G. Flaherty

SUBSCRIBED AND SWORN to before me this 9th day of February, 2022.





Notary Public

Appointment/Commission Expires:

CERTIFICATE OF SERVICE

I hereby certify that a copy of the above and foregoing was sent via electronic mail this 9th day of February, 2022, addressed to:

Shelly M. Bass
shelly.bass@atmosenergy.com

Kathleen R. Ocanas
Kathleen.Ocanas@atmosenergy.com

Joseph R. Astrab
j.astrab@curb.kansas.gov

Todd E. Love
t.love@curb.kansas.gov

David W. Nickel
d.nickel@curb.kansas.gov

Shonda Rabb
s.rabb@curb.kansas.gov

Della Smith
d.smith@curb.kansas.gov

Melanie S. Jack
Melanie.Jack@ag.ks.gov

Derek Schmidt
Derek.Schmidt@ag.ks.gov

Brian G. Fedotin
b.fedotin@kcc.ks.gov

Walker A. Hendrix
w.hendrix@kcc.ks.gov

Terri J. Pemberton
t.pemberton@kcc.ks.gov

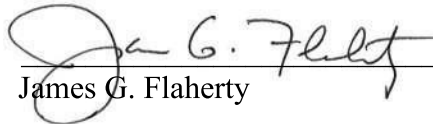

James G. Flaherty

EXHIBIT A

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Investigation into Atmos Energy)
Corporation Regarding the February 2021 Winter)
Weather Events, as Contemplated by Docket No.) Docket No. 21-ATMG-333-GIG
21-GIMX-303-MIS)

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is entered into between and among Atmos Energy Corporation ("Atmos Energy"), the Staff of the State Corporation Commission of the State of Kansas ("Staff" and "Commission," respectively), and the Citizens' Utility Ratepayer Board ("CURB"), (collectively Joint Movants"). This Agreement is being submitted to the Commission for approval pursuant to K.A.R. 82-1-230a.

I. INTRODUCTION: PROCEDURAL HISTORY OF DOCKETS

1. On February 15, 2021, the Commission issued an Emergency Order ("Emergency Order") relating to the stress on utility and natural gas providers caused by the sub-zero temperatures which were causing increased energy demand and natural gas supply constraints throughout Kansas and wholesale natural gas prices to increases from 10 to 100 times higher than normal ("Winter Event").¹ The Commission stated that Kansas utilities were facing potential reliability issues related to the prolonged arctic temperatures and, therefore, it intended to exercise its emergency powers pursuant to K.S.A. 77-536(a).² The Commission directed all jurisdictional natural gas and electric utilities to coordinate efforts and take all reasonably feasible, lawful, and appropriate actions

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²*Id.*, pages 1-2, paragraph 2.

to ensure adequate transportation and electricity to interconnected, non-jurisdictional Kansas utilities.³ The Commission ordered the utilities to do everything necessary to ensure natural gas and electricity service continue to be provided to their customers in Kansas.⁴ The Commission authorized every electric and natural gas utility to defer extraordinary costs relating to the Winter Event to a regulatory asset account.⁵ The Commission indicated that deferred costs may also include carrying costs at the utility's weighted average cost of capital ("WACC").⁶

2. On March 9, 2021, the Commission opened Docket No. 21-ATMG-333-GIG ("333 Docket") to investigate the effects of the Winter Event on Atmos Energy and its customers.⁷ The Commission intended to analyze any extraordinary costs incurred during the Winter Event.⁸ The Commission ordered Atmos Energy to file a plan to minimize the financial impact of the Winter Event on customers.⁹

3. On September 14, 2021, Atmos Energy submitted its plan to minimize the financial impact of the Winter Event on customers in the 333 Docket ("Financial Plan").¹⁰ Atmos Energy filed pre-filed direct testimony and exhibits in support of its Financial Plan prepared by Barton W.

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⁹*Id.*, page 5, paragraph 10

¹⁰Atmos Energy's Plan to Minimize Financial Effects of Cold Weather Event, Docket No. 21-ATMG-333-GIG, September 14, 2021 ("Financial Plan").

Armstrong, Rob R. Leivo, Kenneth M. Malter, Kathleen R. Ocanas, and Jason L. Schneider.¹¹ Under the Financial Plan, Atmos Energy would apply for a Financing Order in a separate docket pursuant to the applicable provisions contained in the Utility Financing and Securitization Act passed by the Kansas Legislature in 2021 ("Act").¹² The Financing Order would authorize the issuance of Securitized Utility Tariff Bonds to finance the Qualified Extraordinary Costs (as defined by the Act) incurred by Atmos Energy as a result of the 2021 winter weather event ("Winter Event") in order to minimize the financial impact on the Company and its customers.

The other main elements of the Plan included the: (1) identification and quantification of the Qualified Extraordinary Costs to be financed under the Plan; (2) range of time periods to be used to collect the Qualified Extraordinary Costs from customers under a Securitized Utility Tariff Charge that would be the same as the term of the Securitized Utility Tariff Bonds; (3) method of allocating the Qualified Extraordinary Costs among sales classes and the use of a fixed monthly Securitized Utility Tariff Charge to recover the Qualified Extraordinary Costs from customers; and (4) future rate-making process to reconcile any differences between the Securitized Utility Tariff Costs financed by the Securitized Utility Tariff Bonds and the final Securitized Utility Tariff Costs incurred by Atmos Energy relating to the Winter Event. The reconciliation process would include, but is not limited to, Atmos Energy crediting customers for: (i) the net penalty amounts recovered by Atmos Energy after the Securitized Utility Tariff Bonds have been issued; (ii) the ultimate

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¹²Kansas Utility Financing and Securitization Act, Senate Substitution for House Bill No. 2072, published in Kansas Register April 22, 2021, sos.ks.gov/publications/register/volume-40/issue%2016/04-22-21-49065.html. Capitalized terms contained in this filing have the meanings set forth in new Section 1(b) of the Act.

resolution of the net disputed purchased gas cost invoice amounts, if any, recovered or received by Atmos Energy after the Securitized Utility Tariff Bonds have been issued and (iii) any subsequent federal or state governmental relief in the form of profit disgorgement, civil suit relief, market manipulation findings, etc., recovered by Atmos Energy after the Securitized Utility Tariff Bonds have been issued. To the extent that Atmos Energy would need a waiver of any of its existing tariffs in order to implement its Plan, including its Purchased Gas Adjustment ("PGA") tariff, the Company requests approval of said waivers.

4. On November 4, 2021, the Commission issued an order establishing a procedural schedule for the Financial Plan.¹³

5. The Commission granted intervention to the following parties (collectively including Atmos Energy, "Parties") in the 333 Docket:

- (a) State of Kansas, *ex rel.*, Derek Schmidt, Attorney General ("AG"); and
- (b) CURB.¹⁴

6. All of the Parties participated in a technical/settlement conference held on January 27, 2022. Settlement discussions occurred through February 3, 2022. The Agreement provided to the Commission by the Joint Movants was reached on February 8, 2022, and filed on February 9, 2022. The Joint Movants plan to file testimony in support of the Agreement. The AG indicated it

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¹⁴Order Granting Petition to Intervene of the Office of Kansas Attorney General, Docket No. 21-ATMG-333-GIG filed July 27, 2021; CURB was granted intervention in this 333 Docket by Order dated March 9, 2021, Ordering Paragraph B in Docket No. 21-GIMX-303-MIS.

does not oppose the settlement.

7. The Joint Movants believe that the Agreement represents a reasonable and fair resolution of this matter and that the terms contained therein are in the public interest.

II. SETTLEMENT PROVISIONS

8. Subject to the true-up and verification requirement set forth in this paragraph 8, the Joint Movants agree that the \$102,517,847 in Qualified Extraordinary Costs incurred by Atmos Energy during the Winter Event were prudently incurred by the utility and that Atmos Energy shall be allowed to recover said costs pursuant to the terms contained in this Agreement ("Qualified Extraordinary Costs"). Attached as Appendix A to this Agreement is a list of Qualified Extraordinary Costs and the amount of those costs. The Qualified Extraordinary Costs shall be true-up and verified as part of Atmos Energy's separate filing to obtain a securitization order under the Act.

9. In order to minimize the financial impact to Atmos Energy's customers of the Qualified Extraordinary Costs incurred as a result of the Winter Event, Atmos Energy shall apply for a Financing Order in a separate docket pursuant to the applicable provisions contained in the Act. The Financing Order would authorize the issuance of Securitized Utility Tariff Bonds to finance the Qualified Extraordinary Costs incurred by Atmos Energy as a result of the Winter Event, which are set forth in Appendix A to this Agreement.

10. Atmos Energy shall also be permitted to recover carrying charges on the Qualified Extraordinary Costs. However, instead of incorporating the Commission authorized calculation of a carrying cost based on Atmos Energy's weighted average cost of capital of 8.3960%, Atmos Energy has agreed to lower the carrying charge rate to 2.0% on those Qualified Extraordinary Costs

incurred between the time the costs were incurred until the Securitized Utility Bonds are issued and Atmos Energy begins to charge customers a Securitized Utility Tariff Charge. This reduction in the carrying charges results in reducing the carrying charges from approximately \$9.47 million over the above referenced period to approximately \$2.56 million, producing a savings of \$7.21 million.

11. Atmos Energy agrees to defer determination by the Commission on items relating to the Securitized Utility Tariff Bonds, such as the term of the bonds and how the Securitized Utility Tariff Charge will be recovered from Atmos Energy's sales customers to Atmos Energy's separate filing for approval of its issuance of Securitized Utility Tariff Bonds.

12. Any reconciliation proposal included by Atmos Energy in its separate filing for approval to issue the Securitized Utility Tariff Bonds shall consider both the deferred tax liability associated with the extraordinary gas cost recoveries, as well as the corresponding and offsetting deferred tax asset associated with the net operating loss carryforward created by the extraordinary costs.¹⁵

13. If Atmos Energy receives or recovers any payments as a result of any subsequent federal or state governmental relief in the form of profit disgorgement, civil suit relief, market manipulation findings, etc., resulting from the Winter Event, it shall pass those payments on to its customers through its PGA, even if those payments may be received or recovered after the expiration of the Securitized Utility Tariff Charge.

14. Provided that such would be allowed under the Act, any Atmos Energy sales customer, who intends on becoming a Atmos Energy's transportation customer during the period in

¹⁵While the deferred tax liability and deferred tax asset currently net to zero rate base impact, the deferred tax asset may reverse over the time period of rate recovery and therefore there would be a net rate base reduction associated with these deferred taxes.

which the Securitized Utility Tariff Charge is being recovered shall be required to pay Atmos Energy a conversion fee prior to becoming a transportation customer. The conversion fee owed by the customer shall be based on the present value of the expected charges the customer would have paid as a sales customer over the remaining period in which the Securitized Utility Tariff Charge is being recovered. This conversion fee will be credited to Atmos Energy's other sales customers once a year through the PGA.

15. All penalty payments received by Atmos Energy from marketers or transport customers (identified in Appendix B to this Agreement) that are received prior to the filing of the separate application for a Financing Order will be used by Atmos Energy to reduce the Qualified Extraordinary Costs to be recovered using the Securitized Utility Bonds. All penalty amounts received after that filing will be credited by Atmos Energy to Atmos Energy's sales customers through the PGA/ACA on an annual basis.

16. Atmos Energy agrees to reduce the carrying charge rate applied to its Extraordinary Gas Costs to the 2.0% carry charge rate.

17. Atmos Energy agrees to meet with Staff and CURB to discuss programs that it has implemented in other states to assist low-income customers to determine if those programs could be used to assist low-income customers in Kansas.

18. Nothing in this Agreement is intended to impinge or restrict, in any manner, the exercise by the Commission of any statutory right, including the right of access to information, and any statutory obligation, including the obligation to ensure that Atmos Energy is providing efficient and sufficient service at just and reasonable rates.

19. The Joint Movants shall have the right to present pre filed testimony in support of

this Agreement. Such testimony shall be filed formally in the docket and presented by witnesses at a hearing on this Agreement. Such testimony shall be filed as required by the procedural schedule, or any modification to the procedural schedule filed in this docket.

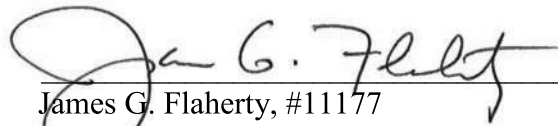
20. This Agreement represents a negotiated settlement that fully resolves all of the issues in this docket among the Joint Movants. The Joint Movants represent that the terms of this Agreement constitute a fair and reasonable resolution of the issues addressed herein. Except as specified herein, the Joint Movants shall not be prejudiced, bound by, or in any way affected by the terms of this Agreement (a) in any future proceeding; (b) in any proceeding currently pending under a separate docket; and/or (c) in this proceeding should the Commission decide not to approve this Agreement in the instant proceeding. If the Commission accepts this Agreement in its entirety and incorporates the same into a final order without material modification, the Joint Movants shall be bound by its terms and the Commission's order incorporating its terms as to all issues addressed herein and in accordance with the terms hereof, and will not appeal the Commission's order on these issues provided that Commission approval of this Agreement shall not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

21. The provisions of this Agreement have resulted from negotiations among the Joint Movants and are interdependent. In the event that the Commission does not approve and adopt the terms of this Agreement in total, the Agreement shall be voidable and no party hereto shall be bound, prejudiced, or in any way affected by any of the agreements or provisions hereof. Further, in such event, this Agreement shall be considered privileged and not admissible in evidence or made a part of the record in any proceeding.

22. To the extent this Agreement provides for information, documents or other data to

be furnished to the Commission or Staff, such information, documents or data shall be filed with the Commission and a copy served upon the Commission's Director of Utilities. Such information, documents, or data shall be marked and identified with the docket number of this proceeding.

IN WITNESS WHEREOF, the Joint Movants have executed and approved this Stipulated Settlement Agreement, effective as of the 9th day February 2022, by subscribing their signatures below.



James G. Flaherty, #11177
ANDERSON & BYRD, LLP
216 S. Hickory ~ P.O. Box 17
Ottawa, Kansas 66067
(785) 242-1234, telephone
(785) 242-1279, facsimile
jflaherty@andersonbyrd.com

Kevin C. Frank
Senior Attorney
Atmos Energy Corporation
P.O. Box 650205
Dallas, TX 75265-0205
(214) 906-9827, telephone
(214) 550-6836, facsimile
kevin.frank@atmosenergy.com

Attorney for Atmos Energy Corporation

/s/ Terri J. Pemberton

Terri J. Pemberton, #23297
Chief Litigation Counsel
Walker A. Hendrix, #08835
Litigation Counsel
Kansas Corporation Commission
1500 S. W. Arrowhead Road
Topeka, Kansas 66604
t.pemberton@kcc.ks.gov
w.hendrix@kcc.ks.gov
For Commission Staff

/s/ Todd E. Love

David W. Nickel, #11170
Todd E. Love, #13445
Joseph R. Astrab #26414
Citizens' Utility Ratepayer Board
1500 SW Arrowhead Road
Topeka, KS 66604
(785) 271-3200
(785) 271-3116 Fax
d.nickel@curb.kansas.gov
t.love@curb.kansas.gov
j.astrab@curb.kansas.gov
Attorneys for CURB

APPENDIX A

LIST OF QUALIFIED EXTRAORDINARY COSTS

DESCRIPTION	AMOUNT
Gas Costs	\$76,652,625
Carrying Costs – at 2% through 8/31/2022	\$2,256,994
KGS Penalties From 21-KGSG-332-GIG	\$9,559,372
Financing Fees Relating to Securitization	\$13,230,139
Legal/Consulting Fees (excluding financing fees) Relating to this Docket and Securitization	\$818,717
Total Extraordinary Costs	\$102,517,847

APPENDIX B

Atmos Energy Corporation
Docket No. 21-ATMG-333-GIG
(2021 February Weather Event)
Penalty Flow Through

Marketer	Usage (MMBTu)	Net Amount
* *	1500.300	\$211,487.62
* *	827.564	\$123,033.64
Total	2327.86	\$334,521.25

Decision No. R21-0720

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0186G

IN THE MATTER OF THE APPLICATION OF ATMOS ENERGY CORPORATION FOR
AN ORDER AUTHORIZING IT TO RECOVER THE COSTS ASSOCIATED WITH THE
FEBRUARY 2021 EXTREME WEATHER EVENT THROUGH THE COMPANY’S GAS
COST ADJUSTMENT MECHANISM.

**RECOMMENDED DECISION OF
ADMINISTRATIVE LAW JUDGE
ROBERT I. GARVEY
GRANTING MOTION TO APPROVE
SETTLEMENT AND GRANTING APPLICATION**

Mailed Date: November 12, 2021

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I. STATEMENT

1. The Public Utilities Commission (the Commission) opened Proceeding No. 21M-0130EG by Decision No. C21-0179, issued on March 23, 2021, to commence its consideration of the impacts of the extreme weather event on the revenue requirements and rates

of Colorado's investor-owned electric and natural gas utilities including Atmos Energy Corporation (Atmos). The Commission prohibited Atmos and the other utilities from addressing the recovery of the extraordinary costs of the February extreme weather event through the normal course of the implementation of their Gas Cost Adjustment rate mechanisms and instead directed the utilities to isolate the extraordinary costs associated with the February extreme weather for the purpose of proposing discrete methods for cost recovery in separate, utility-specific proceedings.

2. By Decision No. C21-0261, issued on April 30, 2021 in Proceeding No. 21M-0130EG, the Commission permitted Atmos and the other Colorado utilities to file applications to address the recovery of the costs incurred as a result of the February 2021 weather event from their customers through rates. The Commission required such application filings to include certain information as set forth in that decision.

3. On May 14, 2021, Atmos submitted the Application for consideration by the Commission. Atmos filed the Application in accordance with Decision No. C21-0261.

4. On May 20, 2021, the Colorado Office of the Consumer Utility Advocate (UCA) filed its Notice of Intervention of Right, Request for Hearing and Entry of Appearance. The UCA listed a series of issues they wished to investigate.

5. On May 20, 2021, the Colorado Public Utilities Commission Trial Staff filed a Notice of Intervention as of Right, Entry of Appearance, Notice Pursuant to Rule 1007(a), and Request for Hearing. The procedural history of this proceeding is set out in previous Decisions and is repeated here as necessary to put this Decision in context.

6. On June 14, 2021, the Colorado Energy Office filed its Notice of Intervention by Right.

7. On June 30, 2021, the Commission deemed the Application complete and referred it to the undersigned Administrative Law Judge (ALJ) for disposition.

8. On July 12, 2021, by Decision No. R21-0409-I the ALJ scheduled this matter for a prehearing conference for July 29, 2021. At the prehearing conference, an evidentiary hearing was scheduled for November 8, 2021 through November 10, 2021

9. On October 1, 2021, Atmos filed its Motion for Summary Judgement.

10. On October 14, 2021, Atmos filed its Unopposed Motion to Modify Procedural Schedule and Response Deadline.

11. On October 18, 2021, by Decision No. R21-0647-I the Unopposed Motion to Modify Procedural Schedule and Response Deadline was granted.

12. On October 21, 2021, Atmos filed its Unopposed Motion for Approval of Stipulation and Settlement Agreement and Notice of Withdrawal of Motion for Summary Judgment.

13. On October 29, 2021, Atmos filed testimony in support of the Settlement Agreement.

14. On November 2, 2021, by Decision No. R21-0684-I the remaining procedural schedule was vacated.

II. DISCUSSION

A. Terms of Settlement Agreement

15. The Settlement Agreement, attached to this Decision as Attachment A, explains that the Settling Parties have negotiated a resolution of all disputed issues in this proceeding. The Settling Parties assert that the Settlement Agreement represents a compromise in the positions of

all Settling Parties and has been negotiated as a comprehensive settlement. Further, the Settling Parties contend that the Settlement Agreement is in the public interest and supported by the Settling Parties' testimony. *See* Attachment A at pp. 8 and 9.

16. The Settlement Agreement represents the result of settlement negotiations by the Settling Parties wherein the Settling Parties agree that the Commission should approve Atmos' application for recovery of the Extraordinary Gas Cost (EGC) incurred during the extreme weather event that took place between February 13 through 19, 2021. *Id.* at p. 9.

17. The Settling parties Agree that Atmos' Motion for Summary Judgment be withdrawn; that there be an establishment of an Extraordinary Gas Cost Recovery Rider (EGCRR); and a near-term and long-term conservation messaging meeting by all Settling Parties be scheduled. *Id.* At p. 3.

B. Approval of Establishment of New Extraordinary Gas Cost Recovery Rider

18. The Settling Parties stipulate that the EGCRR will recover the EGC through separate volumetric rates for each of the Company's rate divisions that will be implemented by an advice letter filed simultaneously with a proposed tariff change to remove the unprotected amounts of Excess Differed Income Tax liabilities from the rate rider currently returning both protected and unprotected Deferred Income Tax to customers. *Id.*

19. The Settling Parties agree that the \$23,549.609 in EGC will be offset by the regulatory liabilities associated with the differences between actual FAS 87 and FAS 87 pension expenses in base rates established in Decision No. C18-0311, at ¶75, in Proceeding No. 17AL-0429G issued May 3, 2018.

20. The Settling Parties stipulate that the EGCRR will be set to collect the net gas costs over a 24-month period for the North rate division and a 12-month period for the Southeast

and Southwest rate divisions. The Settling Parties stipulate on the estimated rates to be collected from Atmos' customers. *See* Attachment A at pp. 4 and 5.

21. The Settling Parties agree that the EGCCR recovery will commence within 45 days from the approval of the Settlement Agreement by the Commission. *Id.* at p. 5.

22. The Settling Parties agree that no interest or carry costs will be applied to the EGC through the EGCCR. *Id.*

23. The Settling Parties agree that recipients of Low-Income Energy Assistance; Percentage of Income Payment Programs (PIPP) and irrigation customers will be exempt from rate changes from the EGCCR. *Id.*

24. The Settling Parties agree that Atmos will attach onserts along the service bills sent out to residential customers. The onserts will provide notice of the EGCCR and PIPP eligibility the month prior to the EGCCR going into effect. That information will also be distributed via email to those customers for whom Atmos has email addresses. *Id.*

25. The Settling Parties agree that the Settlement Agreement will not go into effect until the Commission issues a final written decision that approves of all the stipulations above. *Id.* at p. 9.

C. Testimony in Support of the Settlement

26. On October 29, 2021, Atmos filed the testimony of Joe T. Christian and Jared N. Geiger in support of the Settlement Agreement. The testimony establishes the stipulated recovery calculation methods for the EGCCR; implementation procedures for the EGCCR; expected results from the implementation of the EGCCR; timelines of implementation of the EGCCR; protection of low-income customers under the EGCCR exemptions and that the approval of the Settlement Agreement is in the public interest.

27. Mr. Christian describes the regulatory liabilities used to offset the extraordinary gas costs and explains the calculations and support for the proposed EGCR.

28. Mr. Geiger explains the elements of the Unanimous Comprehensive Stipulation and Settlement Agreement. He explains the agreed upon method for recovering the extraordinary gas costs incurred to serve customers from February 13 through 19, 2021 and how the Settlement applies regulatory liabilities to reduce the balance of costs to be recovered, shortens the recovery period, recovers the costs through separate riders, eliminates carrying costs on the balance, and insulates low-income customers from the new rate riders.

III. FINDINGS AND CONCLUSIONS

29. The Commission has jurisdiction over the subject matter of this proceeding, pursuant to §§ 40-1-103(1), 40-3-102, and 40-6-111, C.R.S., and over the Parties.

30. The parties have the burden of proving by a preponderance of the evidence that the Settlement Agreement is just and reasonable. In reviewing the terms of the Settlement Agreement, the undersigned applied the Commission's direction and policy with respect to reviews of settlement agreements as found in, *e.g.*, Decision No. C06-0259 in Proceeding No. 05S-264G issued March 20, 2006.

31. The Commission has an independent duty to determine matters that are within the public interest. *See, Caldwell v. Public Utilities Commission*, 692 P.2d 1085, 1089 (Colo. 1984).

32. The undersigned has reviewed the Unopposed Joint Motion for Approval of Stipulation and Settlement Agreement filed by Atmos; the Settlement Testimony filed by Atmos, and the recitations of the Settling Parties in both the Joint Motion and Settlement Agreement. The undersigned has duly considered the positions of all parties in this matter.

33. Based on a review of the entire record, the undersigned finds that approval of the Application filed in this proceeding is consistent with the Settlement Agreement and the proposed EGCR plan is in the public interest.

34. The ALJ further finds that the parties have established by a preponderance of the evidence that the Settlement Agreement is just, reasonable, and should be accepted by the Commission.

IV. ORDER

A. The Commission Orders That:

1. The Motion for Approval of Stipulation and Settlement Agreement filed on October 21, 2021, is granted, consistent with the discussion above.

2. The Stipulation and Settlement Agreement filed by Atmos Energy Corporation on October 21, 2021, and attached to this Decision as Attachment A, is approved, consistent with the discussion above.

3. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision shall be served upon the parties, who may file exceptions to it.

a) If no exceptions are filed within 20 days after service or within any extended period of time authorized, or unless the decision is stayed by the Commission upon its own motion, the recommended decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.

b) If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set

out by the administrative law judge and the parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

4. If exceptions to this Decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

(S E A L)



ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ROBERT I. GARVEY

Administrative Law Judge

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

IN THE MATTER OF THE APPLICATION
OF ATMOS ENERGY CORPORATION
FOR AN ORDER AUTHORIZING IT TO
RECOVER THE COSTS ASSOCIATED
WITH THE FEBRUARY 2021 EXTREME
WEATHER EVENT THROUGH THE
COMPANY'S GAS COST ADJUSTMENT
MECHANISM.

Proceeding No. 21A-0186G

**COMPREHENSIVE AND UNCONTESTED STIPULATION AND SETTLEMENT
AGREEMENT**

This Stipulation and Settlement Agreement ("Stipulation") is entered into by and between Atmos Energy Corporation ("Atmos Energy"), Trial Staff of the Colorado Public Utilities Commission ("Staff"), the Colorado Office of Utility Consumer Advocate ("UCA"), and the Colorado Energy Office ("CEO") (each a "Settling Party" and collectively the "Settling Parties") to resolve all issues which were or could have been raised regarding Atmos Energy's application to recover approximately \$23.55 million of extraordinary gas costs ("EGC") incurred during the extreme weather event on February 13-19, 2021 (the "Extreme Weather Event").

Procedural Background

1. On May 14, 2021, Atmos Energy initiated this proceeding by filing a verified application to recover the EGC incurred to meet customer demands during the Extreme Weather Event. Staff, the UCA, and CEO subsequently intervened and are the only other parties to this proceeding.

2. On July 12, 2021, Administrative Law Judge Garvey issued Decision No. R21-0409-I, extending the time for a Commission decision regarding the Company's application by 130 days and setting a prehearing conference.

3. Following the prehearing conference on July 29, 2021, ALJ Garvey issued Decision No. R21-0479-I which, among other things, adopted the procedural schedule proposed by the parties and scheduled a public comment hearing regarding the Company's application.

4. Pursuant to the procedural schedule adopted in Decision No. R21-0479-I, Staff, the UCA, and CEO filed answer testimony on September 17, 2021 and UCA filed revised answer testimony on October 13, 2021. Among other things, the answer testimony included proposed disallowances to the amount of EGC that Atmos Energy should be allowed to recover and recommendations regarding future actions to mitigate exposure to price increases during similar weather events in the future, including the use of conservation messaging.

5. On October 1, 2021, Atmos Energy filed a Motion for Summary Judgment regarding the disallowance proposed by Staff.

6. Prior to the October 15, 2021, deadline for rebuttal testimony and the deadline for responding to the Motion for Summary Judgment, the parties engaged in settlement discussions to attempt to resolve the disputed issues regarding Atmos Energy's application. Those discussions were productive and the parties reached an agreement in principle to resolve this proceeding. On October 14, 2021, Atmos Energy filed an unopposed motion to modify the procedural schedule to provide the parties additional time to memorialize their agreement in writing and prepare supporting testimony for the Commission's consideration.

Specifically, the Company asked the Commission to extend the deadline for rebuttal testimony and the deadline for responding to the Motion for Summary Judgment. The unopposed motion was granted by Decision No. R21-0647-I on October 18, 2021.

Settlement Terms and Conditions

The Settling Parties agree that the Commission should approve Atmos Energy's application for recovery of the EGC, subject to the following modifications and conditions:

7. Staff, the UCA, and CEO will no longer support or pursue the proposed disallowances regarding the EGC.

8. Upon filing of this Stipulation, Atmos Energy will withdraw its Motion for Summary Judgment.

9. Consistent with the recommendations of one or more of Staff, the UCA, and CEO, a new Extraordinary Gas Cost Recovery Rider ("EGCRR") will be established to recover the EGC, subject to the following:

- a. The EGC will be recovered through separate volumetric EGCRR rates for each of the Company's rate divisions, to be implemented by an advice letter filed simultaneously with a proposed tariff change to remove the unprotected amounts of Excess Deferred Income Tax ("EDIT") liabilities from the rate rider currently returning both protected and unprotected EDIT to customers as discussed below in section 9(c).
- b. Other rate elements that are assessed on volumes or gas costs generally will not be impacted by the EGCRR.
- c. The \$23,549,609 in EGC will be offset by the regulatory liabilities associated with the differences between actual FAS 87 pension

expense and FAS 87 pension expense in base rates tracked in accordance with Decision No. C18-0311 in Proceeding No. 17AL-0429G (Atmos Energy's last general rate case) from April 13, 2018 (the effective date of new rates from that last rate case) through September 30, 2021,¹ and unprotected Excess Deferred Income Tax projected liabilities as of February 1, 2022 (the expected day the rider from this proceeding will take effect), totaling \$10,157,808, to be applied pro-ratably to each rate division based on the amount of EGC incurred. The resulting net gas costs to recover from customers is \$13,391,800. The total EGC, regulatory liabilities, and net gas costs to recover for each of the Company's rate divisions are provided in Attachment 1 to this Stipulation.

- d. The EGCRRT will be set to collect the net gas costs to recover over a 24-month period for the North rate division and a 12-month period for the Southeast and Southwest rate divisions. It is estimated that the proposed rates will collect, on average, the following amounts per customer:

¹ Going forward, Atmos Energy will continue to track the difference between actual FAS 87 pension expense and FAS 87 pension expense recovered in base rates as required by Decision No. C18-0311 in Proceeding No. 17AL-0429G.

	North Division (24 months)	Southeast Division (12 months)	Southwest Division (12 months)
Monthly Rate (\$ Per ccf)	\$0.06809 per ccf	\$0.09633 per ccf	\$0.0317 per ccf
Est. Monthly per residential customer	\$3.58	\$5.48	\$1.83
Est. Monthly per commercial customer	\$21.84	\$21.61	\$9.81

The proposed EGCRR tariff and rates are provided in Attachment 2 to this Stipulation.

- e. The EGCRR will commence on the first day of the month of the first month no less than 45 days from the effective date of the Commission decision approving the Stipulation.
- f. No carrying cost or interest will be applied to the EGC.
- g. Any over- or under-collection of the net gas costs to recover through the EGCRR will be put into Account 191 and flowed through the normal operation of the Gas Cost Adjustment (“GCA”) mechanism in the annual GCA filing following the end of the applicable EGCRR effective period for each rate division.
- h. Low-income Energy Assistance Program (“LEAP”), Percentage of Income Payment Programs (“PIPP”) recipients, and irrigation customers will be exempted from the EGCRR.
- i. Atmos Energy will run bill inserts for all residential customers providing notice of the EGCRR and PIPP eligibility during the billing cycle for the month prior to the rider taking effect and send e-mails

with the same information to residential customers for whom the Company has email addresses.

10. Atmos Energy will schedule a meeting with Settling Parties to discuss near-term and long-term conservation messaging (“Conservation Messaging Meeting”) within 30 days of this Stipulation being executed by all Settling Parties.

11. On an interim basis during the 2021-2022 heating season, Atmos Energy will implement conservation messaging to customers in its Colorado gas distribution areas where the forecasted usage exceeds 75% of the Design Day Heating Degree Days (“HDD”),² subject to the following conditions:

- a. The contents of such interim conservation messaging will be discussed during the Conservation Messaging Meeting described above in section 10.
- b. The interim conservation messaging will be delivered to customers via text message to the extent permitted by law, email, social media posts, and the Atmos Energy website prominently displayed on the Colorado page. The interim conservation messaging will also be distributed to media outlets such as print, television, and radio outlets in a manner to be proposed by Atmos Energy and developed in the Conservation Messaging Meeting described above in section 10.
- c. The interim conservation messaging will be delivered to customers as soon as practicable but no later than 12 hours after the Company becomes aware that the forecasts exceed the trigger established above

² The Design Day is a twenty-four hour period of demand that is used as a basis for planning gas volume requirements.

in section 11. Messaging will continue thereafter no less than daily until the forecast trigger is no longer met.

- d. Atmos Energy will continue to record the difference between the forecasted gas demand and actual gas demand on a daily basis for each GCA rate division during the 2021-2022 heating season. Atmos Energy will also track the days when conservation messaging is delivered during the 2021-2022 heating season. Atmos Energy will provide these data in the proceeding discussed below in section 11(e).
- e. The Company will include conservation messaging during the 2022-2023 heating season and beyond as a topic in either its next DSM filing or a stand-alone filing made on or before April 29, 2022. Parties will discuss the appropriate forum to address this issue in the stakeholder meeting discussed above in section 10. Parties may address those topics as they deem appropriate in that future filing. Atmos Energy will continue conservation messaging, as described in section 11, until a final decision in its next DSM Plan is effective; or upon subsequent mutual agreement of the parties to this Stipulation; or until ordered to do otherwise by the Commission.
- f. This Stipulation does not limit the messaging Atmos Energy may elect to provide to its customers for conservation, reliability, or other purposes.

12. Atmos Energy will conduct a stakeholder meeting before the Company's next general rate case filing and no later than April 29, 2022 to discuss interruptible services

(“Interruptible Meeting”). Atmos Energy will report on the outcome of the Interruptible Meeting and will address those issues as it deems appropriate in its next general rate case filing in Colorado. All other Settling Parties will be free to make such recommendations as they deem appropriate regarding those issues in that rate case.

The Public Interest

13. The Settling Parties agree that this Stipulation is in the public interest and will be supported by the Settling Parties’ testimony in this proceeding. Atmos Energy will prefile settlement testimony. Unless otherwise ordered, the other Settling Parties will be available to answer questions from the Commission at the hearing if a hearing is held. The Settling Parties agree to support the Stipulation as being in the public interest in proceedings before the Commission and to advocate in good faith that the Commission approve the Stipulation in its entirety.

14. Specifically, the Settling Parties agree that the Stipulation is in the public interest because it provides for an efficient and comprehensive resolution of the issues raised in this proceeding, including (a) reducing the amount of extraordinary gas costs to be recovered from customers, (b) spreading the recovery of the net extraordinary gas costs over a reasonable period of time to mitigate rate impacts, (c) excluding any carrying costs, (d) providing for conservation messaging during the 2021-2022 heating season, and (e) establishing a path for other issues to be resolved in future proceedings.

General Terms and Conditions

15. The Settling Parties agree that this Stipulation represents a compromise of their positions and has been negotiated as a comprehensive settlement. As such, the Settling Parties acknowledge that their support and advocacy for the Stipulation is based upon the Stipulation as a whole and not based upon its individual components viewed in isolation.

16. The Settling Parties agree that all negotiations relating to this Stipulation are subject to CRE 408, and that no party will be bound by any position asserted in the negotiations, except to the extent expressly stated in this Stipulation.

17. The Settling Parties agree that except as otherwise expressly noted in this Stipulation: (a) the execution of this Stipulation will not be deemed to constitute an acknowledgment of any Settling Party of the validity or invalidity of any particular method, theory or principle of ratemaking or regulation, and no Settling Party will be deemed to have agreed that any principle, method or theory of regulation employed in arriving at this Stipulation is appropriate for resolving any issue in any other proceeding; (b) the execution of the Stipulation will not constitute the basis of estoppel or waiver in future proceedings by any Settling Party; and (c) no Settling Party will be deemed to be bound by any position asserted by any other Settling Party.

18. The Settling Parties acknowledge that their support and advocacy of the Stipulation may be compromised by material alterations thereto. If the Commission rejects or materially alters the Stipulation, the Settling Parties agree that within seven days of such Commission decision any Settling Party may provide notice to the other Settling Parties of its objection to the Stipulation as modified. Upon such objection, the Settling Parties will no longer be bound by its terms and will not be deemed to have waived any of their respective procedural or due process rights under Colorado law. If a Settling Party objects to the Stipulation as modified, it may withdraw from the Stipulation.

19. If the Commission adopts and approves the Stipulation, this Stipulation resolves all disputed matters relative to this proceeding between the Settling Parties. Any

disputed matters will be deemed resolved to the extent that the Stipulation is not compromised by material alterations.

20. Except as otherwise expressly provided in this Stipulation, the issuance of a decision approving this Stipulation will not be deemed to work as an estoppel upon the Settling Parties or the Commission, or otherwise establish, or create any limitation on or precedent of the Commission, in future proceedings.

21. This Stipulation will not become effective and will be given no force and effect until the issuance of a final written Commission decision that accepts and approves this Stipulation.

22. This Stipulation may be executed in one or more counterparts and each counterpart will have the same force and effect as an original document and as if all the Settling Parties had signed the same document. Any signature page of this Stipulation may be detached from any counterpart of this Stipulation without impairing the legal effect of any signatures thereon and may be attached to another counterpart of the Stipulation identical in form hereto but having attached to it one or more signature page(s). The Settling Parties agree that “pdf” signature pages exchanged by e-mail and electronic signatures will satisfy the requirements for execution.

[Signature Page Follows]

Dated this 21st day of October 2021.

Atmos Energy Corporation

By: /s/ Kathleen R. Ocanas
Kathleen R. Ocanas
Vice President, Rates & Regulatory Affairs
Atmos Energy Corporation
Colorado-Kansas Division
25090 W. 110th Terrace
Olathe, KS 66061
Telephone: (214) 206-2823
Email: kathleen.ocanas@atmosenergy.com

Agreed on behalf of:
**Trial Staff of the Colorado Public Utilities
Commission**

By: /s/ Nardos Ghebregziabher
Nardos Ghebregziabher, Senior Economist
Economics & Financial Analysis Section
Colorado Public Utilities Commission
1560 Broadway, Suite 250
Denver, Colorado 80202
Email: nardos.ghebregziabher@state.co.us

Holland & Hart LLP

By: /s/ Thorvald A. Nelson
Thorvald A. Nelson, #24715
Nikolas S. Stoffel, #44815
Holland & Hart LLP
555 Seventeenth Street, Suite 3200
Denver, CO 80202
Main Telephone: (303) 295-8000
Direct Telephone: (303) 290-1601 and
x1626 respectively
tnelson@hollandhart.com
nsstoffel@hollandhart.com

Attorneys for
Atmos Energy Corporation

Approved as to form:
PHILIP J. WEISER
Attorney General

By: /s/ D. Ross Smith
Bryan D. Kreykes, #50608*
Lauren E. S. Caliendo, 50144*
D. Ross Smith, 54217*
Assistant Attorneys General
Revenue and Utilities Section

Attorneys for Trial Staff of the Public
Utilities Commission

1300 Broadway, 8th Floor
Denver, Colorado 80203
Telephone: (720) 508-6762 (Kreykes)
Telephone: (720) 508-6753 (Caliendo)
Telephone: (720) 508-6370 (Smith)
Fax: (720) 508-6038
Email: bryan.kreykes@coag.gov
Email: lauren.caliendo@coag.gov
Email: ross.smith@coag.gov

*Counsel of Record

Agreed on behalf of:
**Colorado Office of Utility Consumer
Advocate**

By: /s/ Cindy Schonhaut
Cindy Schonhaut
Director
Colorado Office of the Utility Consumer
Advocate
1560 Broadway, Suite 200
Denver, CO 80202
Telephone: (303) 894-2121
Email: cindy.schonhaut@state.co.us

Approved as to form:
PHILIP J. WEISER
Attorney General

By: /s/ Thomas Dixon
Thomas F. Dixon
First Assistant Attorney General
Gregory E. Bunker
Senior Assistant Attorney General
Samuel D. Eisenberg
Assistant Attorney General
Office of the Consumer Counsel Unit
1300 Broadway, 7th Floor
Denver, CO 80203
Telephone: (720) 508-6212
Telephone: (720) 508-6214
Telephone: (720) 508-6229
Email: gregory.bunker@coag.gov
Email: thomas.dixon@coag.gov
Email: samuel.eisenberg@coag.gov

Attorneys for the UCA

Agreed on behalf of:
Colorado Energy Office

PHILIP J. WEISER
Attorney General

By: /s/ David Banas
DAVID BANAS 36664*
Senior Assistant Attorney General
Natural Resources and Environment Section
1300 Broadway, 7th Floor
Denver, CO 80203
Telephone: (720) 508-6284
Email: david.banas@coag.gov

*Attorney of Record

Colorado Weather Event Development of Extraordinary Gas Cost Recovery Rider ("EGCRR") Rate

Line #	Description	2-Years Div 33 North	1-Year Div 35 Southeast	1-Year Div 36 Southwest	Total
		(a)	(b)	(c)	(d)
1	Extra-ordinary Gas Costs	\$ 19,347,269	\$ 3,120,070	\$ 1,082,270	\$ 23,549,609
2	Less Offsets	(8,345,185)	(1,345,800)	(466,823)	(10,157,808)
3	Net Gas cost to Recover	\$ 11,002,084	\$ 1,774,270	\$ 615,447	\$ 13,391,800
4	Forecasted Res/Com Sales Gas Quantity Over Recovery Period (Mcf) *	16,157,974	1,841,935	1,941,292	
5	Rate in \$ per Mcf	\$ 0.6809	\$ 0.9633	\$ 0.3170	
6	Rate in \$ per ccf	\$ 0.06809	\$ 0.09633	\$ 0.03170	
7					
8	Annual Forecasted Sales Gas Quantity (Mcf) -Residential	4,853,518	1,331,786	1,137,251	
9	Annual Forecasted Sales Gas Quantity (Mcf) -Commercial	3,225,469	510,149	804,041	
10					
11	Allocated Dollars - Residential	3,304,809	1,282,909	360,509	
12	Allocated Dollars - Commercial	2,196,254	491,427	254,881	
13					
14	Average Customer Count - Residential	76,952	19,514	16,409	
15	Average Customer Count - Commercial	8,381	1,895	2,165	
16					
17	Annual Per Residential Customer	43	66	22	
18	Annual Per Commercial Customer	262	259	118	
19					
20	Monthly Per Residential Customer	\$ 3.58	\$ 5.48	\$ 1.83	
21	Monthly Per Commercial Customer	\$ 21.84	\$ 21.61	\$ 9.81	
22					
23	Net Gas cost to Recover	\$ 11,002,084	\$ 1,774,270	\$ 615,447	
24	Total Customer Count	85,336	21,418	18,574	
25	Average per customer	129	83	33	

*Forecasted Sales and Customer Count from October 2021 GCA Filing

Atmos Energy Corporation
Gas Supply Workpaper

Carrying Cost/Daily Purchases Wp

										ATO Option 1		ATO Option 2		Paragraph 32 first bullet	Paragraph 32 second bullet	Paragraph 32 third bullet
Division 33		Sat., Feb. 13th	Sun., Feb. 14th	Mon., Feb. 15th	Tue., Feb. 16th	Wed., Feb. 17th	Thu., Feb. 18th	Fri., Feb. 19th								
Daily Purchases	Volume	25,100	30,100	29,100	25,800	10,800	15,100	7,600								
	Total Cost	\$ 4,018,116	\$ 4,590,066	\$ 4,475,676	\$ 4,075,311	\$ 1,273,505	\$ 873,757	\$ 40,838	\$ 19,347,269	\$ 7,624,146	\$ 9,673,634	\$ 4,337,098	\$ 2,981,879			
	Ave. Price	\$ 160.08	\$ 152.49	\$ 153.80	\$ 159.19	\$ 120.14	\$ 57.86	\$ 5.37								
Division 35		Sat., Feb. 13th	Sun., Feb. 14th	Mon., Feb. 15th	Tue., Feb. 16th	Wed., Feb. 17th	Thu., Feb. 18th	Fri., Feb. 19th								
Daily Purchases	Volume	4,000	4,000	4,000	4,000	4,000	2,000	-								
	Total Cost	\$ 691,980	\$ 691,980	\$ 691,980	\$ 691,980	\$ 313,000	\$ 39,150	\$ -	\$ 3,120,070	\$ 1,229,521	\$ 1,560,035	\$ 699,430	\$ 480,878			
	Ave. Price	\$ 173.00	\$ 173.00	\$ 173.00	\$ 173.00	\$ 78.25	\$ 19.58	\$ -								
Division 36		Sat., Feb. 13th	Sun., Feb. 14th	Mon., Feb. 15th	Tue., Feb. 16th	Wed., Feb. 17th	Thu., Feb. 18th	Fri., Feb. 19th								
Daily Purchases	Volume	2,000	2,000	2,000	2,000	2,000	2,000	-								
	Total Cost	\$ 193,250	\$ 193,250	\$ 193,250	\$ 193,250	\$ 272,150	\$ 37,120	\$ -	\$ 1,082,270	\$ 426,487	\$ 541,135	\$ 242,615	\$ 166,804			
	Ave. Price	\$ 96.63	\$ 96.63	\$ 96.63	\$ 96.63	\$ 136.08	\$ 18.56	\$ -								
Total		Sat., Feb. 13th	Sun., Feb. 14th	Mon., Feb. 15th	Tue., Feb. 16th	Wed., Feb. 17th	Thu., Feb. 18th	Fri., Feb. 19th								
Daily Purchases	Total Cost	\$ 4,903,346	\$ 5,475,296	\$ 5,360,906	\$ 4,960,541	\$ 1,858,655	\$ 950,027	\$ 40,838	\$ 23,549,609	\$ 9,280,153	\$ 11,774,804	\$ 5,279,143	\$ 3,629,561			

Settlement Columns added to Direct Testimony WPs

Allocation %	Unanimous Settlement	
	Liabilities	Net
82%	\$ 8,345,185	\$ 11,002,084
13%	\$ 1,345,800	\$ 1,774,270
5%	\$ 466,823	\$ 615,447
	\$ 10,157,808	\$ 13,391,800

Excess Deferred Income Tax Liability

Unprotected	Protected	Total	
12,711,400	(7,221,912)	5,489,488	Base Rate EDITL
(3,050,338)	1,765,356	(1,284,982)	Amortization through 01/31/2022
9,661,062	(5,456,556)	4,204,506	Net Remaining 02/2022 forward

Pension Tracker Liability

496,747

Total Estimated Offset

10,157,808

CO - 21A-0186G (Feb'2021 Winter Weather) – Staff 12-01

Following up on the Company's Response to CPUC 6-2. Are there dollars associated with any of the listed regulatory liabilities that the Company agrees could be used to reduce the magnitude of the dollars needed to be recovered from ratepayers for costs related to the Extreme Weather Event? If yes, please provide the magnitude of the regulatory liability by rate area for December 31, 2021.

RESPONSE:

Yes, there are dollars associated with the regulatory liabilities information provided in response to Staff Question No. 6-02 that the Company agrees could be used to reduce the magnitude of the dollars need to be recovered from customers for the extraordinary gas costs incurred during the Extreme Weather Event.

Please see Attachment 1 which shows an estimated \$9.7 million Unprotected Excess Deferred Income Tax Liability (EDITL) as of 12/31/2021 that the Company believes could be used to off-set the magnitude of the dollars needed to recover costs related to the Extreme Weather Event. Please note that using all of the Unprotected EDITL would leave a \$5.5 million Protected EDITL Asset to be collected over the next eleven years.

In addition to the Unprotected EDITL the Company has approximately \$496,747 in Pension Tracker Liability as of 09/30/2021. FY 2022 information is not available therefore the exact liability as of 12/31/2021 is uncertain however it could grow by another \$30,000 - \$40,000 in Q1 of FY 2022.

The Company would propose to allocate these dollars based on customer count in each rate area; however it would be open to other mutually agreeable methodologies.

ATTACHMENT:

ATTACHMENT 1- Staff_12-01_Att1 - EDITL Amortization as of 12-31-2021.xlsx, 13 Pages.

Sponsors: Jared Geiger and Joe Christian **Response Date:** September 14, 2021

ATMOS ENERGY CORPORATION
1555 Blake St., Suite 400
Denver, Colorado 80202

Colo. P.U.C. No. 7 Gas
Original Sheet No. 7A

NATURAL GAS RATES

EXTRAORDINARY GAS COST RECOVERY RIDER

APPLICABILITY

As defined and approved in Commission Decision No. _____, Proceeding No. 21A-0186G, the extraordinary gas costs incurred by Atmos from the Extreme Weather Event of Presidents' Day Weekend 2021 shall be recovered from customers through Atmos' Extraordinary Gas Cost Recovery Rider ("EGCRR"). The EGCRR applies to Residential and Commercial customers who are subject to the GCA, with applicable amounts and duration determined by rate division as shown in the table below. LEAP and PIPP customers and Irrigation customers are exempt from the EGCRR. The EGCRR will remain static throughout the recovery period and will end as set forth below.

<u>Description</u>	<u>N</u>	<u>SE</u>	<u>SW</u>
EGCRR (\$ per ccf)	\$0.06809	\$0.09633	\$0.03170
Recovery Period Start	February 1, 2022	February 1, 2022	February 1, 2022
Recovery Period End	January 31, 2024	January 31, 2023	January 31, 2023
Total To Recover	\$11,002,084	\$1,774,270	\$615,447

OVER/UNDER RECOVERY

Over or under recovery of the EGCRR will be determined at the conclusion of the recovery period by determining the difference between the approved Total Recovery EGCRR costs and the actual costs recovered. This over or under recovered balance shall be included in a subsequent Gas Cost Adjustment true-up filing. In accordance with the Commission's GCA rules, interest will be paid on any net over-recovered amounts.

**DO NOT WRITE
IN THIS SPACE**

Advice Letter No.
Decision or Authority No.

s/Kathleen R. Ocanas
Title: Vice-President Regulatory &
Public Affairs

Issue Date:
Effective Date:

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-02
Page 1 of 2

REQUEST:

Refer to the Direct Testimony of William D. Matthews at 13:18 - 14:3. Mr. Matthew discusses the removal of \$2.2 Billion in debt from the capital structure proposal in this proceeding. With respect to this adjustment respond to the following:

- a. Identify the amount of deferred gas costs on the books of Atmos Energy's divisions in the states of Colorado, Kansas, and Texas.
- b. Provide copies of testimony submitted by Atmos Energy in base rate case proceedings in 2021 covering the topic of return on equity and capitalization.
- c. Mr. Matthews' testimony references that the Company expects that the majority of this debt will be securitized. What is the estimated amount of debt that is expected to be securitized? Also, explain whether it would be appropriate to include the portion of debt not expected to be securitized within the Company's capital structure?
- d. Confirm that the first full sentence on page 14 refers to the Company's Tennessee operations.

RESPONSE:

- a. Please see Attachment 1. Please note that differences in the September 30, 2021 amounts identified in Attachment 1 and order/settlement amounts identified in the Company's response to CAPD 1-01 will be booked closer to the time the securitization is finalized.
- b. Please see Attachment 2 and Attachment 3 for a copy of direct testimonies submitted in the Company's 2021 Kentucky base rate case proceeding.
- c. In Texas \$2,021,888,534 will be securitized through the Texas Natural Gas Securitization Finance Corporation, a newly created entity under the Texas Public Finance Authority. This securitization will remove the entire balance from the Atmos Energy Corporation corporate structure. In Kansas, \$102,517,847, subject to finalizing actual docket costs, will be securitized by an entity to be established under Atmos Energy Corporation's consolidated legal structure. The remaining Uri-related gas cost in Colorado will not be securitized but recovered over 12 - 24 month period.

The Company believes that it would be inappropriate to include any of the \$2.2 billion in long-term debt financing in the consolidated capital structure, even to account for the Colorado extraordinary gas cost because the Company intends to refinance the entire amount with the receipt of proceeds from the Securitization financing. The difference in the March 2022 debt and Securitization Bonds, approximately \$70m - \$80m, will be funded through general corporate funds and therefore any uncollected Colorado extraordinary costs will be part of the consolidated capital structure.

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-02
Page 2 of 2

d. Confirm.

ATTACHMENTS:

CPAD_1-02_Att1 - TN ARM Request 1-2a - TX KS & CO Deferred Gas Costs.xlsx
CPAD_1-02_Att2 - 2021 KY Christian Direct Testimony, Affidavit, Exhibits FINAL.pdf
CPAD_1-02_Att3 - 2021 KY Rate Case - D'Ascendis Direct Testimony, Affidavit, Exhibit FINAL.pdf



Atmos Energy Corporation

Basic Balance Sheet

For the Month Ended September, 2021

Company

	Mid-Tex LDC SA - MTXCOM	West Texas Div - 030COM	Kansas Divisions - KANSDV	Colorado Divisions - COLODV
	Fiscal 2021 September	Fiscal 2021 September	Fiscal 2021 September	Fiscal 2021 September
Miscellaneous current and accr - 2021 Winter Event - interest 1740-14225	6,901,252	1,158,566	-	-
Miscellaneous current and accr - 2021 Winter Event - gas cost 1740-14224	1,721,048,119	282,610,587	-	-
Other Regulatory Assets - 2021 Winter Event - gas cost 1823-14224	-	-	88,196,622	-
Other Regulatory Assets - 2021 Winter Event - interest 1823-14225	-	-	812,849	-

Winter Event Regulatory Assets as of September 30, 2021 by state

Texas

Kansas

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

APPLICATION OF ATMOS ENERGY	)	
	)	
CORPORATION FOR AN ADJUSTMENT	)	Case No. 2021-00214
	)	
OF RATES AND TARIFF MODIFICATIONS	)	

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 – Composite Allocation Factors

Exhibit JTC-2 – Base Period to Test Period O&M

Exhibit JTC-3 – Deprecation Regulatory Reserve Credit Rates

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 nineteen 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

1 Business Administration from East Texas State University. I am a Certified Public
2 Accountant in the State of Texas and a member of the American Institute of
3 Certified Public Accountants. I have made presentations before industry groups
4 and the NARUC Staff Subcommittee on Accounting and Finance.

5 My professional experience includes approximately two years of public
6 accounting experience with a large local accounting firm based in Dallas, Texas. In
7 1989, I accepted a position in the internal audit group with Atmos Energy. I was
8 promoted to positions of increasing responsibility within the Atmos Energy finance
9 team during my first nine years with the Company. I joined Atmos Energy's
10 Colorado-Kansas operations as Vice President & Controller in June of 1998 and,
11 effective December 1, 2001, was named Vice President of Rates & Regulatory
12 Affairs. I assumed my current position on August 1, 2007.

13 **Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?**

14 A. Yes. I am licensed by the State of Texas as a Certified Public Accountant ("CPA").

15 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY**
16 **PUBLIC SERVICE COMMISSION ("COMMISSION") OR OTHER**
17 **REGULATORY ENTITIES?**

1 A. Yes. I have testified in the Company's previous two rate proceedings¹ as well as
2 supported the Company's position in the Commission's Investigation of the Tax
3 Cut and Job's Act on the Rates of Investor Owned Utilities.² I have submitted
4 testimony before the Kansas Corporation Commission ("KCC") in five general rate
5 case proceedings³ and provided oral comments to the KCC in a rules investigation.⁴
6 I have also submitted testimony before the Mississippi Public Service Commission
7 to amend our tariffs to add a supplemental growth rider,⁵ to amend our formula rate
8 tariff to establish a system integrity plan and establish a rural development pilot
9 program,⁶ and to request a system integrity rider and support our capital budget for
10 2015 through 2024.⁷ I have also submitted testimony before the Louisiana Public
11 Service Commission to amend our formula rate making tariffs to reduce lag related
12 to system integrity investment as well as reaffirm our existing formula rate making
13 tariffs.⁸ Finally, I filed testimony before the Colorado Public Utilities Commission
14 numerous times, including the Company's prior general rate case proceedings;⁹ gas
15 prudence reviews;¹⁰ a Phase II class cost of service/rate design proceeding;¹¹ a

¹ 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 Case No. 2017-00481.

³Docket 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.

⁸ Docket No. U-32987 (2014) and Docket No. U-35535 (2020).

⁹Proceeding Nos. 00S-668G, 09AL-507G, 13AL-0496G, 14AL-0300G, 15AL-0299G, 17AL-0429G.

¹⁰ Proceeding Nos. 00P-296G and 03P-229G.

¹¹ Proceeding No. 02S-411G.

1 transportation terms & conditions proceeding;¹² an upstream gas transportation
2 matter;¹³ a complaint proceeding regarding upstream gas transportation;¹⁴ an
3 Advanced Metering Infrastructure surcharge matter;¹⁵ a proposal to extend the pilot
4 related to recovering uncollectible gas costs through the Gas Cost Adjustment
5 (“GCA”) mechanism;¹⁶ the Company’s proposal to put into effect a System Safety
6 and Integrity Plan;¹⁷ and the Company’s application for a Certificate of Public
7 Convenience and Necessity to implement the Greeley Building Project.¹⁸

8 **I. PURPOSE OF TESTIMONY**

9 **Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?**

10 A. I am responsible for supporting the calculation of the Company’s revenue
11 requirements in this case including the Company’s proposed rate base, operating
12 expenses, capital structure and embedded cost of debt to be utilized in establishing
13 base rates for the future test period of calendar 2022. I am sponsoring the following
14 Filing Requirements (FR):

15 FR 16(6)(a) Forecasted financial data presented as pro forma adjustments
16 to the base period;

17 FR 16(6)(b) Forecasted adjustments limited to twelve (12) months
18 immediately following the suspension period;

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.

1 FR 16(6)(c) Capitalization and net investment rate base;

2 FR 16(6)(f) Reconciliation of the rate base and capitalization;

3 FR 16(7)(b) The utility's most recent capital construction budget

4 containing at a minimum a three (3) year forecast of

5 construction expenditures;

6 FR 16(7)(c) Description of all factors used in preparation of the forecast

7 test period - income statement, operation and maintenance

8 expenses, employee and labor expenses, capital construction

9 budget;

10 FR 16(7)(d) Annual and monthly budget for the 12 month period

11 preceding filing date, the base period and the forecast period;

12 FR 16(7)(f) Detailed information for each major construction project

13 constituting more than five percent (5%) of the annual

14 construction budget within the three (3) year forecast;

15 FR 16(7)(g) Detailed information for the aggregate of construction

16 projects constituting less than five percent (5%) of the

17 annual construction budget within the three (3) year forecast;

18 FR 16(7)(h) (1) Operating Income Statement; (2) Balance Sheet; (3)

19 Statement of Cash Flows; (4) Revenue Requirements; (9)

1 Employee Level; (10) Labor cost changes; (11) Capital
2 Structure Requirements; and (12) Rate Base;
3 FR 16(7)(i) Most Recent FERC or FCC Audit Reports;
4 FR 16(7)(n) Latest 12 months of the monthly managerial reports
5 providing financial results of operations in comparison to
6 forecast;
7 FR 16(7)(o) Complete monthly budget variance reports, with narrative
8 explanations, for the twelve (12) months immediately prior
9 to the base period, each month of the base period, and any
10 subsequent months, as they become available;
11 FR 16(7)(t) List all commercial or in-house computer software,
12 programs, and models used to develop schedules and work
13 papers associated with this application;
14 FR 16(8)(a) A jurisdictional financial summary for both the base period
15 and the forecasted period that details how the utility derived
16 the amount of the requested revenue increase;
17 FR 16(8)(b) A jurisdictional rate base summary for both the base period
18 and the forecasted period with supporting schedules, which
19 include detailed analyses of each component of the rate base;

18 A. The base period is October 1, 2020 through September 30, 2021 (“Base Period”)
19 and the forecasted test period is January 1, 2022 through December 31, 2022 (“Test
20 Period”)

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

3 A. Yes, I am sponsoring Exhibits JTC-1 through JTC-4, which are attached to my
4 testimony. Exhibit JTC-1 provides the composite factors used to allocate common
5 costs for the purpose of the Test Period in this rate proceeding. Exhibit JTC-2 is a
6 Base Period to Test Period O&M comparison by cost element. Exhibit JTC-3 are
7 my proposed Depreciation Regulatory Reserve Credit rates. Exhibit JTC-4 is the
8 Lead Lag Study utilized in the Company's revenue requirement.

9 **Q. DO YOU ADOPT THESE FILING REQUIREMENTS AND EXHIBITS,**
10 **AND THEIR ASSOCIATED SCHEDULES, AND MAKE THEM PART OF**
11 **YOUR TESTIMONY?**

12 A. Yes, I adopt the filing requirements, exhibits, and their associated schedules, and
13 make them a part of my testimony.

14 **Q. WHAT IS THE SOURCE OF THE DATA USED TO COMPLETE THE**
15 **FILING REQUIREMENTS THAT YOU ARE SPONSORING?**

16 A. The source of the data includes the accounting books and records of the Company
17 which are being sponsored by Company witness Ms. Michelle Faulk along with
18 information provided by the following witnesses to this proceeding: Mr. Josh
19 Densman (revenues, gas cost and margin forecast; sales statistics); Mr. Dane
20 Watson (depreciation rates); and Mr. Dylan D'Ascendis (rate of return on equity).

14 Q. WHAT IS THE AMOUNT OF ATMOS ENERGY'S REVENUE
15 DEFICIENCY?

16 A. The amount of revenue deficiency Atmos Energy seeks to recover in its proposed
17 rates is \$16,389,804 as shown on line 11 of Schedule A. This deficiency is based
18 on the forecasted Test Period twelve months ended December 31, 2022, an average

²⁰ Final Order of Case No. 2017-00349, Pages 16-17 of the final order stated, “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.” Final Order of Case No. 2018-00281, Page 29 of the final order stated, “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”.

1 rate base of \$596,130,007 and a required rate of return on rate base of 7.66%. The
2 amount is reduced by the annual amortization of the Company's excess deferred
3 income tax liability ("EDITL") of \$5,406,740 which has been updated to reflect
4 new information regarding the Company's Unprotected EDITL items and discussed
5 in in Section IX of my testimony. The amount also reduced by a return of the
6 Depreciation Regulatory Liability of \$9,862,441 and discussed in Section VIII of
7 my testimony

8 **Q. WHAT IS THE SOURCE OF FORECASTED TEST PERIOD ADJUSTED**
9 **OPERATING INCOME OF \$29,418,392 SHOWN ON SCHEDULE A, LINE**
10 **2?**

11 A. The forecasted Test Period adjusted operating income is determined in Schedule C
12 using inputs discussed in my testimony and the testimony of Company witnesses
13 Josh Densman and Dane Watson.

14 **III. RATE BASE**

15 **Q. HOW DID YOU DETERMINE THE LEVEL OF RATE BASE FOR THE**
16 **TEST PERIOD?**

17 A. The Test Period rate base of \$ \$596,130,007, is summarized in Schedule B-1 and
18 detailed in Schedules B-2 through B-6. Each component of the Test Period rate
19 base is a thirteen-month average forecasted amount, unless noted otherwise. The
20 components of rate base are:²¹ net plant in service, construction work in progress,

²¹ To comply with final order of Case No. 2018-00281, page 26, construction work in progress and associated ADIT items are not included in rate base.

1 cash working capital, regulatory assets and liabilities, and an allowance for other
2 working capital items consisting of materials and supplies and gas stored
3 underground, less customer advances for construction and deferred income taxes.

4 **Q. HOW WAS THE TEST PERIOD GROSS PLANT IN SERVICE**
5 **PROJECTED?**

6 A. I began with actual per books gross plant as of March 31, 2021 including allocations
7 of shared plant as discussed by Ms. Faulk in her testimony²². I used the capital
8 spending projection for April - September 2021, the fiscal year 2022/2023 budget
9 for the months in fiscal year 2022 (October 2021 through September 2022) and
10 fiscal year 2023 (October 2022 through December 2022). The direct 2022/2023
11 budget is prepared at a project level and the shared services and division office are
12 forecast at the same level as the base period. Projected plant retirements were based
13 on the level of retirements recorded in the six months of actuals included in the
14 Base Period (October 2020 through March 2021). Routine retirements in each
15 forecasted month were projected to continue at the same level in the same month
16 in future years.

17 **Q. WHAT IS THE FORECASTED TEST PERIOD CAPITAL PROJECTION?**

18 A. The forecasted Test Period capital investment projection is \$56.39 million which is
19 comprised of three components - the direct capital spending for Kentucky for the

²² Please see Exhibit JTC-1 Allocation Factors

1 forecasted test period, the amount allocated to Kentucky resulting from capital
2 spending by the Kentucky/Mid-States Division's general office and the amount
3 allocated to Kentucky resulting from capital spending by the SSU during the
4 forecasted test period.

5 **Q. WHAT KEY PRIORITIES ARE ADDRESSED THROUGH THE**
6 **KENTUCKY DIRECT CAPITAL BUDGET?**

7 A. Investments that focus on customer safety and system reliability are our highest
8 priorities for capital budgeting. The next priority is public improvements and state
9 and local public works projects such as highway relocations. The next priority is
10 customer growth. Atmos Energy continues to build good working relationships
11 with developers, economic development boards, and growing communities to meet
12 the needs of the customer and to accommodate customer growth on its system.
13 Next in order of priority, a modern fleet of vehicles and equipment (backhoes,
14 safety equipment, ditchers, first responder equipment, air compressors, welding
15 machines, etc.) allows us to maintain our system and continue to provide a reliable
16 and efficient level of service to our customers. To enhance the level of customer
17 service provided in the field, we also continue to make investments in new
18 technology. Technology is a strategic investment that will enable us to continue
19 improving our business processes, hold down operating costs, and meet the
20 changing expectations of our customers.

1 **Q. WHAT IS KENTUCKY’S FY2021, FY2022, AND FY2023 DIRECT**
2 **CAPITAL BUDGET?**

3 A. The direct budget for Kentucky for FY 2021 is \$58.3 million, for FY 2022 is \$63.2
4 million and for FY 2023 is \$67.0 million.

5 **Q. HOW DID YOU ADJUST KENTUCKY’S DIRECT CAPITAL BUDGETS IN**
6 **ORDER TO PREPARE THE FORECASTED TEST PERIOD CAPITAL**
7 **BUDGET?**

8 A. For the months of the base period I used actual plant additions through March 2021
9 and the divisions latest reforecast of capital spending for FY2021, including PRP,
10 for April 2021 – September 2021. For forecasted period from October 2022 –
11 December 2022 and the Test Period (January 2022 – December 2022) I used the
12 capital budget for FY 2022 and FY 2023, excluding PRP investment for the final
13 quarter of the test period. I would note that since we are providing additional
14 project level detail rather than applying a factor to the current year capital budget
15 that the growth budget is anticipated to increase between FY 2022 and FY 2023.

16 **Q. IS THE PIPE REPLACEMENT PROGRAM (“PRP”) ESTABLISHED IN**
17 **DOCKET NO. 2009-00354 COMPLETE?**

18 A. No, it is not complete. While the Company’s effort to replace bare steel pipe is not
19 complete, it remains on track. Please see the testimony of Mr. Brannon Taylor and
20 Mr. Ryan Austin for further discussion.

1 **Q. IS THE PRP INCLUDED IN THE KENTUCKY DIRECT CAPITAL**
2 **BUDGET?**

3 A. Yes.

4 **Q. DID YOU INCLUDE CUMULATIVE PRP INVESTMENT IN THE TEST**
5 **YEAR RATE BASE AND REVENUE REQUIREMENT?**

6 A. Yes, as required by the PRP tariff, the impact of the Company's PRP investment is
7 included throughout the filing and reflected in the total revenue requirement of
8 \$179,994,286 proposed by the Company.

9 **Q. HOW DO YOU PROPOSE TO HANDLE THE AUGUST 2021 AND AUGUST**
10 **2022 PRP FILINGS TO AVOID OVER-RECOVERY OF FISCAL YEAR 2022**
11 **AND FISCAL YEAR 2023 PRP INVESTMENT?**

12 A. The Company's annual August PRP filing normally includes PRP investment that
13 is forecasted to be spent between October 1 and September 30 following the August
14 filing. The forecasted Test Period rate base in this case includes actual and
15 forecasted PRP investment that the Company will make through September 30,
16 2022. The amount of PRP investment forecasted to be spent from October 1, 2021
17 to September 30, 2022 is \$27.9 million, which is built into the rate base and revenue
18 requirement of this proceeding. The PRP surcharge rates that result from our
19 August 2021 PRP case will be set to zero once the rate schedule that results from
20 this proceeding (Case No. 2021-00214) becomes effective. Because the rates
21 resulting from this proceeding are based upon the Company's cumulative cost of
22 service, including the \$28.1 million of forecasted PRP investment from October 1,
23 2021 - September 30, 2022, the Company ensures that it earns a return on this PRP

1 investment once and only once. Furthermore, by only including PRP investment
2 through September 30, 2022 (three months short of the end of the test period in this
3 proceeding) the Company can make its August 2022 PRP filing (which will include
4 PRP investment forecasted for October 1, 2022 to September 30, 2023) as
5 scheduled and not disrupt the annual timeline for PRP filings.

6 **Q. WHY HAS THE COMPANY CHOSEN TO FILE THIS CASE IN THIS**
7 **MANNER - WITH ALL CAPITAL INVESTMENT INCLUDED IN THE**
8 **FORWARD LOOKING TEST YEAR?**

9 A. The Company has chosen to file this comprehensive general rate case in the manner
10 described above in order to preserve forward looking treatment on its capital
11 investment and related operating expenses.

12 **Q. WHAT IS THE SIGNIFICANCE OF FORWARD LOOKING TREATMENT**
13 **IN RATEMAKING?**

14 A. Forward looking treatment, as generally described in the context of rate of return
15 regulation, entails forecasting cost of service components and implementing rates
16 such that the timing of the Company's revenues collected from customers aligns
17 with the timing of its cost of service. In allowing such treatment, regulators ensure
18 that the rates customers are paying reflect the utility's cost of service and the value
19 of investment provided during the same time period.

1 **Q. DOES EXISTING KENTUCKY STATUTE ALLOW FORWARD LOOKING**
2 **TREATMENT?**

3 A. Yes. KRS 278.192 allows for forward looking treatment in rate proceedings for the
4 utilities regulated by the Commission. Atmos Energy's Kentucky rates have been
5 set on a forward looking basis going back many years (at least since 1999) and were
6 set on a forward looking basis in the Company's most recent rate case, Case No.
7 2018-00281. As a result, the Company has chosen to file this case by exercising its
8 option under the statute.

9 **Q. DID THE COMPANY CONSIDER THE PROVISIONS OF KRS 278.192**
10 **WHEN PROPOSING THE PRP IN 2009?**

11 A. Yes. Given that Kentucky statute allows the Commission to utilize forward looking
12 treatment, which it has applied without exception for many years to the Company's
13 Kentucky rates, the Company proposed a pipe replacement mechanism that
14 maintained forward looking treatment and made it a cornerstone of its proposal.
15 The Company viewed that proposal as consistent with the statute.

1 **Q. WHAT WOULD BE THE DISADVANTAGE OF ELIMINATING**
2 **FORWARD LOOKING TREATMENT ON THE COMPANY'S**
3 **INVESTMENT?**

4 A. Eliminating forward looking treatment would result in a regulatory construct that
5 systematically prevents the Company from having an opportunity to earn its
6 authorized return on equity ("ROE").

7 **Q. WHAT CAUSES A FILING BASED ON HISTORIC COST OF SERVICE TO**
8 **SYSTEMATICALLY PRODUCE REVENUES LOWER THAN THOSE**
9 **REQUIRED TO ALLOW A UTILITY TO EARN ITS AUTHORIZED**
10 **RETURN ON EQUITY?**

11 A. Regulatory lag. If a Company must invest capital, experience depreciation on its
12 investment, and support a given level of operating expenses in one time period but
13 wait until a future time period to recover those costs, it cannot mathematically cover
14 its total cost of service (including return) in a timely fashion. This is the definition
15 of regulatory lag and it is especially harmful when a utility is in an era of increasing
16 capital investment requirements (as is the case for virtually every public gas utility
17 in America today). Atmos Energy's test period capital investment plan for
18 Kentucky calls for investment that is three times its forecasted level of depreciation.
19 The additional depreciation expense alone forecasted in this case for the forward
20 looking test year given that level of investment is \$1.3 million. At that rate,

1 regulatory lag would systematically cause the Company to fail to earn its authorized
2 return, should rates be set on a time period that does not include forward looking
3 treatment.

4 **Q. HOW WAS THE KENTUCKY/MID-STATES GENERAL OFFICE**
5 **CAPITAL BUDGET DEVELOPED?**

6 A. The capital budget for the Kentucky/Mid-States Division general office was
7 developed in conjunction with Kentucky's capital budget as well as the capital
8 budgets for all other rate divisions within the Division as part of the Division's total
9 capital budget. The Division general office budget for the forecasted Test Period is
10 \$22,810, \$11,501 of which is allocated to Kentucky for ratemaking purposes.

11 **Q. WHAT IS THE SHARED SERVICES FORECASTED TEST PERIOD**
12 **CAPITAL INVESTMENT PROJECTION FOR THIS PROCEEDING?**

13 A. The Shared Services projection for the forecasted Test Period is \$45.57 million,
14 \$2.38 million of which is allocated to Kentucky for ratemaking purposes.

15 **Q. HOW WAS THE TEST PERIOD ACCUMULATED DEPRECIATION**
16 **PROJECTED?**

17 A. I began with actual per books accumulated depreciation as of March 2021 including
18 allocations as discussed by Ms. Faulk in her testimony²³. For the months of April
19 2021 through the end of the test year (December 2022), I added projected

²³ Please see Exhibit JTC-1 Allocation Factors

1 depreciation expenses (described later in my testimony) and deducted the same
2 retirements that were projected for gross plant.

3 **Q. DID YOU INCLUDE CONSTRUCTION WORK IN PROGRESS (“CWIP”)**
4 **IN THE RATE BASE?**

5 A. No. The Commission disagreed with inclusion of CWIP in the Final Order in Case
6 No. 2018-00281²⁴ therefore the Company has excluded \$8.1 million direct CWIP
7 as well as allocated CWIP from rate base.

8 **Q. HOW DID YOU DETERMINE THE AMOUNT OF TEST PERIOD CASH**
9 **WORKING CAPITAL ALLOWANCE TO INCLUDE IN RATE BASE?**

10 A. Recognizing the Commission’s findings and Final Order in Case No. 2017-00349
11 and 2018-00281, the Company prepared a lead-lag study to calculate its Cash
12 Working Capital requirement. The lead-lag study is discussed in Section XI of my
13 testimony.

14 **Q. HOW WAS THE TEST PERIOD AMOUNT OF MATERIAL AND**
15 **SUPPLIES DETERMINED?**

16 A. I calculated the 13 month average amount of materials and supplies in the
17 forecasted Test Period using average actual balances recorded in the six months of
18 actuals included in the Base Period (October 2020 - March 2021). The Company
19 does not anticipate a significant change in the amount of materials and supplies in

²⁴ Final Order of Case No. 2018-00281, Page 26.

1 the test year. The calculation method maintains the historic level of materials and
2 supplies while smoothing out any historic month to month fluctuations.

3 **Q. HOW WAS THE AMOUNT OF GAS IN STORAGE DETERMINED?**

4 A. The projected amount of gas in storage is discussed in Mr. Josh Densman's
5 testimony.

6 **Q. HOW DID YOU PROJECT THE AMOUNT OF TEST PERIOD**
7 **CUSTOMER ADVANCES FOR CONSTRUCTION?**

8 A. I calculated the amount of customer advances in the forecasted Test Period based
9 on the average of actual amounts booked in the base period from October 2020 to
10 March 2021. The Company does not anticipate a significant change in the amount
11 of customer advances in the test year. The calculation method maintains the historic
12 level of customer advances while smoothing out any historic month to month
13 fluctuations.

14 **Q. DID YOU PROPOSE ANY ADJUSTMENTS FOR ANY REGULATORY**
15 **ASSETS AND LIABILITIES?**

16 A. Yes. I included the 13 month average of the projected unamortized balance of two
17 regulatory assets and one regulatory liability. I have included a regulatory asset for
18 the unamortized balance of the rate case expenses deferred by the Company in Case
19 No. 2018-00281 per the Final Order. I am also proposing a regulatory asset for the
20 unamortized balance of projected rate case expenses that the Company projects to

1 incur in the context of this proceeding. The Company projects rate case expenses
2 totaling \$399,097. I am proposing a three year amortization of these costs in
3 recognition of the Commission's findings and Final Order in Case No. 2017-00349.
4 The amortization expense is included in O&M and the details concerning the
5 regulatory assets are documented on Schedule F.6 in FR 16(8)(f). I also included
6 the 13 month average of the projected unamortized balance of the excess deferred
7 income tax liability discussed in Section IX of my testimony.

8 **Q. DID YOU PROPOSE ANY RATE BASE ADJUSTMENT FOR A**
9 **DEPRECIATION REGULATORY LIABILITY RELATED TO**
10 **DEPRECIATION²⁵?**

11 A. No, I have not proposed any reduction to rate base because when discussing the
12 issue of depreciation rates to adopt in Case No. 2018-00281, the Commission
13 indicated that the regulatory liability should be established without carrying charges
14 and stated, "This gradual approach will ensure that Atmos's customers receive the
15 full benefit of the reasonable depreciation methodology, while limiting the impact
16 of the change on Atmos."²⁶ Reducing rate base would effectively be imposing a
17 carrying charge therefore rate base has not been reduced I discuss the amortization
18 aspect of the Depreciation Regulatory Liability in Section VIII of my testimony.

²⁵ Final Order of Case No. 2018-00281, Page 59, Ordering Paragraph No. 5 which 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."

²⁶ Final Order of Case No. 2018-00291, Page 18, first paragraph.

1 **Q. DOES THE COMPANY’S RATE FILING REFLECT A PROJECTION OF**
2 **ACCUMULATED DEFERRED INCOME TAX (“ADIT”)?**

3 A. Yes. ADIT balances are projected in a manner consistent with the Final Order in
4 Case No. 2018-00281. The projection excludes ADIT items consistent with the
5 Final Order in Case No. 2018-00281. In addition, CWIP and ADIT items and SEBP
6 ADIT items are excluded from rate base to align with their removal from the case.

7 **Q. DID YOU PREPARE A RECONCILIATION OF TEST PERIOD RATE**
8 **BASE AND CAPITALIZATION?**

9 A. Yes. To comply with section 16(6)(f) of 807 KAR 5:001, I prepared the
10 reconciliation in Schedule FR 16(6)(f). It shows the differences between the Test
11 Period average rate base and Test Period end capital that result from using 13-month
12 averages in rate base, certain balance sheet items not being included in rate base as
13 well as amounts included in rate base for particular categories that differ from the
14 amount included on the balance sheet.

15 **IV. O&M BUDGETING PROCESS**

16 **Q. WHAT ARE THE OBJECTIVES OF THE COMPANY’S O&M**
17 **BUDGETING PROCESS?**

18 A. The objectives of the Company’s O&M budgeting process are to: (1) formalize the
19 process of identifying the anticipated costs of operating and maintaining Atmos
20 Energy’s systems each year; (2) ensure that all policies and procedures associated
21 with the annual budgeting process are consistently adhered to by the functional

1 managers and officers; (3) assess the appropriateness of routine maintenance
2 requirements and non-capital expenditures proposed by the functional managers
3 and officers to ensure that the amounts are adequate to deliver safe, reliable and
4 efficient natural gas service to the Company's customers; and (4) ensure that the
5 O&M budget properly reflects our strategic operational and financial plans. These
6 objectives are applicable to the Company as a whole as well as to its various
7 division, state and local level operations.

8 **Q. CAN YOU DESCRIBE THE COMPANY'S O&M BUDGETING PROCESS?**

9 A. Yes. O&M costs are budgeted on a fiscal year basis, which begins on October 1 of
10 each year (consistent with the seasonal operations of our business) and runs through
11 September 30 of the following year. Preparation of operating and construction
12 budgets for a fiscal year formally begins in late May of each year and culminates
13 with completion of final budgets in late August, just prior to the beginning of the
14 fiscal year. Budget preparation is based on meeting the four objectives described
15 above. Budgets are approved at multiple levels beginning with
16 supervisors/managers up through division leadership. Additional reviews are
17 performed by corporate executive operations management and their staff. High
18 level reviews of the division budgets are also performed by the Company's senior
19 executives who are presiding members of the Company's Management Committee.
20 The Board of Directors must review and approve the total Company budget before

1 finalization and implementation. This approval typically occurs in September of
2 each year.

3 **Q. WHAT ROLE DOES THE O&M BUDGETING PROCESS PLAY IN THE**
4 **COMPANY'S FINANCIAL PLANNING?**

5 A. Atmos Energy's Business Planning and Analysis Department is responsible for
6 financial planning at the enterprise level. That department receives direction from
7 the Board of Directors concerning forward-looking financial objectives for the
8 Company. Business Planning and Analysis is responsible, with significant input
9 and collaboration from division leadership, for translating those enterprise targets
10 into a financial plan for each division and rate jurisdiction. It is the collaboration
11 between Business Planning and Analysis and division leadership that ensures that
12 all four of the objectives described above are met each year. Spending targets are
13 established as a result of this collaboration.

14 **Q. SO FAR YOU HAVE DESCRIBED THE O&M BUDGETING PROCESS.**
15 **CAN YOU EXPLAIN HOW THE BUDGET IS PREPARED WITHIN THE**
16 **PARAMETERS OF THIS PROCESS?**

17 A. Yes. The O&M budget is prepared by type of cost element, such as labor, benefits,
18 transportation, rents, office supplies, etc. Within each cost element we budget
19 expenses at the sub-account level. The prior year's actual costs, year-to-date actual
20 costs and budgeted costs for the remainder of the fiscal year are used as guidelines

1 for budgeting by functional managers and officers. The budgets are prepared using
2 a web-based software tool called PlanIt. This tool allows cost center owners to
3 enter their budgets and for management to review budgets using a number of
4 standard and ad hoc reports.

5 **Q. ARE THESE BUDGETS PREPARED BY FERC ACCOUNT?**

6 A. No. In our experience, FERC accounts do not provide a sufficient level of detail to
7 enable us to understand the costs within each account. For budgeting purposes (and
8 subsequent managing of expenses), we need more individualized expense types that
9 relate to the operation of each cost center. FERC accounts do not provide that level
10 of detail. However, we do identify our expenditures by FERC account as well as
11 expense type. This provides a timely analysis of the type of charges being expensed
12 by FERC account.

13 **Q. HOW DOES ATMOS ENERGY CONVERT ITS O&M BUDGET BY COST**
14 **ELEMENT INTO FERC ACCOUNTS?**

15 A. To convert our budget and forecast to FERC accounts, prior year actual
16 expenditures are downloaded from the general ledger by FERC account and cost
17 element. A calculation is then made to determine within each cost element type the
18 percentage of spending attributable to each FERC account. Each percentage factor
19 was then applied to the fiscal year 2021 budget and test period forecast by cost type
20 to develop a budget and Test Period forecast by FERC account.

1 **V. CONTROL AND MONITORING PROCESSES**

2 **Q. DOES THE COMPANY EMPLOY ANY METHODOLOGY TO MONITOR**
3 **AND CONTROL O&M ACCORDING TO BUDGETED LEVELS?**

4 A. Yes. Atmos Energy utilizes variance monitoring to ensure financial quality control
5 of O&M expenses by formalizing the analysis of variances by cost type and cost
6 center. On a quarterly basis, the Company's Management Committee hosts a
7 meeting with Company Utility Operations, SSU department heads, select Board of
8 Directors members and external auditors at a formal Quarterly Performance
9 Review. Financial and operating results are reviewed for the latest quarter and year-
10 to-date. The goal is to keep all levels of management informed of O&M spending
11 in comparison to budgeted amounts, in order to allow management to react to
12 unanticipated events on a timely basis.

13 **Q. ARE O&M VARIANCES EVALUATED MORE FREQUENTLY THAN ON**
14 **A QUARTERLY BASIS?**

15 A. Yes. The Kentucky Mid-States Division Finance Department conducts a thorough
16 review of O&M actual to budget variances each month.

17 **Q. PLEASE DESCRIBE THE MONTHLY VARIANCE REVIEW PROCESS.**

18 A. The process begins by examining, at the Division level, significant variances by
19 cost type (labor, benefits, materials, rents, etc.). Significant variances are
20 researched until an explanation is found. Reasonable explanations could include
21 events that affected the entire Division or a particular cost center or region. In some

1 cases, clarifying information is sought from cost center owners to explain unusual
2 variances or transactions. For some cost types, clarifying analysis is provided by
3 SSU departments. If errors are found, they are most often corrected in the current
4 month's business. Occasionally, however, errors are discovered after the books are
5 closed, and, depending on materiality, they are corrected in the following month's
6 business.

7 **Q. DOES ANYONE ELSE WITHIN THE DIVISION HAVE THE ABILITY TO**
8 **MONITOR OR REVIEW O&M VARIANCES?**

9 A. In addition to the research conducted by the Division Finance Department, each
10 cost center owner has the ability to run variance reports throughout the monthly
11 closing process. Because cost center owners are held accountable for significant
12 variances to budget, they conduct their own research and often contact the Division
13 Finance Department when they find errors or have questions about the expenses
14 that were charged to their cost centers.

15 **Q. WHAT CONTROLS AND REPORTING ARE INVOLVED IN THE**
16 **MONTHLY CLOSE PROCESS REGARDING O&M VARIANCES?**

17 A. Once the monthly books are closed, the SSU Financial Reporting department in
18 Dallas publishes (electronically) the monthly Atmos Energy Financial Package.
19 This package details the financial performance for Atmos Energy at the corporate
20 and division level. For each division, the report includes a comparative income

1 statement, operating statistics (volumes, total spending), and other financial details.

2 At the end of each quarter, narrative comments are provided by Division officers to
3 describe quarterly and YTD variances. Once complete, this Financial Package is
4 available to all Atmos Energy officers and Board members for review and is an
5 official Sarbanes-Oxley control document of the Company. On a quarterly basis,
6 once the package is complete, an online questionnaire generated by our Sarbanes-
7 Oxley Compliance Tool is completed certifying that the Division Finance
8 Department has conducted a thorough review of the Division's financial
9 performance and the Financial Package and all matters addressed therein. The
10 Company's external auditors look for this certification as evidence of Sarbanes-
11 Oxley compliance.

12 After meeting the Financial Package control requirement, the Division
13 Finance Department publishes (electronically) detailed O&M reports that include
14 monthly and YTD variances for each cost center and these reports are then made
15 available to each cost center owner and their respective managers (managers,
16 Division Vice Presidents, and the Division President). This activity ensures that
17 each cost center owner receives the same information in the same format each
18 month in a timely fashion in order to make operational decisions and manage our
19 operations effectively and efficiently.

1 **Q. HAS THE O&M VARIANCE MONITORING AND CONTROL PROCESS**
2 **YOU HAVE DESCRIBED ENABLED KENTUCKY TO OPERATE**
3 **REASONABLY WITHIN ITS BUDGET EACH YEAR?**

4 A. Yes. While the table below indicates some overage in 2018 and 2019, overall, the
5 Company's actual O&M expenditures over the past eight years in Kentucky have
6 tracked closely to overall budgeted amounts or shows that conscious mid-year
7 decisions were made to vary from budget rather than reduce important ongoing
8 O&M.

Fiscal Year	Actual \$	Budget \$	Over/(Under) \$	Variance %
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%

9
10 **Q. DO YOU HAVE AN OPINION REGARDING THE SIGNIFICANCE OF**
11 **THE HISTORICAL DATA REFLECTED IN THE TABLE ABOVE?**

12 A. Yes. I examined what drove the variances in 2018 and 2019 and am satisfied that
13 in conjunction with overall corporate results, O&M objectives continued to be met.
14 Said another way, the Division communicated unplanned O&M needs and senior
15 management concurred to adjust planned O&M spending rather than make cuts to
16 meet that year's direct O&M budget. As can be seen in the FY 2020 result, despite

1 COVID and the uncertainty regarding the pandemic the O&M budget was within
2 1%.

3 **Q. WHY IS THAT IMPORTANT?**

4 A. This data demonstrates that the Company's budgeting and control processes I have
5 described form a reasonable basis for purposes of the Company's forecasted Test
6 Period O&M budget in this rate proceeding.

7 **Q. WHAT ARE THE GOALS OF THE COMPANY'S PROCESS OF**
8 **CONTROLLING AND MONITORING CAPITAL EXPENDITURE**
9 **VARIANCES?**

10 A. Variances from budgeted amounts are inherent in the process of making capital
11 expenditures. Our variance monitoring process exists to institute financial quality
12 control by formalizing the analysis of variances by budget category and
13 responsibility center in a process that identifies year-to-date spending variances.
14 The goal is to keep all levels of management informed of spending by category and
15 responsibility center relative to budgeted levels and to ensure that corrective action
16 is initiated on a timely basis. This supports decision-making related to the cost and
17 appropriate management of current and future capital projects.

1 **Q. PLEASE DESCRIBE THE COMPANY’S PROCESS FOR CONTROLLING**
2 **AND MONITORING CAPITAL EXPENDITURE VARIANCES.**

3 A. The Company’s process for controlling and monitoring capital expenditure
4 variances is utilized by each operating division as well as by Shared Services. At
5 the division level the Company’s capital budgeting system maintains projects in
6 two broad categories - Blanket Functionals and Specific Projects. The Blanket
7 Functionals include total capital authorizations of a similar type such as new
8 services, leak repair, short main replacements, small integrity/reliability projects,
9 etc. Specific projects are uniquely identified such as a specific highway relocation
10 project, replacement of work equipment, or some larger significant
11 integrity/reliability project.

12 Once a project has been entered in the capital budget system a request for
13 authorization is submitted. If during the course of a project, field management
14 identifies that the costs of the project will exceed approved amounts, a request for
15 supplemental funding may be submitted. All expenditures above authorized
16 appropriation, as well as expenditures for unbudgeted projects or variances on
17 budgeted and approved projects, must be approved at the appropriate levels within
18 the Company.

19 In FY2015 the Company began utilizing a monthly capital forecast module
20 through its accounting system PowerPlan. The forecast module is updated

1 throughout the month by Project Specialists, Operation Supervisors and Operation
2 Managers as known and measurable changes occur. At the end of each month, the
3 forecast for that specific month is updated with actuals and closed to future charges
4 as part of the monthly closing process. Once current month actuals have posted,
5 the Project Specialists, Operations Supervisors and Operations Managers are given
6 two to three days to make final updates to their respective projects. Once complete,
7 the forecasts are reviewed by the Operations Supervisors, Operations Managers and
8 the VP Operations. A final review of the forecast is performed by the division
9 Finance Department. The VP of Finance communicates to the corporate Plant
10 Accounting Department that the forecast is approved. A snapshot of the forecast is
11 then taken by Plant Accounting for archiving. Upon completion of the snapshot the
12 forecast module is reopened for changes as they become known and measurable
13 during the course of the new month.

14 **VI. FORECASTED TEST PERIOD O&M BUDGET**

15 **Q. WHAT IS THE FORECASTED TEST PERIOD USED IN THIS RATE**
16 **APPLICATION?**

17 A. The forecasted Test Period is January 1, 2022 through December 31, 2022.

18 **Q. HOW WAS THE FORECASTED TEST PERIOD BUDGET DEVELOPED?**

19 A. The basis for the forecasted Test Period is the first six months of our base period
20 (October 2020 – March 2021) and last six months of our FY2021 budget.
21 Consistent with our normal annual budgeting timelines, this budget was prepared
22 during the summer of 2020 and approved by the Board of Directors in September

1 of 2020. This budget was prepared in the manner I described earlier. The forecasted
2 Test Period includes the last nine months of FY2022 and the first three months of
3 FY2023. I will describe the methodology used for the projection period in detail
4 below. The base period and FY2021 O&M budget and forecasted Test Period
5 projection were converted into FERC account detail using the method described
6 above.

7 **Q. WHAT ARE THE COMPONENTS OF O&M FOR THE FORECASTED**
8 **TEST PERIOD?**

9 A. The forecasted Test Period O&M is comprised of three parts: expenses incurred
10 and booked directly in Kentucky (rate division 009), allocated expenses from the
11 Division General Office (rate division 091), and allocated expenses from SSU
12 (comprised of rate divisions 002 and 012). I will describe the methodology used
13 for the projection for each of the three components.

14 **Q. WHAT COMPRISES THE BASE PERIOD LEVEL OF COST FILED IN**
15 **THIS RATE APPLICATION?**

16 A. The Base Period level of cost is October 1, 2020 through September 30, 2021. It is
17 composed of six months of actual results through March 2021 and six months of
18 our FY2021 budget.

19 **Q. WHAT IS THE DIRECT O&M FOR THE BASE PERIOD?**

20 A. \$16,133,469.

1 **Q. WHAT IS THE DIRECT O&M BUDGET FOR THE FORECASTED TEST**
2 **PERIOD?**

3 A. \$15,662,747.

4 **Q. WHAT IS THE DIFFERENCE BETWEEN THE BASE PERIOD O&M AND**
5 **TEST PERIOD O&M²⁷?**

6 A. The difference is a decrease of \$470,721 and reflects adjustments I have made for
7 labor and benefits, rent, other O&M and bad debt.

8 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR LABOR AND BENEFITS.**

9 A. The labor forecast for the forecasted Test Period is based on the Company's
10 approved FY2021 budget. As part of the normal budgeting process, each
11 employee's total salary, expected capital / expense ratio and expected standby and
12 overtime amounts are included. While there is always a normal level of position
13 vacancy at any given point in time, we strive to fill open positions in a timely
14 manner when and if filling the position is justified by current workload. The Base
15 Period level of total labor expenditures represents a fully staffed level minus the
16 normal level of vacancies and employee levels are projected to remain relatively
17 constant from the base period to the test period. Base pay increases go into effect
18 each October 1 and averaged 3.0% for the increases that are effective October 1,
19 2020. These increases are captured as part of the FY2021 budget. An adjustment

²⁷ Please see Exhibit JTC- 2 for O&M by Cost Element

1 was made as part of the forecast to account for an average wage increase of 3.0%
2 to become effective October 1, 2021. The 3.0% is consistent with the average level
3 of increases from the past several years. Overall, direct labor expense is projected
4 to increase \$200,085 from the base period to the test period.

5 Benefits are projected as a fixed benefit load percentage of labor expense
6 plus an amount for workers' comp insurance. The Test Period benefits expense of
7 \$ 1,695,038 is \$110,002 lower than the base period.

8 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO OTHER O&M.**

9 A. Other O&M consists of all expenses except labor, benefits, rent and bad debt. In
10 filings involving forward looking test periods, the Company normally includes in
11 O&M its most recent budget without adjustments for the months where the budget
12 and test year overlap and applies an inflation factor to these O&M categories for
13 months when the forward looking test period extends beyond the Company's
14 budget. However, recognizing the Commission's findings in Case No. 2013-
15 00148,²⁸ I have not inflated these O&M categories above budgeted levels in this
16 proceeding.

²⁸ 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.

1 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO BAD DEBT.**

2 A. Our goal is to keep bad debt no higher than 0.50% of residential, commercial and
3 public authority margin during any given year. But for the COVID-19 Pandemic,
4 we work vigorously to collect bad debts and reduce the impact of bad debt expense
5 on customers. To arrive at the bad debt projection of \$363,216, I calculated 0.50%
6 of residential, commercial and public authority margin from the revenue projection
7 in the direct testimony of Company witness Mr. Josh Densman. This projection is
8 \$516,579 lower than the Base Period.

9 **Q. GIVEN THE COVID-19 PANDEMIC AND THE COMMISSIONS ORDER**
10 **SUSPENDING COLLECTIONS, DO YOU BELIEVE THAT 0.50% IS A**
11 **REASONABLE LEVEL TO USE FOR ESTABLISHING RATES IN THIS**
12 **CASE?**

13 A. I believe that 0.5% is a very aggressive goal and we will likely exceed this
14 percentage as we return to normal collection activities, however I don't have any
15 quantitative basis on which to base a different level of expense with the certainty
16 that a ratemaking adjustment requires to be known and measurable.

1 **Q. IS THERE A SOLUTION THAT THE COMMISSION COULD EMPLOY**
2 **THAT WOULD BALANCE THE INTEREST OF THE CUSTOMER AND**
3 **THE COMPANY IN REGARD TO BAD DEBT EXPENSE?**

4 A. Yes. Similar to the Depreciation Regulatory Liability, I would encourage the
5 Commission to authorize the Company to establish a regulatory asset and defer
6 write-offs until the next case. The benchmark for bad debt would need to be clearly
7 identified²⁹ in the final order and would obligate the Company to defer amounts
8 above or below the benchmark and address the amortization of this regulatory asset
9 in the next base rate case. Establishment of a regulatory asset would avoid both an
10 over and under recovery of bad debt expense that is resulting from the uncertainty
11 of COVID-19.

12 **Q. WHAT IS THE AMOUNT OF THE DIVISION'S GENERAL OFFICE O&M**
13 **ALLOCATED TO KENTUCKY FOR THE BASE PERIOD?**

14 A. \$ 5,234,684.

15 **Q. WHAT IS THE AMOUNT OF THE DIVISION'S GENERAL OFFICE O&M**
16 **BUDGET ALLOCATED TO KENTUCKY FOR THE FORECASTED TEST**
17 **PERIOD?**

18 A. \$4,737,049.

²⁹ The Company has included \$363,216 for bad debt expense and unless modified during the proceeding would become the benchmark for bad debt expense.

1 **Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE GENERAL**
2 **OFFICE BASE PERIOD AND FORECASTED TEST PERIOD AMOUNTS.**

3 A. The difference is a decrease of \$148,118 and reflects adjustments I have made for
4 labor and benefits, and other O&M. The budgeting process and forecast
5 methodologies are identical for both direct O&M and General Office O&M.
6 Therefore, the categories of adjustments made to forecast General Office O&M are
7 also the same as direct.

8 **Q. WHAT IS THE AMOUNT OF SHARED SERVICES O&M ALLOCATED TO**
9 **KENTUCKY FOR THE BASE PERIOD?**

10 A. \$9,943,507.

11 **Q. WHAT IS THE AMOUNT OF THE SHARED SERVICES O&M BUDGET**
12 **ALLOCATED TO KENTUCKY FOR THE FORECASTED TEST PERIOD?**

13 A. \$8,647,639.

14 **Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE SHARED**
15 **SERVICES BASE PERIOD AND FORECASTED TEST PERIOD**
16 **AMOUNTS.**

17 A. The difference is a decrease of \$1,295,868. The SSU budget is prepared in a fashion
18 consistent with that of the Division. Once the SSU department heads complete,
19 submit and get approval for their budgets, the appropriate level of expenses are

1 allocated to the Kentucky rate jurisdiction per the methodologies described in Ms.
2 Michelle Faulk's testimony.

3 **Q. WHO MONITORS SHARED SERVICES BILLINGS TO THE DIVISION?**

4 A. Shared Services expense billings are reviewed as part of our monthly close process
5 described earlier. The Division Finance Department is then responsible for
6 communications with Financial Reporting in Dallas for explanations of any
7 significant variances.

8 **Q. WHAT IS THE TOTAL FORECASTED TEST PERIOD O&M THAT**
9 **RESULTS FROM THE SUM OF THE DIRECT, GENERAL OFFICE AND**
10 **SSU COMPONENTS?**

11 A. \$29,047,435.

12 **Q. DO THE FORECASTED O&M AMOUNTS DISCUSSED IN YOUR**
13 **TESTIMONY INCLUDE THE RATEMAKING ADJUSTMENTS**
14 **QUANTIFIED ON SCHEDULE C-2?**

15 A. Yes. Schedule C-2 contains seven ratemaking adjustments.

- 16 • Adjustment for Sales and Promotional Advertising Expenses

17 The first adjustment removes \$172,549 of sales and promotional advertising
18 from test year sales expense. It is quantified on Schedule F.4.

- 19 • Adjustment for Regulatory Asset Amortization Expenses

1 The second adjustment adds \$161,141 to test year administrative and general
2 expense to account for the three year amortization of the expected costs
3 pertaining to this case and Case No. 2018-00281. The amounts are quantified
4 on Schedule F.6.

5 • Adjustment for Expense Report Exclusion

6 The third adjustment removes \$52,895 of certain expense report items from test
7 year administrative and general expense. The Company's goal is to ensure that
8 its Kentucky rates rest upon a sound foundation of unquestionable costs. The
9 Company is committed to achieving that goal even if it means foregoing
10 recovery of a certain amount of legitimate business expense in an effort to
11 ensure that there can be no question about what remains. The expense report
12 exclusion adjustment is made to exclude certain cost items of which the
13 Company does not intend to seek recovery from its customers in this case. The
14 excluded amounts are quantified on Schedule F.8 and occur in Kentucky as well
15 as the Division General Office and SSU.

16 • Adjustment for Incentive Compensation

17 The fourth adjustment removes the performance portion of incentive
18 compensation expenses associated with all of its employees. This adjustment
19 is \$1,443,557. The Company believes incentive compensation is a critical part
20 of the ability to attract and retain employees at competitive market rates, and

1 should be included as a recoverable O&M expense. Atmos Energy is not unique
2 in making incentive compensation part of the overall compensation package
3 that it provides to its employees. The Company designs its total compensation
4 package to be in the middle of the job market in which we compete for talent.
5 This means that there are as many companies offering total compensation above
6 Atmos Energy's package as there are below it for comparable jobs. It is
7 important to understand that "total compensation" does not represent only base
8 salary, but also includes bonuses, benefits, retirement, etc. Because Atmos
9 Energy falls in the middle of the job market in terms of the overall compensation
10 packages, the Company believes the incentive compensation costs that are a
11 component of this overall compensation package are reasonable and should be
12 recovered as part of revenue requirement. In order to meet the Company's
13 incentive pay criteria, Company employees must work together to ensure that
14 the Company operates efficiently and effectively. Efficient and effective
15 operations translate into lower costs and therefore into lower rates for
16 customers. Strong financial performance for the Company and lower rates for
17 customers are, therefore, not mutually exclusive. However, in recognition of
18 the Commission's findings in Case No. 2013-00148³⁰, I have removed this

³⁰ See *id.* at 19-20.

1 expense in this proceeding for the sole purpose of simplifying the regulatory
2 review process. This adjustment is quantified on Schedule F.10.

3 • Adjustment for Certain Retirement Plan Expenses

4 The fifth adjustment removes costs associated with the 401(k) match for
5 employees that also participate in the Company's pension plan. This adjustment
6 is \$378,830. While the Company supports the prudence of these costs as part
7 of its comprehensive rewards program for employees, I have removed these
8 costs in the same manner in which they were removed from revenue
9 requirement in Case No. 2018-00281 consistent with the Commission's
10 findings and Final Order³¹ for the sole purpose of simplifying the regulatory
11 review process in the current rate case proceeding. This adjustment is
12 quantified on Schedule F.11.

13 • Adjustment for Directors' Stock Expenses

14 The sixth adjustment removes costs associated with stock awarded to members
15 of the Board of Directors as part of their compensation. This adjustment is
16 \$138,339. While the Company supports the prudence of these costs as part of
17 its market competitive compensation package for Directors, I have removed
18 these costs in the same manner in which they were removed from revenue
19 requirement in Case No. 2018-00281 consistent with the Commission's

³¹ Case No. 2018-00281, Final Order Page 27.

findings and Final Order³² 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 \$88,305 in costs associated with SERP 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

Q. ARE THERE ANY EXPENSES FOR LOBBYING RELATED ACTIVITIES INCLUDED IN THIS FILING?³³

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. Company witness Brannon Taylor discusses in his direct testimony how Kentucky division employees address any

³² Case No. 2018-00281, Final Order, Page 27.

³³ Case No. 2018-00281, Final Order, Page 54

1 potential indirect connection to those activities to take additional precautions
2 against the inclusion of any lobbying related activities in rates.

3 **Q. DO YOU BELIEVE THAT THE FORECASTED TEST PERIOD O&M**
4 **BUDGET YOU HAVE PRESENTED IS THE MOST REASONABLE**
5 **ESTIMATE OF COSTS FOR THE TEST PERIOD USED IN THIS**
6 **PROCEEDING?**

7 A. Yes. It is the best estimate we have of the Kentucky jurisdiction's future operating
8 and maintenance expenses.

9 **VII. DEPRECIATION EXPENSE AND TAXES OTHER THAN**
10 **INCOME TAXES**

11 **DEPRECIATION**

12 **Q. WHAT IS THE DEPRECIATION EXPENSE FOR THE BASE PERIOD?**

13 A. The amount of depreciation expense for the Base Period is \$19,295,729.

14 **Q. WHAT IS THE DEPRECIATION EXPENSE FOR THE FORECASTED**
15 **TEST PERIOD?**

16 A. The amount of depreciation expense for the forecasted Test Period is \$20,604,447.

17 **Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE BASE PERIOD**
18 **AND FORECASTED TEST PERIOD DEPRECIATION AMOUNTS.**

19 A. Proposed depreciation rates for the forecasted Test Period are discussed in the
20 testimony of and supported by Company witness Mr. Dane Watson. The
21 depreciation rates are applied to the applicable categories of plant for the Kentucky

1 jurisdiction as well as the General Office and Shared Services division, resulting in
2 total depreciation expense. The amounts allocated from the General Office and
3 SSU to Kentucky are based upon the cost allocation methodology more fully
4 described in Ms. Michelle Faulk's testimony³⁴.

5 **Q. YOU MENTIONED THE DEPRECIATION REGULATORY LIABILITY IN**
6 **A PREVIOUS QUESTION AND ANSWER, WHAT IS THE**
7 **DEPRECIATION REGULATORY LIABILITY?**

8 A. The Final Order in Case No. 2018-00281, Page 59, Ordering Paragraph No. 5 states,
9 "Atmos shall establish a regulatory liability in the amount of \$3,676,784 for the
10 remainder of the reduction in depreciation expense, the amortization of which will
11 be addressed in Atmos's next base rate case." The Company understands that the
12 \$3,676,784 is an annual amount and therefore divided by 12 and has been recording
13 a regulatory liability entry on a monthly basis for \$306,399 beginning in May of
14 2019. Schedule F-12 accumulates the liability beginning at the beginning of the
15 Base Period and continuing it through the end of the Test Period. As a result a total
16 of \$ \$9,804,757 will have accumulated over 32 months. WP F-12 presents the same
17 information but assumes that two more months of amortization accrues before rates
18 are implemented

³⁴ Please see Exhibit JTC-1 Allocation Factors

1 **Q. HOW DOES THE COMPANY PROPOSE TO RETURN THIS TO THE**
2 **CUSTOMER?**

3 A. The Company proposes to return the full amount over a 12 month period beginning
4 with the implementation of rates in this case. The rates will be derived by allocating
5 the full \$9,804,757³⁵ among the tariff classes and then developing the rates
6 proportionality between a fixed customer charge and a volumetric rate. Please see
7 Exhibit JTC-3 for proposed Depreciation Reserve Rates that would be implemented
8 if approved by the Commission.

9 **TAXES OTHER THAN INCOME TAXES**

10 **Q. WHAT IS THE EXPENSE LEVEL FOR TAXES, OTHER THAN INCOME**
11 **TAXES FOR THE BASE PERIOD?**

12 A. \$9,749,303.

13 **Q. WHAT IS THE LEVEL OF TAXES, OTHER THAN INCOME TAXES FOR**
14 **THE FORECASTED TEST PERIOD?**

15 A. \$10,276,153.

³⁵ Please note that the \$9,804,757 will need to be adjusted if rates are not implemented January 1, 2022 to account for any months prior to or beyond January 2022.

1 **Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE BASE PERIOD**
2 **AND FORECASTED TEST PERIOD.**

3 A. The difference is an increase of \$526,849. The components are itemized by type
4 of tax on Schedule C.2.3 F. For all months of the forecasted Test Period (January
5 1, 2022 - December 31, 2022), payroll taxes have been escalated from the FY2020
6 budget to account for base pay increases consistent with my labor forecast. The
7 monthly accrual for the Public Service Commission Assessment is based on the
8 assessment rate and projected Test Period revenues. The DOT transmission user
9 tax has been held constant from the Base Period. The Company's methodology for
10 forecasting ad valorem expense is consistent with the previous case. I developed
11 the ad valorem forecast using the methodology most recently used and approved in
12 the Company's PRP filings. That methodology develops an historical ratio of ad
13 valorem expense to plant and applies the ratio to projected levels of plant for the
14 Forecasted Test Period. The amount of taxes allocated from the Division General
15 Office and SSU is based on the allocation methodologies discussed in the Cost
16 Allocation Manual.

17 **VIII. INCOME TAXES**

18 **Q. HOW DO INCOME TAXES IMPACT BASE RATES TO CUSTOMERS?**

19 A. There are currently two main types of rate impacts (1) ongoing statutory income
20 tax expense and (2) a return of the liability for federal excess deferred income taxes.

1 **Q. WHAT ARE THE STATUTORY INCOME TAX RATES UTILIZED BY**
2 **THE COMPANY IN THIS CASE?**

3 A. The Company's rates current and proposed rates reflect a 21% federal statutory rate
4 and a 5% Kentucky state income tax rate. Because state taxes are deductible from
5 federal income tax purposes, the blended income tax rate is 24.95%.

6 **Q. HOW IS TAX EXPENSE CALCULATED IN THE CURRENT FILING?**

7 A. Tax expense is calculated by applying statutory tax rates to the forecasted return to
8 arrive at required operating income, as shown on Schedule C.1.

9 **Q. IS THIS CALCULATION CONSISTENT WITH THAT IN THE**
10 **COMPANY'S PREVIOUS RATE CASE FILINGS?**

11 A. Yes. I would note that the Company excludes the impact of the \$5.4 million
12 amortization of EDITL in calculating the current income taxes but then provides
13 the benefit to customers on Schedule A.1. The Company's method for flowing
14 through the benefit of EDITL to customers in this manner was affirmed by the
15 Commission's Final Rehearing Order for Case No. 2017-00349 issued on
16 September 17, 2018.

17 **Q. WHY IS CALCULATING THE CURRENT INCOME TAX, EXCLUSIVE**
18 **OF EDITL AMORTIZATION NECESSARY?**

19 A. If the reduction in present rates for amortization of EDITL was taken into account
20 when calculating the proposed increase, income tax expense calculated on Schedule

1 C.1, would be artificially lowered for the tax benefit related to the amortization of
2 the EDITL. This tax benefit has already been accounted for when the EDITL was
3 established on the Company's books.

4 **Q. HOW HAS THE TAX EFFECT OF THE AMORTIZATION OF THE EDITL**
5 **BEEN REFLECTED ON THE COMPANY'S BOOKS AND IN THIS**
6 **FILING?**

7 A. Upon enactment of the TCJA, in accordance with Generally Accepted Accounting
8 Principles ("GAAP"), the Company recorded on its books and records the
9 regulatory liability for excess deferred income taxes, grossed up for taxes, as well
10 as a deferred tax asset for the tax gross up. Since the flow back of EDITL to
11 customers represents a return of tax expense collected in rates that is in excess of
12 what the Company now expects to pay the federal government, this flow back
13 should not result in additional tax expense or benefit for the customers or the
14 Company. GAAP requirements state that the EDITL must be grossed up for income
15 taxes at the enacted income tax rates to reflect the revenue requirements to be
16 received from or refunded to customers in the future. This grossed up liability is
17 reflected on WP B.5F1 of the model and is the amount the Company has proposed
18 to amortize. The corresponding deferred tax asset for the tax gross up is included
19 in ADIT on Schedule B.5F

1 **Q. WHY WOULD IT BE INAPPROPRIATE TO INCLUDE THE**
2 **AMORTIZATION OF EDITL CURRENTLY IN RATES IN THE**
3 **CALCULATION OF THE PROPOSED INCREASE?**

4 A. To do so would duplicate the impact to the revenue requirement of taxes related to
5 the amortization. As I have described, the accounting requirements that the
6 Company complied with and reflected in this filing properly accounted for all
7 impacts to the revenue requirement.

8 **Q. IS THE COMPANY PROPOSING A FURTHER ADJUSTMENT TO THE**
9 **AMOUNT OF EDITL IN THIS PROCEEDING OR TO THE**
10 **AMORTIZATION PERIOD?**

11 A. Yes. Since the rate case in Case No. 2018-00281 concluded, the Company has
12 completed and filed its tax return related to the 2018 fiscal year and a detail analysis
13 of the appropriate amortization of protected EDITL to ensure no violation of
14 Internal Revenue Service (“IRS”) normalization rules. This resulted in a final
15 adjustment of the EDITL from \$35,130,387 to \$35,780,760 and a protected
16 amortization period moving from 24 to 22 years. Accordingly, the Company
17 proposes to update the EDITL in this case as shown on WP B.5.F1.

1 **Q. ARE THERE ANY OTHER CHANGES RELATED TO THE EDITL THAT**
2 **THE COMPANY PROPOSING IN THIS CASE?**

3 A. Yes. In August 2020 the IRS issued Revenue Procedure 2020-39 (“Rev Proc 2020-
4 39”). This revenue procedure state in part, “The appropriate amortization or other
5 ratemaking treatment of timing differences unrelated to accelerated depreciation,
6 such as unprotected plant or non-plant items, are to be determined by the regulator
7 in a rate proceeding, consistent with the regulatory authority over the ratemaking
8 treatment of all other elements of jurisdictional cost of service.”³⁶”

9 **Q. HOW DOES REV PROC 2020-39 IMPACT THE COMPANY’S**
10 **EVALUATION OF PROTECTED VS UNPROTECTED EDITL?**

11 A. After reviewing Rev Proc 2020-39 the Company has determined that it can treat all
12 non-property EDITL as unprotected and amortize it back to the customer over a
13 shorter period of time. The Company would propose that the return be over a five
14 year period beginning with the implementation of rates in this case and has included
15 the accelerated EDIT amortization in development of base rates. The division
16 between protected and unprotected along with the amortization is shown on WP
17 B.5.F1.

³⁶ Revenue Procedure 2020-39, Section 3. SCOPE .02 Issues beyond the scope of this revenue procedure.

1 **IX. CAPITAL STRUCTURE AND COST OF DEBT**

2 **Q. HOW IS ATMOS ENERGY ORGANIZED?**

3 A. Atmos Energy conducts its utility operations in eight states through unincorporated
4 operating divisions.

5 **Q. DO THE COMPANY'S UNINCORPORATED DIVISIONS ISSUE THEIR**
6 **OWN DEBT OR EQUITY?**

7 A. No. These divisions, including the Kentucky/Mid-States Division, are not separate
8 legal entities. Instead, these unincorporated divisions collectively comprise the
9 legal entity that is Atmos Energy Corporation. Therefore, all debt or equity funding
10 of the operations performed by the utility divisions must be (and is) issued by
11 Atmos Energy Corporation as a whole, on a consolidated basis.

12 **Q. SHOULD ATMOS ENERGY'S CONSOLIDATED CAPITAL STRUCTURE**
13 **BE USED AS THE BASIS FOR A CAPITAL STRUCTURE IN THIS**
14 **PROCEEDING?**

15 A. Yes. Although this proceeding only affects the rates which may be charged by the
16 Company for its regulated utility operations in Kentucky, the appropriate capital
17 structure for each of the Atmos Energy utility operating divisions, including its
18 Kentucky/Mid-States Division, is equivalent to the consolidated capital structure
19 for Atmos Energy as a whole. Atmos Energy's consolidated capital structure is
20 appropriate for use in setting rates for the Company's Kentucky customers because

1 Atmos Energy provides the debt and equity capital that supports the assets serving
2 those customers.

3 **Q. HOW HAS THE COMPANY RELIED ON THE CONSOLIDATED**
4 **CAPITAL STRUCTURE OF ATMOS ENERGY IN THIS PROCEEDING?**

5 A. The capital structure that is appropriate for the Company's Kentucky operations in
6 this proceeding is set forth in FR 16(8)(j). As shown on FR 16(8)(j), the capital
7 structure is the Company's thirteen month period end actual capital structure as
8 March 31, 2021, with an adjustment to the outstanding long-term debt which I
9 describe below. The thirteen month actual capital structure, as adjusted, for the
10 period ended March 31, 2021 is representative of the capital structure that will be
11 in effect during the forecast period. As shown in that FR, column (G), short term
12 debt comprises 0.02%, long-term debt comprises 42.80% and equity is 57.00% of
13 the Company's 13-month average rate base for the forward looking test period.

14 **Q. WHAT RATE DO YOU PROPOSE FOR THE EMBEDDED COST OF**
15 **LONG-TERM DEBT CAPITAL IN SETTING RATES IN THIS CASE?**

16 A. As shown in the calculation on Schedule J-3 F, column (e), a 4.00% weighted
17 average cost of long-term debt is supported.

1 **Q. IS THIS THE WEIGHTED AVERAGE COST OF LONG-TERM DEBT FOR**
2 **THE THIRTEEN MONTHS ENDED MARCH 31, 2021?**

3 A. No. The weighted average cost of long-term debt has been adjusted to reflect the
4 Company's anticipated refinancing of \$2.2 billion of financing issued in March of
5 2021 ("March 21 Financing"). The March 2021 Financing was issued to finance
6 unanticipated natural gas cost related to Winter Storm Uri. The majority, if not all,
7 of this financing will be repaid with a securitization of Winter Storm Uri gas costs
8 in the spring of 2022 therefore I have excluded the debt, and financing costs from
9 this case.

10 **Q. THE COMPANY HAS BEEN ACTIVE IN THE CAPITAL MARKETS**
11 **SINCE 2014, DO YOU ANTICIPATE THAT THERE WILL BE**
12 **ADDITIONAL DEBT AND EQUITY ISSUED DURING THE PENDENCY**
13 **OF THIS CASE?**

14 A. Yes, and I would be amenable to updating the capital structure and embedded cost
15 of long-term debt during rebuttal to reflect any additional financings or changes to
16 the equity balances of the Company. However, as I noted above and as shown in
17 FR 16(7)(h)(11), I don't expect this to have an appreciable impact on the
18 relationship between debt and equity, only on the embedded cost of long-term debt.

1 **Q. WHAT RATE DO YOU PROPOSE FOR THE COST OF SHORT-TERM**
2 **DEBT CAPITAL IN SETTING RATES IN THIS CASE?**

3 A. As shown in the calculation on Schedule J-2 F, column (e), a 25.17% weighted
4 average cost of short-term debt is supported. Please note that the Company has had
5 very little short-term debt outstanding during the 13 months ended March 2021
6 therefore the commitment administrative fees associated with the short-term debt
7 gets spread over very few dollars which results in a higher average rate.

8 **Q. IS THIS THE WEIGHTED AVERAGE COST OF SHORT-TERM DEBT**
9 **FOR THE DAILY OUTSTANDING TWELVE MONTH PERIOD END**
10 **MARCH 31, 2021?**

11 A. Yes.

12 **Q. HAS THE THIRTEEN MONTH MARCH 31, 2021 SHAREHOLDER**
13 **EQUITY BALANCE BEEN ADJUSTED IN TO REFLECT THE ISSUANCE**
14 **OF EQUITY DURING THE BASE OR FORECAST PERIOD?**

15 A. No. I believe that the Company's incremental external financing along with cash
16 flow reinvested in the business will result in an overall capital structure that is in
17 line with the thirteen month ended March 31, 2021 capital structure therefore no
18 adjustment is warranted at this time but as noted above can be updated through the
19 latest quarter end at the time of rebuttal.

1 **Q. DID THE COMMISSION EXPRESS CONCERNS WITH THE**
2 **COMPANY’S CAPITAL STRUCTURE IN CASE NO. 2018-00281?**

3 A. Yes. After discussing the Attorney General’s positions, the Company’s rebuttal and
4 accepting the Company’s updated position in rebuttal, the Commission stated,
5 “Atmos’s increase in common equity is concerning to the Commission, especially
6 as compared to the proxy companies, which the Attorney General contends have a
7 current equity ratio of 50.2 percent. Further, Atmos stated that the average
8 debt/equity ratio for the proxy group, as noted by Value Line for 2021-2023, is 44
9 percent debt and 56 percent equity....”³⁷.

10 **Q. HOW DO YOU RESPOND TO THIS CONCERN?**

11 A. As noted in my rebuttal in Case No. 2018-00281, the capital structure proposed and
12 supported in this case represents an actual cost, not a hypothetical or subsidiary cost
13 that is part of a larger holding company and can be leveraged at a higher level in
14 the corporate structure. I also noted that as the factors used by the credit rating
15 agencies to evaluate utilities demonstrate, relying too heavily on long-term debt
16 financing creates risk, as does a regulatory environment that is not supportive of
17 utilities’ ability to recover their actual costs and to have the opportunity to earn a
18 fair return on their investments. Moreover, the Company’s capital structure is
19 reflective of what is necessary to maintain its current credit metrics.

³⁷ Final Order Case No. 2018-00291, page 34.

1 **Q. WHY IS IT IMPORTANT FOR THE COMPANY TO CALCULATE ITS**
2 **REVENUE REQUIREMENT BASED UPON ITS ACTUAL CAPITAL**
3 **STRUCTURE?**

4 A. Safe and reliable service cannot be maintained at a reasonable cost if the Company
5 does not have the financial flexibility and strength to access the competitive capital
6 markets on reasonable terms. As the factors used by the credit rating agencies to
7 evaluate utilities demonstrate, relying too heavily on long-term debt financing
8 creates risk, as does a regulatory environment that is not supportive of utilities'
9 ability to recover their actual costs and to have the opportunity to earn a fair return
10 on their investments. Increasing the percentage of long-term debt in the Company's
11 capital structure negatively affects the key financial indicators relied upon by the
12 credit rating agencies, which puts the Company at risk of a credit rating downgrade
13 and increases in the cost of debt financing, both of which adversely affect all of
14 Atmos Energy's stakeholder groups, including its customers, its shareholders, and
15 its bondholders.

16 **Q. CAN ATMOS ENERGY MAINTAIN SAFE AND RELIABLE SERVICE AT**
17 **A REASONABLE COST OVER THE LONG-TERM IF IT DOES NOT**
18 **RECOVER ITS ACTUAL COSTS?**

19 A. In order to provide safe, reliable, and affordable service to its customers, Atmos
20 Energy must meet the needs and serve the interests of its various stakeholders,

1 including customers, shareholders, and bondholders. The interests of these
2 stakeholder groups are aligned with maintaining a healthy balance sheet, strong
3 credit ratings, and a supportive regulatory environment, so that the Company has
4 access to capital on reasonable terms in order to make necessary investments.

5 Safe and reliable service at a reasonable cost cannot be maintained if
6 utilities do not have the financial flexibility and strength to access the competitive
7 capital markets on reasonable terms. The authorization of a capital structure other
8 than the Company's actual capital structure will weaken the Company's financial
9 condition and adversely impact the Company's ability to address expenses and
10 investment, to the detriment of customers and shareholders. Safe and reliable
11 service for customers cannot be sustained over the long term if the interests of
12 shareholders and bondholders are minimized such that the public interest is not
13 optimized.

14 **Q. HAS THE COMPANY'S STRONGER EQUITY POSITION ALLOWED IT**
15 **TO SUCCESSFULLY MANAGE VARIOUS CHALLENGES THE PAST**
16 **FIVE YEARS?**

17 A. Yes. Although the TCJA reduced the federal income tax rate and created a need to
18 return deferred taxes to customers resulting in a negative impact to cash flow the
19 Company has been able to adjust its external financing needs and not experience a
20 downgrade by ratings agencies. When the COVID-19 Pandemic resulted in

1 Emergency Orders being issued across all of our service territories to not disconnect
2 we were able to raise additional debt early in the pandemic to maintain our liquidity
3 during uncertain times. When the Commission lowered our depreciation rates and
4 therefore cut our cash flow from operations, we have been able to manage through
5 the additional strain on our financial metrics. Last, I'll mention that with the
6 financial strength our balance sheet brings at its current capitalization, as part of
7 responding to Winter Storm Uri and despite being put on credit watch by both
8 ratings agencies we were able to quickly raise \$2.2 billion to fund extraordinary gas
9 cost on very short notice and increase our liquidity through a new short-term credit
10 facility.

11 **Q. WOULD SETTING THE COMPANY'S CAPITAL STRUCTURE AT**
12 **ANYTHING OTHER THAN ACTUAL BE BENEFICIAL TO THE**
13 **CUSTOMER?**

14 A. No. A regulatory environment that does not permit a utility to have a reasonable
15 opportunity to earn a fair return on its prudently incurred cost leads to poor results
16 in the long run. Supporting utilities that invest in the energy infrastructure in a
17 prudent and efficient manner should encouraged, not discouraged through short-
18 sighted regulatory decisions.

1 **Q. DOES ATMOS ENERGY’S ORGANIZATIONAL STRUCTURE SUPPORT**
2 **CALCULATING THE RATES IN KENTUCKY ON THE COMPANY’S**
3 **ACTUAL CAPITAL STRUCTURE?**

4 A. Yes, as I stated at the beginning of this section, Atmos Energy conducts utility
5 operations in eight states through unincorporated divisions, including the
6 Company’s Kentucky operations.

7 **Q. WHY IS THIS ORGANIZATIONAL STRUCTURE OF ATMOS ENERGY**
8 **(NON-HOLDING COMPANY) AN IMPORTANT DISTINCTION?**

9 A. Unlike other utilities that operate in Kentucky, the actual capital costs upon which
10 Atmos Energy’s Kentucky rates are calculated are not complicated by differing
11 levels of debt/equity ratios at the holding company level vs. the subsidiary level.

12 **Q. ARE THERE ADVANTAGES TO ATMOS ENERGY’S FINANCIAL**
13 **STRUCTURE?**

14 A. Yes. Operating all of the distribution and transmission business within Atmos
15 Energy Corporation saves administrative costs, results in a more transparent
16 business model, provides more transparency in financial reporting, and allows us
17 to focus on the operational needs of the gas distribution and transmission business
18 and how best to meet the financing needs as we progress through our investment
19 in natural gas infrastructure for growth and system replacement.

X. 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 cases³⁸ the study filed by the Company in its previous two cases (Case Nos. 2017-00349 and 2018-00281) were accepted “as filed” in the calculation of the rate base in the final order. In light of the Commission’s orders in those cases 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.

³⁸ 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.

1 **Q. DO YOU HAVE ANY PAST EXPERIENCE PERFORMING LEAD-LAG**
2 **STUDIES?**

3 A. Yes. In addition to our most recent Kentucky rate cases I have prepared several
4 lead lag studies for the Company, including studies filed in Atmos Energy’s last rate
5 cases in Tennessee, Colorado, and Virginia.

6 **Q. WHERE HAVE YOU INCLUDED THE LEAD-LAG STUDY?**

7 A. I have included the lead lag study as Exhibit JTC-3. For reference, I have continued
8 to name the various Schedules within Exhibit JTC-3 “ATO-CWCx”

9 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC1.**

10 A. This Schedule actually consists of two parts - Schedule ATO-CWC1A and ATO-
11 CWC1B. Schedule ATO-CWC1 A summarizes the results of the lead-lag analysis
12 for the test period that ends December 31, 2022. It shows the calculation of the
13 cash working capital requirement based on revenue and expense lag days and
14 projected expense amounts in the proposed revenue requirement.

15 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC1B**

16 A. Schedule ATO-CWC1B summarizes the results of the lead-lag analysis for the base
17 period ended September 30, 2021. It shows the calculation of the cash working
18 capital requirement based on revenue and expense lag days and actual expenses for
19 the base period.

1 **Q. PLEASE DESCRIBE HOW SCHEDULES ATO-CWC 1A AND 1B ARE**
2 **ARRANGED?**

3 A. Column (a) lists the type of expenses analyzed in the lead lag study including gas
4 costs, O&M labor, other O&M, taxes other than income, federal income tax, state
5 income tax, depreciation, long term and short term debt interest expense and return
6 on equity. Schedule ATO-CWC1A Column (b) contains the projected expenses for
7 the forecasted test period and Schedule ATO-CWC1B Column (b) contains the
8 expenses for the base period test year. Schedule ATO-CWC1A and ATO-CWC1B
9 Column (c) divides the expenses in Column (b) by 365 to arrive at the average daily
10 expense. Column (d) contains the revenue lag which is calculated on Schedule
11 ATO-CWC2. Column (e) contains the expense lags which are calculated on
12 Schedule ATO-CWC3 through Schedule ATO-CWC9 and their related Workpapers.
13 Column (f) calculates the net lag by subtracting the expense lag from the revenue
14 lag. Column (g) contains the calculation of the cash working capital requirement
15 which is calculated by multiplying Column (c) times Column (f). The cash working
16 capital requirement to be *deducted* from rate base for the forecasted test period is
17 \$3.1 million.

18 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC2.**

19 A. The average revenue lag is calculated on Schedule ATO-CWC2. The revenue lag
20 is the average number of days from the time service is provided by the company

1 until revenue related to that service is available to pay bills. It consists of four
2 subparts: the service lag, the billing lag, the collection lag and the bank lag.

3 **Q. WHAT IS THE SERVICE LAG?**

4 A. The service lag is the average number of days from the time service is provided
5 until the meter is read. Since service is provided daily and meters are read monthly,
6 the service lag is one-half of a month or 15.21 days.

7 **Q. WHAT IS THE BILLING LAG?**

8 A. The billing lag is the time lag from meter reading to bill issuance. The average
9 billing lag based on all bills issued in a heating season month (November) and a
10 non-heating season month (August), was 0.64 days, as compared to 1.41 days in
11 the previous case.

12 **Q. WHY HAS THE BILLING LAG SHOWN IMPROVEMENT SINCE THE**
13 **PREVIOUS CASE?**

14 A. I attribute the improvement to the increased deployment of automated meter
15 reading since the previous case. This has enabled more bills to be generated on the
16 same day of the read as compared to the previous case.

17 **Q. WHAT IS THE COLLECTION LAG?**

18 A. The collection lag is the average number of days between issuing a bill and
19 receiving payment. This was calculated by dividing the average daily accounts
20 receivable balance by the average daily revenue plus billed taxes. The total revenue

1 plus billed taxes may be found on WP 2-2. It resulted in a lag period of 17.31 days
2 and is an improvement since the previous case result of 23.20 due to lower gas costs
3 as compared to the previous study.

4 **Q. WHAT IS THE BANK LAG?**

5 A. The bank lag is the one-day lag between receiving payment through one of the
6 Company's ten pay channels and having funds available to draw at the bank.
7 Customer accounts receivable balances are credited when payment is received.

8 **Q. WHAT IS THE TOTAL AVERAGE REVENUE LAG?**

9 A. The resulting total average revenue lag is 34.16 days, as shown on the last line of
10 Schedule ATO-CWC2. This compares to 40.82 in the previous case. This overall
11 reduction is a key driver in the lower cash working capital requirement in this case
12 as compared to the previous case.

13 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC3.**

14 A. Schedule ATO-CWC3 shows the calculation of the average purchased gas cost
15 payment lag of 38.74 days from the delivery of the gas to the payment for the gas.
16 The schedule shows the service dates, the invoice date, and the payment date for all
17 gas invoices in the base period.

18 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC4.**

19 A. Schedule ATO-CWC4 shows the calculation of the average payroll lag, which is
20 the average number of days from the time service is provided until payroll related

1 to that service is paid. The payroll lag days consists of: the service lag, the payment
2 lag, and the check-clearing lag. The service lag is the average number of days from
3 the time labor is provided until the end of the pay period. The Company uses a
4 two-week pay period, so the service lag is seven days. The payment lag is the
5 average number of days between the end of the pay period and payment date. With
6 the Company's practice of paying on Friday for a pay period that ended the previous
7 Friday, the payment lag is seven days. Most employees receive their pay via direct
8 deposit, and therefore have no check-clearing lag. However, the few employees
9 that are paid by check result in an average check-clearing lag of 0.08 days. The
10 total average payroll lag is 14.08 days.

11 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC5.**

12 A. Schedule ATO-CWC5 shows the calculation of the average number of lag days for
13 other O&M expenses. The calculation is based on an analysis of payments for the
14 twelve months ended March 31, 2021. I analyzed a random sample of 380 invoices
15 out of the 6,573 total Kentucky O&M invoices to determine the lag between the
16 date services were provided to the Company and the date the Company paid the bill
17 for those services. In most cases, the service period could be determined from the
18 invoice. If no information was available regarding the date service was provided,
19 then the date of the invoice was used in most cases other than utilities, telecom and
20 rent. Please see WP 5-1 for the analysis.

1 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC6.**

2 A. Schedule ATO-CWC6 shows the calculation of the average payment lag days for
3 taxes other than income tax. As each tax has its unique payment due date, the
4 calculation of the lag is shown separately for each type of tax (payroll taxes - FICA
5 and unemployment, ad valorem taxes, taxes property and other, DOT fees, Public
6 Service Commission taxes and franchise and other pass through taxes).

7 **Q. PLEASE DISCUSS THE LAG RELATING TO PAYROLL TAXES.**

8 A. Payroll taxes consist of FICA taxes and unemployment taxes. FICA taxes are paid
9 by wire on the first banking day before each payday. Since paydays are normally
10 on Fridays, FICA lag days are equal to the payroll lag days for direct deposit
11 employees of 14 days less 1 day, for a total lag of 13 days. Unemployment taxes
12 are paid quarterly at the end of the month following each quarter. Therefore, for
13 unemployment taxes, the lag, as calculated from the mid-point of the quarter to the
14 payment date at the end of the following month plus the payroll service lag, is 83.6
15 days.

16 **Q. PLEASE DISCUSS THE LAG RELATING TO AD VALOREM TAXES.**

17 A. Kentucky Ad Valorem taxes for a calendar year are paid as billed throughout the
18 year following the year of assessment. Therefore, the Kentucky ad valorem tax lag,
19 as calculated from the mid-point of the calendar year to the payment date, is 346.39
20 days. Ad Valorem taxes allocated from Shared Services are paid by January 31 for

1 the year following the assessment. Therefore, the SSU ad valorem tax lag as
2 calculated from the mid-point of the calendar year to the payment date is 213.50
3 days.

4 **Q. PLEASE DISCUSS THE LAG RELATING TO TAXES PROPERTY AND**
5 **OTHER.**

6 A. Taxes Property and Other consist of various franchise agreements that are paid on
7 a per meter basis rather than on a revenue basis and Kentucky Highway Use Tax.
8 The expense lag on the franchise taxes are determined by the franchise with each
9 individual city and may be a prepayment or paid in arrears. The Kentucky Highway
10 Use Tax is paid at the end of the month in the month following the end of each
11 quarter. The weighted average lag of all taxes paid is a prepayment of 58.82 days.

12 **Q. PLEASE DISCUSS THE LAG RELATING TO THE DOT FEE.**

13 A. The annual DOT fee lag of 59 days is calculated from the midpoint of the fiscal
14 year to the payment date on May 28th of the following calendar year.

15 **Q. PLEASE DISCUSS THE LAG RELATING TO THE FRANCHISE AND**
16 **OTHER PASS THROUGH TAXES.**

17 A. Franchise and other pass through taxes consist of franchise taxes that are paid on a
18 revenue basis, Kentucky sales use tax and Kentucky school tax. The franchise taxes
19 are paid at the end of the month following the end of the quarter. The Kentucky

1 sales use tax and school tax are paid at the end of the month for the prior month.

2 The weighted lag for Franchise and other pass through taxes is 40.19 days.

3 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC7.**

4 A. Schedule ATO-CWC7 shows the calculation of the federal income tax lag. Income
5 taxes for the base period are paid in four quarterly payments during the year. The
6 average lag from the midpoint of the base period to the payment dates is negative
7 61.75 days. This is the lag for paying current taxes, however taxes that are deferred
8 are recorded as a rate base credit and thus have an expense lag of zero days.

9 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC8.**

10 A. Schedule ATO-CWC8 shows the calculation of the state income tax lag. State
11 income taxes for a fiscal year are paid on the same schedule as federal income taxes.
12 Therefore, the average lag from the midpoint of the tax year to the payment dates
13 is also a negative 61.75 days for paying current taxes, and zero days for deferred
14 taxes.

15 **Q. PLEASE DESCRIBE SCHEDULE ATO-CWC9.**

16 A. Schedule ATO-CWC9 shows the calculation of the long-term debt lag. Long-term
17 debt interest expense includes monthly payments, and semi-annual payments.
18 Interest is recorded on an accrual basis and paid in the period it is due. The long-
19 term debt lag, as calculated from the mid-point of the accrual period to the payment
20 date, averages 91.25 days.

1 **Q. PLEASE DESCRIBE SHORT-TERM DEBT LAG ON ATO-CWC1.**

2 A. In the base period short-term debt interest expense was for commercial paper. Most
3 commercial paper issued by the company is very short-term. Commitment fees are
4 generally paid at the end of the quarter. Other base period short-term debt costs
5 were prepaid. The weighted average short-term debt cost payment lag in the base
6 period was 19.40 days.

7 **Q. HOW DID YOU TREAT PREPAID ITEMS IN THE CALCULATION OF**
8 **CASH WORKING CAPITAL?**

9 A. Expenses that are paid by the Company before they are recorded as an expense are
10 included with a negative lag to reflect the difference between the payment of the
11 expense and the recording of the expense. With this method both the lag from the
12 payment to the recording of the expense and the subsequent revenue lag from the
13 provision of service to the receipt of cash are recognized in rate base.

14 **Q. IS DEPRECIATION EXPENSE PROPERLY INCLUDED IN THE LEAD-**
15 **LAG STUDY.**

16 A. Yes, because the payment for the asset precedes the receipt of service from the asset
17 and the recording of depreciation expense. The lag between payment for the asset
18 and the recording of depreciation expense is recognized by the including net plant
19 in service in rate base.

1 **Q. DOES INCLUSION OF PLANT IN SERVICE IN RATE BASE SUFFICE TO**
2 **PROPERLY ACCOUNT FOR THE ENTIRE LAG RELATING TO**
3 **DEPRECIATION?**

4 A. No. The inclusion in rate base of plant in service does not recognize the subsequent
5 lag from the provision of service to the receipt of cash for that service. By including
6 depreciation expense in the lead-lag study with a zero expense lag, the lead-lag
7 study properly recognizes the subsequent revenue lag on recovering cash related to
8 investment in plant assets. In other words, the investment in an asset is included in
9 rate base as net plant in service until depreciation is recorded on that asset.
10 Recording depreciation removes the asset from rate base, even though cash has not
11 been received to pay for the service provided by the asset, unless the revenue lag
12 on depreciation expense is included in cash working capital through the lead-lag
13 study.

14 **Q. DISCUSS THE TREATMENT OF RETURN ON EQUITY IN THE LEAD-**
15 **LAG STUDY.**

16 A. Similar to depreciation, operating income is earned at the provision of utility
17 service. There is again a revenue lag between the provision of service and the
18 receipt of cash for that service. By including return on equity in the lead-lag study
19 with a zero expense lag, the lead-lag study properly recognizes the subsequent
20 revenue lag on recovering cash related return.

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?

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

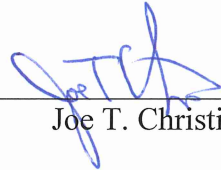
A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF)
RATE APPLICATION OF) Case No. 2021-00214
ATMOS ENERGY CORPORATION)

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. 2021-00214, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct pre-filed testimony.



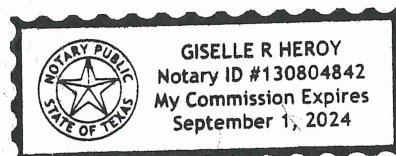
Joe T. Christian

STATE OF TEXAS
COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Joe T. Christian on this the 21st day of June, 2021.



Notary Public
My Commission Expires: 9/01/2024



Effective October 1, 2020
 ATMOS ENERGY CORPORATION
 Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/20

ALL COMPANIES

A. Composite Allocation Factor:

(a)

Gross Direct PP&E

Average Number of Customers

Total O&M Expense *

(* w/o Allocation)

Gross Direct PP&E

Average Number of Customers

Total O&M Expense

Total Composite Factor for FY 2021

	30	60	20	20	50	70	80	180
	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	Kentucky/ MidStates Div	Mississippi Div	Mid-Tex Div	Atmos P/L
Total	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
15,831,577,869	1,092,949,490	750,894,079	384,369,335	858,046,079	1,571,399,765	886,564,153	6,360,262,428	3,894,610,535
3,217,566	307,488	260,779	73,477	280,594	354,687	247,704	1,692,259	322
480,744,075	36,316,770	30,303,179	11,437,183	27,474,255	41,742,549	37,397,297	155,042,377	139,755,611
100.00%	6.71%	4.74%	2.43%	5.42%	9.93%	5.60%	40.17%	24.60%
100.00%	9.57%	8.10%	2.28%	8.72%	11.02%	7.70%	52.59%	0.01%
100.00%	7.28%	6.30%	2.38%	5.71%	8.68%	7.78%	32.25%	29.07%
100.00%	7.85%	6.38%	2.36%	6.62%	9.88%	7.03%	41.67%	17.89%

Gross Direct PP&E

Average Number of Customers

Total O&M Expense *

(* w/o Allocation)

Gross Direct PP&E

Average Number of Customers

Total O&M Expense

Total Composite Factor for FY 2021

220	232	234	303	
AELIG	UCGS-Barnsley	TLGS	TLGP	Remaining non reg
5,232,712	11,339,002	8,480,855	23,163,907	15,910,291
256	-		7	-
812,979	223,537	415,025	918,949	238,338
0.03%	0.07%	0.05%	0.15%	0.10%
0.01%	0.00%	0.00%	0.00%	0.00%
0.17%	0.05%	0.09%	0.19%	0.05%
0.07%	0.04%	0.05%	0.11%	0.05%

**Atmos Energy Corporation
 Atmos Energy Mid States Div
 Development of Allocation Factors
 Effective October 1, 2020**

Line #	Div #	Division Name	Sept ' 20 Direct Property Plant & Equipment	Percent of MidStates Property	YE Sept '20 Total O &M w/o 922	Percent of MidStates O & M	YE Sept '20 Avg Number of Customers	Percent of MidStates Customers	STAT Sub account for customers	MidStates Allocation Percent
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1										
2	09	KENTUCKY	776,387,470	49.49286	16,144,027	51.34587	178,882	50.43376	91C09	50.42417
3	93	TENNESSEE	681,920,605	43.47082	12,378,421	39.36941	152,035	42.86455	91C93	41.90160
4	96	VIRGINIA	110,377,659	7.03631	2,919,274	9.28472	23,770	6.70168	91C96	7.67424
5										
6										
7		Total	1,568,685,734.60	100.00	31,441,722.61	100.00	354,687	100.00		100.00

O&M by Cost Element

	Kentucky			SSU			Division General Office			Total		
	Base	Test	Difference	Base	Test	Difference	Base	Test	Difference	Base	Test	Difference
Labor	\$ 5,363,213	\$ 5,563,298	\$ 200,085	\$ 4,348,899	\$ 4,535,481	\$ 186,582	\$ 1,485,814	\$ 1,543,295	\$ 57,482	\$ 11,197,925	\$ 11,642,074	\$ 444,149
Benefits	1,805,039	1,695,038	(110,002)	1,424,402	1,560,446	136,044	436,276	526,913	90,637	3,665,718	3,782,397	116,680
Employee Welfare	80,887	80,887	-	1,923,950	1,832,488	(91,462)	666,055	666,055	(0)	2,670,892	2,579,430	(91,462)
Insurance	94,936	94,936	-	1,618,995	1,464,627	(154,368)	109,655	109,655	(0)	1,823,586	1,669,218	(154,368)
Rent, Maint., & Utilities	1,035,431	1,035,431	-	395,750	396,472	722	215,662	215,662	(0)	1,646,843	1,647,565	722
Vehicles & Equip	895,435	895,435	-	3,979	3,983	4	18,734	18,734	(0)	918,149	918,153	4
Materials & Supplies	790,925	790,925	-	55,224	55,141	(83)	38,834	38,834	(0)	884,984	884,900	(83)
Information Technologies	27,125	27,125	-	1,568,579	1,563,105	(5,473)	72,442	72,442	(0)	1,668,145	1,662,672	(5,473)
Telecom	188,411	188,411	-	142,295	142,835	539	173,206	173,206	(0)	503,912	504,452	539
Marketing	160,977	160,977	-	12,100	12,066	(35)	142,548	142,548	(0)	315,625	315,591	(35)
Directors & Shareholders & PR	249	249	-	324,998	323,415	(1,583)	76	76	(0)	325,323	323,740	(1,583)
Dues & Donations	103,409	103,409	-	42,447	42,190	(257)	51,142	51,142	(0)	196,997	196,740	(257)
Print & Postages	45,149	45,149	-	25,531	25,471	(60)	8,097	8,097	(0)	78,776	78,717	(60)
Travel & Entertainment	363,216	363,216	-	109,086	108,959	(127)	256,213	256,213	(0)	728,516	728,389	(127)
Training	15,437	15,437	-	47,618	47,371	(246)	37,012	37,012	(0)	100,067	99,821	(246)
Outside Services	4,107,697	4,107,697	-	1,414,531	1,411,017	(3,514)	1,489,349	1,489,349	(0)	7,011,578	7,008,064	(3,514)
Provision for Bad Debt	880,036	363,458	(516,579)	1,025,317	1,018,819	(6,499)	89,985	89,985	(0)	1,995,339	1,472,261	(523,077)
Miscellaneous	175,897	175,897	-	(4,540,195)	(4,463,016)	77,179	(56,417)	(56,417)	0	(4,420,716)	(4,343,536)	77,179
Total O&M Expenses	\$ 16,133,469	\$ 15,706,974	\$ (426,495)	\$ 9,943,507	\$ 10,080,870	\$ 137,364	\$ 5,234,684	\$ 5,382,802	\$ 148,119	\$ 31,311,660	\$ 31,170,646	\$ (141,013)
<i>RateMaking Adjustments:</i>	16,133,469	15,706,974		(9,943,507)	(10,080,870)		(5,234,684)	(5,382,802)		(31,311,659)	(31,170,646)	
Advertising Adjustments		(150,930)	(150,930)		(11,761)	(11,761)		(9,858)	(9,858)		(172,549)	(172,549)
Club Expenses		(9,878)	(9,878)								(9,878)	(9,878)
Expense Report Exclusions		(29,135)	(29,135)		(12,069)	(12,069)		(11,690)	(11,690)		(52,895)	(52,895)
SERP Expense					(67,601)	(67,601)		(20,704)	(20,704)		(88,305)	(88,305)
Regulatory Asset Amortizations		161,141	161,141			-			-		161,141	161,141
Incentive Compensation		(15,424)	(15,424)		(824,631)	(824,631)		(603,501)	(603,501)		(1,443,557)	(1,443,557)
Director's and Retirement Expenses					(517,169)	(517,169)					(517,169)	(517,169)
Grand Total	\$ 16,133,469	\$ 15,662,747	\$ (470,721)	\$ 9,943,507	\$ 8,647,639	\$ (1,295,868)	\$ 5,234,684	\$ 4,737,049	\$ (497,634)	\$ 31,311,660	\$ 29,047,435	\$ (2,264,224)

EXHIBIT JTC-3

ATMOS ENERGY CORPORATION - KENTUCKY
 DEPRECIATION LIABILITY RESERVE - REFUND RATES
 TEST YEAR ENDING DEC, 31 2022

Line No.	Billing Component	Applicable Tariffs	Current Rate	Proposed Rate	
	(a)	(b)	(c)	(d)	(e)
1	CUSTOMER CHARGES, \$/month				
2	Firm Services - Residential	G-1		(\$2.17)	
3	Firm Services - Non-Residential	G-1		(5.90)	
4	Interruptible Sales	G-2		(47.81)	
5	Firm Transportation	T-4		(48.09)	
6	Interruptible Transportation	T-3		(47.81)	
7					
8	DISTRIBUTION CHARGES, \$/Mcf				
9	Firm Sales	G-1			
10	1-300 Mcf			\$ (0.1571)	
11	301-15000 Mcf			(0.1571)	
12	Over 15000			(0.1571)	
13	Firm Transportation	T-4			
14	1-300 Mcf			\$ (0.0997)	
15	301-15000 Mcf			(0.0997)	
16	Over 15000			(0.0997)	
17	Interruptible Sales	G-2			
18	1-15000 Mcf			\$ (0.0927)	
19	Over 15000			(0.0927)	
20	Interruptible Transportation	T-3			
21	1-15000 Mcf			\$ (0.0927)	
22	Over 15000			(0.0927)	
23					

**Atmos Energy Corporation
LEAD/LAG STUDY**

<u>Company Name:</u>	Atmos Energy Corporation
<u>Jurisdiction:</u>	Kentucky
<u>Base Period:</u>	30-Sep-21
<u>Forecast Test Year:</u>	31-Dec-22
<u>Test Year for Lead/Lag Study:</u>	31-Mar-21

ATO-CWC1 A

**Atmos Energy Corporation-Kentucky
 Cash Working Capital Lead/Lag Analysis
 For Forecast Test Year Ended December 31, 2022**

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 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	77,873,656	213,352 CWC2	34.16 CWC3	38.74	(4.58)	(977,152)
3							
4	Operation and Maintenance Expense						
5	O&M, Labor	11,642,074	31,896 CWC2	34.16 CWC4	14.08	20.08	640,472
6	O&M, Non-Labor	17,514,353	47,985 CWC2	34.16 CWC5	28.06	6.10	292,709
7	Total O&M Expense	29,156,427					933,180
8							
9	Taxes Other Than Income						
10	Ad Valorem	8,660,652	23,728 CWC2	34.16 CWC6	346.39	(312.23)	(7,408,624)
11	Taxes Property and Other	19,475	53 CWC2	34.16 CWC6	58.82	(24.66)	(1,307)
12	Payroll Taxes	559,730	1,534 CWC2	34.16 CWC6	83.63	(49.47)	(75,879)
13	Franchise and other pass through	8,874,645	24,314 CWC2	34.16 CWC6	40.19	(6.03)	(146,568)
14	Public Service Commission	390,531	1,070 N/A	0.00 CWC6	0.00	0.00	0
15	DOT	145,406	398 CWC2	34.16 CWC6	59.00	(24.84)	(9,886)
16							
17	Allocated Taxes-Shared Services						
18	Ad Valorem	110,118	302 CWC2	34.16 CWC6	213.50	(179.34)	(54,161)
19	Payroll Taxes	258,445	708 CWC2	34.16 CWC6	83.63	(49.47)	(35,021)
20							
21	Allocated Taxes-Business Unit						
22	Ad Valorem	0	0 CWC2	34.16 CWC6	346.39	(312.23)	0
23	Payroll Taxes	134,837	369 CWC2	34.16 CWC6	83.63	(49.47)	(18,253)
24	Total Taxes Other Than Income	19,153,840					(7,749,699)
25							
26	Federal Income Tax	9,332,908					
27	Current Taxes	0	0 CWC2	34.16 CWC7	(61.75)	95.91	0
28	Deferred Taxes	9,332,908	25,570 CWC2	34.16 CWC7	0.00	34.16	873,471
29							
30	State Income Tax	2,358,158					
31	Current Taxes	0	0 CWC2	34.16 CWC8	(61.75)	95.91	0
32	Deferred Taxes	2,358,158	6,461 CWC2	34.16 CWC8	0.00	34.16	220,708
33							
34	Depreciation	20,604,447	56,451 CWC2	34.16	0	34.16	1,928,366
35							
36	Interest Expense - STD	298,065	817 CWC2	34.16 (1)	19.40	14.76	12,059
37							
38	Interest Expense - LTD	10,198,592	27,941 CWC2	34.16 CWC9	91.25	(57.09)	(1,595,152)
39							
40	Return on Equity	35,171,670	96,361 CWC2	34.16	0	34.16	3,291,692
41							
42	TOTAL	204,147,764					(3,062,527)
43							

(1) Please see 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 September 30, 2021

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 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	77,873,656	213,352 CWC2	34.16	CWC3 38.74	(4.58)	(977,154)
3							
4	Operation and Maintenance Expense						
5	O&M, Labor	11,197,925	30,679 CWC2	34.16	CWC4 14.08	20.08	616,039
6	O&M, Non-Labor	20,113,734	55,106 CWC2	34.16	CWC5 28.06	6.10	336,147
7	Total O&M Expense	31,311,659					952,187
8							
9	Taxes Other Than Income						
10	Ad Valorem	8,118,738	22,243 CWC2	34.16	CWC6 346.39	(312.23)	(6,944,997)
11	Taxes Property and Other	2,071	6 CWC2	34.16	CWC6 58.82	(24.66)	(140)
12	Payroll Taxes	441,245	1,209 CWC2	34.16	CWC6 83.63	(49.47)	(59,798)
13	Franchise and other pass through	8,874,645	24,314 CWC2	34.16	CWC6 40.19	(6.03)	(146,568)
14	Public Service Commission	355,417	974 N/A	0.00	CWC6 0.00	0.00	0
15	DOT	219,252	601 CWC2	34.16	CWC6 59.00	(24.84)	(14,921)
16							
17	Allocated Taxes-Shared Services						
18	Ad Valorem	52,699	144 CWC2	34.16	CWC6 213.50	(179.34)	(25,893)
19	Payroll Taxes	300,360	823 CWC2	34.16	CWC6 83.63	(49.47)	(40,705)
20							
21	Allocated Taxes-Business Unit						
22	Ad Valorem	0	0 CWC2	34.16	CWC6 346.39	(312.23)	0
23	Payroll Taxes	200,995	551 CWC2	34.16	CWC6 83.63	(49.47)	(27,239)
24	Total Taxes Other Than Income	18,565,422					(7,260,262)
25							
26	Federal Income Tax	6,177,506					
27	Current Taxes	0	0 CWC2	34.16	CWC7 (61.75)	95.91	0
28	Deferred Taxes	6,177,506	16,925 CWC2	34.16	CWC7 0.00	34.16	578,147
29							
30	State Income Tax	325,132					
31	Current Taxes	0	0 CWC2	34.16	CWC8 (61.75)	95.91	0
32	Deferred Taxes	325,132	891 CWC2	34.16	CWC8 0.00	34.16	30,429
33							
34	Depreciation	19,295,729	52,865 CWC2	34.16	0	34.16	1,805,869
35							
36	Interest Expense - STD	273,867	750 CWC2	34.16	(1) 19.40	14.76	11,075
37							
38	Interest Expense - LTD	9,366,243	25,661 CWC2	34.16	CWC9 91.25	(57.09)	(1,464,983)
39							
40	Return on Equity	33,302,197	91,239 CWC2	34.16	0	34.16	3,116,721
41							
42	TOTAL	196,491,411					(3,207,973)
43							

(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 the CWC Study Test Year Ended March 31, 2021**

Line No.	Description (a)	Weighted Average Lag (b)
1	Average Billing Lag (1) =	0.64
2		
3	Service Lag =	15.21
4		
5	Collection Lag:	17.31
6	(Test Yr Average Daily Accounts Receivable / Test Yr Average Daily Revenue)	
7		
8	Bank Lag (2) =	<u>1.00</u>
9		
10	Total Revenue Lag =	<u><u>34.16</u></u>
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 September, 2017 and January, 2018	
15	(2) Please see the relied upon labeled "CWC2 Bank Lag" for the lag by payment channel	

Atmos Energy Corporation-Kentucky
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For the CWC Study Test Year Ended March 31, 2021

CWC WP 2-1

Line No.	Date	Total
1	Wednesday, April 1, 2020	9,331,184.88
2	Thursday, April 2, 2020	9,506,129.74
3	Friday, April 3, 2020	9,639,303.85
4	Saturday, April 4, 2020	9,639,303.85
5	Sunday, April 5, 2020	9,533,324.84
6	Monday, April 6, 2020	7,852,709.56
7	Tuesday, April 7, 2020	7,596,891.15
8	Wednesday, April 8, 2020	7,344,727.31
9	Thursday, April 9, 2020	7,604,955.81
10	Friday, April 10, 2020	7,604,955.81
11	Saturday, April 11, 2020	7,604,955.81
12	Sunday, April 12, 2020	7,218,221.30
13	Monday, April 13, 2020	5,824,792.95
14	Tuesday, April 14, 2020	5,869,542.02
15	Wednesday, April 15, 2020	7,072,291.80
16	Thursday, April 16, 2020	7,464,120.80
17	Friday, April 17, 2020	7,948,256.20
18	Saturday, April 18, 2020	7,948,256.20
19	Sunday, April 19, 2020	7,446,363.72
20	Monday, April 20, 2020	7,446,363.72
21	Tuesday, April 21, 2020	7,764,338.32
22	Wednesday, April 22, 2020	7,737,230.61
23	Thursday, April 23, 2020	8,138,200.46
24	Friday, April 24, 2020	8,494,695.95
25	Saturday, April 25, 2020	8,494,695.95
26	Sunday, April 26, 2020	8,384,745.35
27	Monday, April 27, 2020	7,908,961.19
28	Tuesday, April 28, 2020	7,968,982.57
29	Wednesday, April 29, 2020	7,882,036.89
30	Thursday, April 30, 2020	7,674,994.06
31	Friday, May 1, 2020	7,623,996.06
32	Saturday, May 2, 2020	7,547,499.06
33	Sunday, May 3, 2020	7,522,000.54
34	Monday, May 4, 2020	6,228,300.64
35	Tuesday, May 5, 2020	6,160,952.88
36	Wednesday, May 6, 2020	5,862,542.15
37	Thursday, May 7, 2020	6,371,299.86
38	Friday, May 8, 2020	5,546,638.31
39	Saturday, May 9, 2020	5,546,638.31
40	Sunday, May 10, 2020	5,442,693.04
41	Monday, May 11, 2020	5,004,236.58
42	Tuesday, May 12, 2020	4,991,766.28
43	Wednesday, May 13, 2020	4,991,552.08
44	Thursday, May 14, 2020	5,307,985.03
45	Friday, May 15, 2020	6,937,809.60
46	Saturday, May 16, 2020	6,937,809.60
47	Sunday, May 17, 2020	6,852,722.81
48	Monday, May 18, 2020	6,484,394.01
49	Tuesday, May 19, 2020	6,582,523.80
50	Wednesday, May 20, 2020	6,575,690.60
51	Thursday, May 21, 2020	6,765,062.54
52	Friday, May 22, 2020	7,126,767.53
53	Saturday, May 23, 2020	7,126,767.53
54	Sunday, May 24, 2020	7,126,767.53

Atmos Energy Corporation-Kentucky
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For the CWC Study Test Year Ended March 31, 2021

CWC WP 2-1

Line No.	Date	Total
55	Monday, May 25, 2020	6,974,063.78
56	Tuesday, May 26, 2020	5,985,820.01
57	Wednesday, May 27, 2020	5,907,552.41
58	Thursday, May 28, 2020	5,810,820.34
59	Friday, May 29, 2020	5,535,068.53
60	Saturday, May 30, 2020	5,535,068.53
61	Sunday, May 31, 2020	5,473,675.14
62	Monday, June 1, 2020	4,721,290.59
63	Tuesday, June 2, 2020	4,551,588.02
64	Wednesday, June 3, 2020	4,418,906.02
65	Thursday, June 4, 2020	4,529,662.63
66	Friday, June 5, 2020	4,618,702.40
67	Saturday, June 6, 2020	4,618,702.40
68	Sunday, June 7, 2020	4,548,218.78
69	Monday, June 8, 2020	3,864,392.92
70	Tuesday, June 9, 2020	2,960,609.41
71	Wednesday, June 10, 2020	2,923,742.33
72	Thursday, June 11, 2020	3,150,434.28
73	Friday, June 12, 2020	4,518,457.40
74	Saturday, June 13, 2020	4,518,457.40
75	Sunday, June 14, 2020	4,459,672.36
76	Monday, June 15, 2020	4,340,268.31
77	Tuesday, June 16, 2020	4,586,291.07
78	Wednesday, June 17, 2020	4,827,192.07
79	Thursday, June 18, 2020	5,011,518.33
80	Friday, June 19, 2020	5,151,878.54
81	Saturday, June 20, 2020	5,151,878.54
82	Sunday, June 21, 2020	5,076,973.97
83	Monday, June 22, 2020	4,792,652.15
84	Tuesday, June 23, 2020	4,858,985.91
85	Wednesday, June 24, 2020	4,942,227.50
86	Thursday, June 25, 2020	5,015,450.97
87	Friday, June 26, 2020	5,039,515.93
88	Saturday, June 27, 2020	5,039,515.93
89	Sunday, June 28, 2020	4,970,426.94
90	Monday, June 29, 2020	4,201,987.34
91	Tuesday, June 30, 2020	3,758,003.27
92	Wednesday, July 1, 2020	3,529,659.92
93	Thursday, July 2, 2020	3,650,127.21
94	Friday, July 3, 2020	3,650,127.21
95	Saturday, July 4, 2020	3,650,127.21
96	Sunday, July 5, 2020	3,447,125.51
97	Monday, July 6, 2020	2,949,191.17
98	Tuesday, July 7, 2020	2,416,875.41
99	Wednesday, July 8, 2020	2,442,815.06
100	Thursday, July 9, 2020	2,616,114.96
101	Friday, July 10, 2020	2,827,514.76
102	Saturday, July 11, 2020	2,827,514.76
103	Sunday, July 12, 2020	2,780,072.29
104	Monday, July 13, 2020	2,417,832.42
105	Tuesday, July 14, 2020	2,568,411.50
106	Wednesday, July 15, 2020	2,697,846.14
107	Thursday, July 16, 2020	2,978,002.28
108	Friday, July 17, 2020	3,271,358.91
109	Saturday, July 18, 2020	3,271,358.91

Atmos Energy Corporation-Kentucky
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For the CWC Study Test Year Ended March 31, 2021

CWC WP 2-1

Line No.	Date	Total
110	Sunday, July 19, 2020	3,219,682.18
111	Monday, July 20, 2020	3,309,048.90
112	Tuesday, July 21, 2020	4,517,982.86
113	Wednesday, July 22, 2020	4,683,645.35
114	Thursday, July 23, 2020	4,904,944.89
115	Friday, July 24, 2020	5,161,157.02
116	Saturday, July 25, 2020	5,161,157.02
117	Sunday, July 26, 2020	5,102,194.05
118	Monday, July 27, 2020	4,784,889.57
119	Tuesday, July 28, 2020	4,806,909.64
120	Wednesday, July 29, 2020	4,575,946.68
121	Thursday, July 30, 2020	4,465,537.83
122	Friday, July 31, 2020	4,351,682.59
123	Saturday, August 1, 2020	4,317,015.62
124	Sunday, August 2, 2020	4,282,348.64
125	Monday, August 3, 2020	3,745,134.97
126	Tuesday, August 4, 2020	3,613,282.84
127	Wednesday, August 5, 2020	3,578,814.20
128	Thursday, August 6, 2020	3,626,126.21
129	Friday, August 7, 2020	3,773,857.35
130	Saturday, August 8, 2020	3,773,857.35
131	Sunday, August 9, 2020	3,722,012.93
132	Monday, August 10, 2020	3,219,503.96
133	Tuesday, August 11, 2020	3,136,752.04
134	Wednesday, August 12, 2020	3,189,188.92
135	Thursday, August 13, 2020	2,849,432.45
136	Friday, August 14, 2020	3,065,839.02
137	Saturday, August 15, 2020	3,065,839.02
138	Sunday, August 16, 2020	3,013,936.10
139	Monday, August 17, 2020	2,798,444.82
140	Tuesday, August 18, 2020	4,085,483.51
141	Wednesday, August 19, 2020	4,531,015.01
142	Thursday, August 20, 2020	4,719,039.34
143	Friday, August 21, 2020	4,964,135.58
144	Saturday, August 22, 2020	4,964,135.58
145	Sunday, August 23, 2020	4,917,512.61
146	Monday, August 24, 2020	4,664,104.67
147	Tuesday, August 25, 2020	4,790,526.85
148	Wednesday, August 26, 2020	4,852,889.43
149	Thursday, August 27, 2020	5,028,215.96
150	Friday, August 28, 2020	4,954,326.54
151	Saturday, August 29, 2020	4,954,326.54
152	Sunday, August 30, 2020	4,884,425.86
153	Monday, August 31, 2020	4,439,920.35
154	Tuesday, September 1, 2020	4,161,700.02
155	Wednesday, September 2, 2020	4,176,007.19
156	Thursday, September 3, 2020	4,248,560.27
157	Friday, September 4, 2020	4,369,952.95
158	Saturday, September 5, 2020	4,369,952.95
159	Sunday, September 6, 2020	4,369,952.95
160	Monday, September 7, 2020	4,197,198.13
161	Tuesday, September 8, 2020	3,510,825.23
162	Wednesday, September 9, 2020	3,416,134.07
163	Thursday, September 10, 2020	2,834,645.51
164	Friday, September 11, 2020	3,094,873.24

Atmos Energy Corporation-Kentucky
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For the CWC Study Test Year Ended March 31, 2021

CWC WP 2-1

Line No.	Date	Total
165	Saturday, September 12, 2020	3,094,873.24
166	Sunday, September 13, 2020	3,055,149.05
167	Monday, September 14, 2020	2,686,280.45
168	Tuesday, September 15, 2020	2,834,653.42
169	Wednesday, September 16, 2020	3,013,900.13
170	Thursday, September 17, 2020	3,247,997.34
171	Friday, September 18, 2020	3,601,302.59
172	Saturday, September 19, 2020	3,601,302.59
173	Sunday, September 20, 2020	3,548,858.66
174	Monday, September 21, 2020	5,051,582.03
175	Tuesday, September 22, 2020	5,145,337.13
176	Wednesday, September 23, 2020	5,215,625.71
177	Thursday, September 24, 2020	5,530,625.45
178	Friday, September 25, 2020	5,752,698.29
179	Saturday, September 26, 2020	5,752,698.29
180	Sunday, September 27, 2020	5,683,066.49
181	Monday, September 28, 2020	5,573,123.76
182	Tuesday, September 29, 2020	5,277,209.60
183	Wednesday, September 30, 2020	5,066,502.88
184	Thursday, October 1, 2020	5,083,586.42
185	Friday, October 2, 2020	5,219,764.23
186	Saturday, October 3, 2020	5,219,764.23
187	Sunday, October 4, 2020	5,156,720.23
188	Monday, October 5, 2020	4,663,061.43
189	Tuesday, October 6, 2020	4,491,779.95
190	Wednesday, October 7, 2020	4,406,522.23
191	Thursday, October 8, 2020	4,573,617.12
192	Friday, October 9, 2020	4,727,520.92
193	Saturday, October 10, 2020	4,727,520.92
194	Sunday, October 11, 2020	4,667,198.97
195	Monday, October 12, 2020	4,475,236.89
196	Tuesday, October 13, 2020	4,506,247.00
197	Wednesday, October 14, 2020	4,700,410.32
198	Thursday, October 15, 2020	5,140,584.17
199	Friday, October 16, 2020	5,483,657.51
200	Saturday, October 17, 2020	5,483,657.51
201	Sunday, October 18, 2020	5,424,151.14
202	Monday, October 19, 2020	5,384,102.69
203	Tuesday, October 20, 2020	5,549,312.87
204	Wednesday, October 21, 2020	5,618,300.43
205	Thursday, October 22, 2020	5,933,326.09
206	Friday, October 23, 2020	6,249,443.38
207	Saturday, October 24, 2020	6,249,443.38
208	Sunday, October 25, 2020	6,155,709.58
209	Monday, October 26, 2020	5,914,936.82
210	Tuesday, October 27, 2020	5,921,626.73
211	Wednesday, October 28, 2020	5,632,510.72
212	Thursday, October 29, 2020	5,543,847.68
213	Friday, October 30, 2020	5,365,067.80
214	Saturday, October 31, 2020	5,329,018.16
215	Sunday, November 1, 2020	5,293,077.05
216	Monday, November 2, 2020	4,692,905.37
217	Tuesday, November 3, 2020	4,520,607.96
218	Wednesday, November 4, 2020	4,514,327.97
219	Thursday, November 5, 2020	5,077,626.22

Atmos Energy Corporation-Kentucky
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For the CWC Study Test Year Ended March 31, 2021

CWC WP 2-1

Line No.	Date	Total
220	Friday, November 6, 2020	4,537,045.80
221	Saturday, November 7, 2020	4,537,045.80
222	Sunday, November 8, 2020	4,457,222.44
223	Monday, November 9, 2020	3,927,226.66
224	Tuesday, November 10, 2020	4,110,732.40
225	Wednesday, November 11, 2020	4,352,732.67
226	Thursday, November 12, 2020	4,773,457.37
227	Friday, November 13, 2020	5,149,023.23
228	Saturday, November 14, 2020	5,149,023.23
229	Sunday, November 15, 2020	5,054,262.08
230	Monday, November 16, 2020	5,097,068.24
231	Tuesday, November 17, 2020	5,511,802.16
232	Wednesday, November 18, 2020	7,862,569.03
233	Thursday, November 19, 2020	8,362,667.88
234	Friday, November 20, 2020	8,908,834.66
235	Saturday, November 21, 2020	8,908,834.66
236	Sunday, November 22, 2020	8,781,547.74
237	Monday, November 23, 2020	8,235,203.40
238	Tuesday, November 24, 2020	8,125,255.81
239	Wednesday, November 25, 2020	7,755,584.65
240	Thursday, November 26, 2020	7,755,584.65
241	Friday, November 27, 2020	7,755,584.65
242	Saturday, November 28, 2020	7,755,584.65
243	Sunday, November 29, 2020	7,443,195.08
244	Monday, November 30, 2020	6,786,623.17
245	Tuesday, December 1, 2020	6,397,038.19
246	Wednesday, December 2, 2020	6,429,063.24
247	Thursday, December 3, 2020	6,885,998.36
248	Friday, December 4, 2020	7,163,889.33
249	Saturday, December 5, 2020	7,163,889.33
250	Sunday, December 6, 2020	7,072,679.68
251	Monday, December 7, 2020	6,031,460.21
252	Tuesday, December 8, 2020	6,178,008.90
253	Wednesday, December 9, 2020	6,165,247.38
254	Thursday, December 10, 2020	6,831,734.81
255	Friday, December 11, 2020	6,348,404.22
256	Saturday, December 12, 2020	6,348,404.22
257	Sunday, December 13, 2020	6,270,975.15
258	Monday, December 14, 2020	8,019,567.87
259	Tuesday, December 15, 2020	8,722,137.69
260	Wednesday, December 16, 2020	9,609,416.05
261	Thursday, December 17, 2020	10,416,763.38
262	Friday, December 18, 2020	10,899,575.89
263	Saturday, December 19, 2020	10,899,575.89
264	Sunday, December 20, 2020	10,771,240.52
265	Monday, December 21, 2020	10,375,485.00
266	Tuesday, December 22, 2020	10,745,720.97
267	Wednesday, December 23, 2020	11,443,344.40
268	Thursday, December 24, 2020	11,443,344.40
269	Friday, December 25, 2020	11,443,344.40
270	Saturday, December 26, 2020	11,443,344.40
271	Sunday, December 27, 2020	11,119,422.13
272	Monday, December 28, 2020	10,369,725.72
273	Tuesday, December 29, 2020	10,496,713.85
274	Wednesday, December 30, 2020	9,878,535.57

Atmos Energy Corporation-Kentucky
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For the CWC Study Test Year Ended March 31, 2021

CWC WP 2-1

Line No.	Date	Total
275	Thursday, December 31, 2020	9,731,589.36
276	Friday, January 1, 2021	9,637,303.36
277	Saturday, January 2, 2021	9,543,017.36
278	Sunday, January 3, 2021	9,448,729.84
279	Monday, January 4, 2021	8,161,126.16
280	Tuesday, January 5, 2021	8,132,637.59
281	Wednesday, January 6, 2021	7,129,376.73
282	Thursday, January 7, 2021	8,474,193.27
283	Friday, January 8, 2021	9,101,680.68
284	Saturday, January 9, 2021	9,101,680.68
285	Sunday, January 10, 2021	8,902,281.05
286	Monday, January 11, 2021	8,082,384.55
287	Tuesday, January 12, 2021	8,970,752.10
288	Wednesday, January 13, 2021	10,097,703.13
289	Thursday, January 14, 2021	11,057,416.85
290	Friday, January 15, 2021	11,969,465.11
291	Saturday, January 16, 2021	11,969,465.11
292	Sunday, January 17, 2021	11,767,969.24
293	Monday, January 18, 2021	11,285,232.91
294	Tuesday, January 19, 2021	12,317,653.39
295	Wednesday, January 20, 2021	14,924,286.94
296	Thursday, January 21, 2021	15,326,109.21
297	Friday, January 22, 2021	16,133,929.67
298	Saturday, January 23, 2021	16,133,929.67
299	Sunday, January 24, 2021	15,899,135.87
300	Monday, January 25, 2021	15,043,036.21
301	Tuesday, January 26, 2021	15,401,671.52
302	Wednesday, January 27, 2021	15,480,915.62
303	Thursday, January 28, 2021	15,077,879.64
304	Friday, January 29, 2021	14,553,179.55
305	Saturday, January 30, 2021	14,432,543.04
306	Sunday, January 31, 2021	14,324,283.63
307	Monday, February 1, 2021	13,465,085.41
308	Tuesday, February 2, 2021	12,409,685.91
309	Wednesday, February 3, 2021	12,361,288.82
310	Thursday, February 4, 2021	13,035,785.74
311	Friday, February 5, 2021	13,477,976.86
312	Saturday, February 6, 2021	13,376,685.26
313	Sunday, February 7, 2021	13,291,108.31
314	Monday, February 8, 2021	12,577,406.32
315	Tuesday, February 9, 2021	12,189,532.35
316	Wednesday, February 10, 2021	12,585,978.27
317	Thursday, February 11, 2021	12,799,937.20
318	Friday, February 12, 2021	15,280,347.81
319	Saturday, February 13, 2021	14,344,361.50
320	Sunday, February 14, 2021	14,248,488.23
321	Monday, February 15, 2021	15,170,636.22
322	Tuesday, February 16, 2021	14,060,878.82
323	Wednesday, February 17, 2021	15,012,127.03
324	Thursday, February 18, 2021	15,717,451.84
325	Friday, February 19, 2021	16,411,050.45
326	Saturday, February 20, 2021	16,306,303.47
327	Sunday, February 21, 2021	16,210,647.92
328	Monday, February 22, 2021	16,398,821.89
329	Tuesday, February 23, 2021	16,222,513.56

Atmos Energy Corporation-Kentucky
Revenue Lag Study - Daily Accts Receivable Balances for Mid-States
For the CWC Study Test Year Ended March 31, 2021

CWC WP 2-1

Line No.	Date	Total
330	Wednesday, February 24, 2021	16,591,229.88
331	Thursday, February 25, 2021	16,064,854.69
332	Friday, February 26, 2021	15,585,456.60
333	Saturday, February 27, 2021	15,450,200.33
334	Sunday, February 28, 2021	15,283,258.74
335	Monday, March 1, 2021	14,762,107.01
336	Tuesday, March 2, 2021	13,903,177.82
337	Wednesday, March 3, 2021	13,703,230.39
338	Thursday, March 4, 2021	13,729,108.01
339	Friday, March 5, 2021	13,859,667.66
340	Saturday, March 6, 2021	13,780,902.27
341	Sunday, March 7, 2021	13,698,798.91
342	Monday, March 8, 2021	12,945,142.79
343	Tuesday, March 9, 2021	12,040,479.92
344	Wednesday, March 10, 2021	11,179,945.26
345	Thursday, March 11, 2021	11,535,625.34
346	Friday, March 12, 2021	12,309,359.70
347	Saturday, March 13, 2021	12,200,676.79
348	Sunday, March 14, 2021	12,108,524.19
349	Monday, March 15, 2021	11,436,395.55
350	Tuesday, March 16, 2021	11,108,099.36
351	Wednesday, March 17, 2021	11,518,400.98
352	Thursday, March 18, 2021	11,958,408.76
353	Friday, March 19, 2021	12,146,664.79
354	Saturday, March 20, 2021	12,068,902.19
355	Sunday, March 21, 2021	11,959,690.05
356	Monday, March 22, 2021	11,388,268.51
357	Tuesday, March 23, 2021	12,920,914.37
358	Wednesday, March 24, 2021	12,907,872.12
359	Thursday, March 25, 2021	12,911,613.06
360	Friday, March 26, 2021	12,607,759.10
361	Saturday, March 27, 2021	12,541,532.98
362	Sunday, March 28, 2021	12,393,528.57
363	Monday, March 29, 2021	11,169,338.26
364	Tuesday, March 30, 2021	9,879,119.77
365	Wednesday, March 31, 2021	8,848,312.42
366		
367	AVERAGE DAILY TOTALS	7,418,295.04
368		
369	KENTUCKY ANNUAL BILLED REVENUE	156,421,195.00 From WP 2-2
370	KENTUCKY AVERAGE DAILY REVENUE	428,551.22
371		
372	REVENUE LAG	17.31

Atmos Energy Corporation-Kentucky
 Revenue Lag Study - Division 009 Kentucky Monthly Revenues
 For the CWC Study Test Year Ended March 31, 2021

CWC WP 2-2

Account Description	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Total
4800 Residential sales	(7,539,761)	(5,682,139)	(4,085,373)	(3,795,243)	(3,743,537)	(3,895,128)	(4,389,566)	(6,573,042)	(10,594,273)	(14,202,977)	(14,243,829)	(12,321,346)	(91,066,215)
4811 Commercial Revenue	(2,955,873)	(1,990,399)	(1,553,177)	(1,536,866)	(1,505,954)	(1,794,458)	(2,081,081)	(2,653,756)	(4,254,595)	(6,033,920)	(6,098,779)	(5,209,682)	(37,668,539)
4812 Industrial Revenue	(488,765)	(227,793)	(148,144)	(134,036)	(148,274)	(448,258)	(170,312)	(286,330)	(503,033)	(691,280)	(786,976)	(540,118)	(4,573,319)
4820 Other Sales to Public Authority	(487,968)	(323,211)	(214,705)	(172,415)	(174,415)	(189,136)	(226,899)	(378,743)	(687,579)	(957,388)	(981,313)	(877,681)	(5,671,453)
4870 Forfeited discounts	140	42	9	7	22	2	7	(18)	97	29	2	11	351
4880 Miscellaneous service revenues	(25,716)	(22,714)	(22,154)	(24,635)	(21,821)	(25,602)	(21,842)	(14,779)	(17,743)	(13,260)	(12,790)	(11,209)	(234,265)
4893 Revenue-Transportation Distrib	(1,220,981)	(1,171,340)	(1,164,146)	(1,076,154)	(1,301,164)	(1,347,395)	(1,507,384)	(1,497,651)	(1,770,467)	(1,839,285)	(1,731,579)	(1,580,211)	(17,207,756)
4895 Revenue-Transportation Commere	-	-	-	-	-	-	-	-	-	-	-	-	-
4896 Revenue-Transportation Industr	-	-	-	-	-	-	-	-	-	-	-	-	-
4930 Rent from Gas Property	-	-	-	-	-	-	-	-	-	-	-	-	-
4950 Other gas revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
Billed Revenue	(12,718,924)	(9,417,554)	(7,187,690)	(6,739,342)	(6,895,143)	(7,699,974)	(8,397,076)	(11,404,318)	(17,827,594)	(23,738,080)	(23,855,264)	(20,540,236)	(156,421,195)
Billed Taxes													-
Billed Revenue plus Taxes	(12,718,924)	(9,417,554)	(7,187,690)	(6,739,342)	(6,895,143)	(7,699,974)	(8,397,076)	(11,404,318)	(17,827,594)	(23,738,080)	(23,855,264)	(20,540,236)	(156,421,195)
4805 Unbilled Residential Revenue	996,945	1,501,189	27,349	13,956	(135,138)	(92,291)	(1,161,190)	(1,605,913)	(2,388,952)	129,739	610,668	2,150,074	46,435
4815 Unbilled Comm Revenue	448,742	563,776	25,766	(20,786)	(46,812)	(27,205)	(511,613)	(468,314)	(968,927)	(221,742)	504,744	748,393	26,022
4816 Unbilled Indus Revenue	163,669	(261,693)	277,180	(6,367)	(295,405)	307,859	(6,832)	(639)	(26,558)	4,536	44,265	(31,411)	168,604
4825 Unbilled Public Authority Reve	57,841	135,962	3,619	1,552	(4,758)	(5,716)	(95,558)	(125,403)	(167,757)	(23,954)	71,882	161,074	8,784
4960 Cost of Service Reserve	-	(382,953)	(459,726)	(432,048)	(91,700)	-	-	-	-	-	-	-	(1,366,427)
Unbilled Revenue	1,667,198	1,556,281	(125,812)	(443,694)	(573,812)	182,647	(1,775,193)	(2,200,270)	(3,552,194)	(111,422)	1,231,560	3,028,129	(1,116,583)
Total Revenue	(11,051,726)	(7,861,272)	(7,313,502)	(7,183,035)	(7,468,956)	(7,517,328)	(10,172,269)	(13,604,588)	(21,379,788)	(23,849,502)	(22,623,704)	(17,512,107)	(157,537,778)

Atmos Energy Corporation-Kentucky
Per Books Purchase Gas Cost
For the CWC Study Test Year Ended March 31, 2021

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.	03/01/20	03/31/20	15.50	04/16/20	16.00	04/20/20	4.00	35.50	\$ 1,239.59	\$ 44,005.45
2	Centerpoint Energy Services Inc	03/01/20	03/31/20	15.50	04/22/20	22.00	04/27/20	5.00	42.50	123,395.44	5,244,306.20
3	Centerpoint Energy Services Inc	03/01/20	03/31/20	15.50	04/23/20	23.00	04/27/20	4.00	42.50	342,296.45	14,547,599.13
4	Har Ken Agent OK	03/01/20	03/31/20	15.50	04/16/20	16.00	04/20/20	4.00	35.50	140.36	4,982.78
5	Midwestern Gas Transmission	03/01/20	03/31/20	15.50	04/14/20	14.00	04/17/20	3.00	32.50	264.29	8,589.43
6	Orbit Gas Transmission Inc	03/01/20	03/31/20	15.50	04/16/20	16.00	05/01/20	15.00	46.50	1,928.84	89,691.06
7	Tennessee Gas Pipeline Co	03/01/20	03/31/20	15.50	04/16/20	16.00	04/23/20	7.00	38.50	374,423.93	14,415,321.31
8	Texas Gas Transmission Corporation	03/01/20	03/31/20	15.50	04/15/20	15.00	04/20/20	5.00	35.50	1,757,354.35	62,386,079.43
9	Trunkline Gas Company, LLC	03/01/20	03/31/20	15.50	04/15/20	15.00	04/20/20	5.00	35.50	32,855.90	1,166,384.45
10	United Energy Trading, LLC	03/01/20	03/31/20	15.50	04/22/20	22.00	04/27/20	5.00	42.50	116,549.35	4,953,347.38
11	Antle Operating Company Inc.	04/01/20	04/30/20	15.00	05/13/20	13.00	05/19/20	6.00	34.00	865.85	29,438.90
12	Centerpoint Energy Services Inc	04/01/20	04/30/20	15.00	05/20/20	20.00	05/26/20	6.00	41.00	42,746.37	1,752,601.17
13	Centerpoint Energy Services Inc	04/01/20	04/30/20	15.00	05/22/20	22.00	05/26/20	4.00	41.00	2,266,111.33	92,910,564.53
14	Har Ken Agent OK	04/01/20	04/30/20	15.00	05/13/20	13.00	05/20/20	7.00	35.00	121.34	4,246.90
15	Midwestern Gas Transmission	04/01/20	04/30/20	15.00	05/07/20	7.00	05/18/20	11.00	33.00	248.20	8,190.60
16	Orbit Gas Transmission Inc	04/01/20	04/30/20	15.00	05/13/20	13.00	05/19/20	6.00	34.00	3,240.73	110,184.82
17	Tennessee Gas Pipeline Co	04/01/20	04/30/20	15.00	05/13/20	13.00	05/22/20	9.00	37.00	269,328.83	9,965,166.71
18	Texas Gas Transmission Corporation	04/01/20	04/30/20	15.00	05/13/20	13.00	05/21/20	8.00	36.00	1,537,917.78	55,365,040.08
19	Trunkline Gas Company, LLC	04/01/20	04/30/20	15.00	05/08/20	8.00	05/20/20	12.00	35.00	6,650.85	232,779.75
20	United Energy Trading, LLC	04/01/20	04/30/20	15.00	05/20/20	20.00	05/26/20	6.00	41.00	379,580.80	15,562,812.80
21	Antle Operating Company Inc.	05/01/20	05/31/20	15.50	06/10/20	10.00	06/24/20	14.00	39.50	1,327.00	52,416.50
22	Har Ken Agent OK	05/01/20	05/31/20	15.50	06/10/20	10.00	06/24/20	14.00	39.50	141.78	5,600.31
23	Midwestern Gas Transmission	05/01/20	05/31/20	15.50	06/12/20	12.00	08/13/20	62.00	89.50	(319.91)	(28,631.95)
24	Orbit Gas Transmission Inc	05/01/20	05/31/20	15.50	06/10/20	10.00	06/24/20	14.00	39.50	5,799.98	229,099.21
25	Symmetry Energy Solutions, LLC	05/01/20	05/31/20	15.50	06/23/20	23.00	06/25/20	2.00	40.50	2,574,090.45	104,250,663.23
26	Symmetry Energy Solutions, LLC	05/01/20	05/31/20	15.50	06/22/20	22.00	06/25/20	3.00	40.50	48,112.12	1,948,540.86
27	Tennessee Gas Pipeline Co	05/01/20	05/31/20	15.50	06/10/20	10.00	06/22/20	12.00	37.50	183,341.93	6,875,322.38
28	Texas Gas Transmission Corporation	05/01/20	05/31/20	15.50	06/16/20	16.00	06/19/20	3.00	34.50	1,249,638.83	43,112,539.64
29	Trunkline Gas Company, LLC	05/01/20	05/31/20	15.50	06/10/20	10.00	06/22/20	12.00	37.50	6,874.85	257,806.88
30	United Energy Trading, LLC	05/01/20	05/31/20	15.50	06/23/20	23.00	06/25/20	2.00	40.50	456,789.58	18,499,977.99
31	Antle Operating Company Inc.	06/01/20	06/30/20	15.00	07/10/20	10.00	07/15/20	5.00	30.00	1,396.45	41,893.50
32	Har Ken Agent OK	06/01/20	06/30/20	15.00	07/10/20	10.00	07/15/20	5.00	30.00	114.61	3,438.30
33	Midwestern Gas Transmission	06/01/20	06/30/20	15.00	07/10/20	10.00	08/13/20	34.00	59.00	(565.16)	(33,344.44)
34	Orbit Gas Transmission Inc	06/01/20	06/30/20	15.00	07/10/20	10.00	07/15/20	5.00	30.00	5,237.87	157,136.10
35	Symmetry Energy Solutions, LLC	06/01/20	06/30/20	15.00	07/22/20	22.00	07/27/20	5.00	42.00	45,614.31	1,915,801.02
36	Symmetry Energy Solutions, LLC	06/01/20	06/30/20	15.00	07/24/20	24.00	07/27/20	3.00	42.00	1,987,746.39	83,485,348.38
37	Tennessee Gas Pipeline Co	06/01/20	06/30/20	15.00	07/13/20	13.00	07/23/20	10.00	38.00	173,787.83	6,603,937.54
38	Texas Gas Transmission Corporation	06/01/20	06/30/20	15.00	07/10/20	10.00	07/20/20	10.00	35.00	1,209,327.90	42,326,476.50
39	Trunkline Gas Company, LLC	06/01/20	06/30/20	15.00	07/10/20	10.00	07/20/20	10.00	35.00	6,652.75	232,846.25
40	United Energy Trading, LLC	06/01/20	06/30/20	15.00	07/22/20	22.00	07/27/20	5.00	42.00	364,122.48	15,293,144.16
41	Antle Operating Company Inc.	07/01/20	07/31/20	15.50	08/20/20	20.00	08/26/20	6.00	41.50	1,413.07	58,642.41
42	Har Ken Agent OK	07/01/20	07/31/20	15.50	08/20/20	20.00	08/26/20	6.00	41.50	138.22	5,736.13
43	Midwestern Gas Transmission	07/01/20	07/31/20	15.50	08/11/20	11.00	08/13/20	2.00	28.50	948.50	27,032.25
44	Orbit Gas Transmission Inc	07/01/20	07/31/20	15.50	08/20/20	20.00	08/26/20	6.00	41.50	7,153.45	296,868.18
45	Symmetry Energy Solutions, LLC	07/01/20	07/31/20	15.50	08/22/20	22.00	08/25/20	3.00	40.50	1,674,023.14	67,797,937.17
46	Symmetry Energy Solutions, LLC	07/01/20	07/31/20	15.50	08/20/20	20.00	08/25/20	5.00	40.50	40,403.77	1,636,352.69
47	Tennessee Gas Pipeline Co	07/01/20	07/31/20	15.50	08/13/20	13.00	08/24/20	11.00	39.50	173,787.83	6,864,619.29
48	Texas Gas Transmission Corporation	07/01/20	07/31/20	15.50	08/12/20	12.00	08/21/20	9.00	36.50	1,249,638.83	45,611,817.30
49	Trunkline Gas Company, LLC	07/01/20	07/31/20	15.50	08/11/20	11.00	08/20/20	9.00	35.50	6,988.74	248,100.27
50	United Energy Trading, LLC	07/01/20	07/31/20	15.50	08/20/20	20.00	08/25/20	5.00	40.50	261,453.46	10,588,865.13
51	Antle Operating Company Inc.	08/01/20	08/31/20	15.50	09/14/20	14.00	09/24/20	10.00	39.50	1,709.10	67,509.45
52	Har Ken Agent OK	08/01/20	08/31/20	15.50	09/14/20	14.00	09/28/20	14.00	43.50	154.04	6,700.74
53	Midwestern Gas Transmission	08/01/20	08/31/20	15.50	09/14/20	14.00	09/18/20	4.00	33.50	(1,918.76)	(64,278.46)

Atmos Energy Corporation-Kentucky
Per Books Purchase Gas Cost
For the CWC Study Test Year Ended March 31, 2021

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)
54	Orbit Gas Transmission Inc	08/01/20	08/31/20	15.50	09/14/20	14.00	09/24/20	10.00	39.50	7,527.18	297,323.61
55	Symmetry Energy Solutions, LLC	08/01/20	08/31/20	15.50	09/24/20	24.00	09/25/20	1.00	40.50	2,384,628.50	96,577,454.25
56	Symmetry Energy Solutions, LLC	08/01/20	08/31/20	15.50	09/22/20	22.00	09/25/20	3.00	40.50	64,856.56	2,626,690.68
57	Tennessee Gas Pipeline Co	08/01/20	08/31/20	15.50	09/16/20	16.00	09/21/20	5.00	36.50	173,787.83	6,343,255.80
58	Texas Gas Transmission Corporation	08/01/20	08/31/20	15.50	09/14/20	14.00	09/21/20	7.00	36.50	1,249,638.83	45,611,817.30
59	Trunkline Gas Company, LLC	08/01/20	08/31/20	15.50	09/14/20	14.00	09/21/20	7.00	36.50	7,111.46	259,568.29
60	United Energy Trading, LLC	08/01/20	08/31/20	15.50	09/22/20	22.00	09/25/20	3.00	40.50	356,875.40	14,453,453.70
61	Antle Operating Company Inc.	09/01/20	09/30/20	15.00	10/21/20	21.00	10/23/20	2.00	38.00	1,948.91	74,058.58
62	Har Ken Agent OK	09/01/20	09/30/20	15.00	10/21/20	21.00	10/26/20	5.00	41.00	161.07	6,603.87
63	Midwestern Gas Transmission	09/01/20	09/30/20	15.00	10/13/20	13.00	10/16/20	3.00	31.00	(1,253.61)	(38,861.91)
64	Orbit Gas Transmission Inc	09/01/20	09/30/20	15.00	10/21/20	21.00	10/23/20	2.00	38.00	8,245.17	313,316.46
65	Symmetry Energy Solutions, LLC	09/01/20	09/30/20	15.00	10/23/20	23.00	10/26/20	3.00	41.00	3,157,938.54	129,475,480.14
66	Symmetry Energy Solutions, LLC	09/01/20	09/30/20	15.00	10/21/20	21.00	10/26/20	5.00	41.00	70,129.10	2,875,293.10
67	Tennessee Gas Pipeline Co	09/01/20	09/30/20	15.00	10/14/20	14.00	10/22/20	8.00	37.00	173,787.83	6,430,149.71
68	Texas Gas Transmission Corporation	09/01/20	09/30/20	15.00	10/14/20	14.00	10/19/20	5.00	34.00	1,209,327.90	41,117,148.60
69	Trunkline Gas Company, LLC	09/01/20	09/30/20	15.00	10/14/20	14.00	10/20/20	6.00	35.00	6,655.34	232,936.90
70	United Energy Trading, LLC	09/01/20	09/30/20	15.00	10/22/20	22.00	10/26/20	4.00	41.00	547,815.43	22,460,432.63
71	Antle Operating Company Inc.	10/01/20	10/31/20	15.50	11/18/20	18.00	11/24/20	6.00	39.50	1,385.88	54,742.26
72	Har Ken Agent OK	10/01/20	10/31/20	15.50	11/19/20	19.00	11/25/20	6.00	40.50	5.52	223.56
73	Midwestern Gas Transmission	10/01/20	10/31/20	15.50	11/13/20	13.00	11/17/20	4.00	32.50	1,361.65	44,253.63
74	Orbit Gas Transmission Inc	10/01/20	10/31/20	15.50	11/18/20	18.00	11/24/20	6.00	39.50	4,526.99	178,816.11
75	Symmetry Energy Solutions, LLC	10/01/20	10/31/20	15.50	11/23/20	23.00	11/25/20	2.00	40.50	56,255.65	2,278,353.83
76	Symmetry Energy Solutions, LLC	10/01/20	10/31/20	15.50	11/23/20	23.00	11/25/20	2.00	40.50	3,353,437.91	135,814,235.36
77	Tennessee Gas Pipeline Co	10/01/20	10/31/20	15.50	11/12/20	12.00	11/23/20	11.00	38.50	192,896.03	7,426,497.16
78	Texas Gas Transmission Corporation	10/01/20	10/31/20	15.50	11/12/20	12.00	11/20/20	8.00	35.50	1,640,658.26	58,243,368.23
79	Trunkline Gas Company, LLC	10/01/20	10/31/20	15.50	11/13/20	13.00	11/20/20	7.00	35.50	6,877.16	244,139.18
80	United Energy Trading, LLC	10/01/20	10/31/20	15.50	11/23/20	23.00	11/25/20	2.00	40.50	540,810.98	21,902,844.69
81	Antle Operating Company Inc.	11/01/20	11/30/20	15.00	12/16/20	16.00	12/18/20	2.00	33.00	2,201.80	72,659.40
82	Midwestern Gas Transmission	11/01/20	11/30/20	15.00	12/15/20	15.00	12/17/20	2.00	32.00	(781.61)	(25,011.52)
83	Orbit Gas Transmission Inc	11/01/20	11/30/20	15.00	12/16/20	16.00	12/18/20	2.00	33.00	4,396.75	145,092.75
84	Symmetry Energy Solutions, LLC	11/01/20	11/30/20	15.00	12/19/20	19.00	12/28/20	9.00	43.00	777,867.91	33,448,320.13
85	Symmetry Energy Solutions, LLC	11/01/20	11/30/20	15.00	12/19/20	19.00	12/28/20	9.00	43.00	267,759.90	11,513,675.70
86	Tennessee Gas Pipeline Co	11/01/20	11/30/20	15.00	12/11/20	11.00	12/21/20	10.00	36.00	369,223.65	13,292,051.40
87	Texas Gas Transmission Corporation	11/01/20	11/30/20	15.00	12/10/20	10.00	12/21/20	11.00	36.00	1,691,401.50	60,890,454.00
88	Trunkline Gas Company, LLC	11/01/20	11/30/20	15.00	12/15/20	15.00	12/21/20	6.00	36.00	32,447.20	1,168,099.20
89	United Energy Trading, LLC	11/01/20	11/30/20	15.00	12/19/20	19.00	12/28/20	9.00	43.00	104,781.66	4,505,611.38
90	Antle Operating Company Inc.	12/01/20	12/31/20	15.50	01/29/21	29.00	01/29/21	-	44.50	729.73	32,472.99
91	Midwestern Gas Transmission	12/01/20	12/31/20	15.50	01/11/21	11.00	01/14/21	3.00	29.50	(955.30)	(28,181.35)
92	Orbit Gas Transmission Inc	12/01/20	12/31/20	15.50	01/13/21	13.00	01/22/21	9.00	37.50	496.41	18,615.38
93	Symmetry Energy Solutions, LLC	12/01/20	12/31/20	15.50	01/21/21	21.00	01/25/21	4.00	40.50	2,970,779.18	120,316,556.79
94	Symmetry Energy Solutions, LLC	12/01/20	12/31/20	15.50	01/21/21	21.00	01/25/21	4.00	40.50	222,259.03	9,001,490.72
95	Tennessee Gas Pipeline Co	12/01/20	12/31/20	15.50	01/13/21	13.00	01/25/21	12.00	40.50	378,592.55	15,332,998.28
96	Texas Gas Transmission Corporation	12/01/20	12/31/20	15.50	01/12/21	12.00	01/22/21	10.00	37.50	1,747,781.55	65,541,808.13
97	Trunkline Gas Company, LLC	12/01/20	12/31/20	15.50	01/11/21	11.00	01/20/21	9.00	35.50	33,022.98	1,172,315.79
98	United Energy Trading, LLC	12/01/20	12/31/20	15.50	01/21/21	21.00	01/25/21	4.00	40.50	406,786.90	16,474,869.45
99	Antle Operating Company Inc.	01/01/21	01/31/21	15.50	02/16/21	16.00	02/18/21	2.00	33.50	2,244.86	75,202.81
100	Midwestern Gas Transmission	01/01/21	01/31/21	15.50	02/09/21	9.00	02/10/21	1.00	25.50	(359.76)	(9,173.88)
101	Orbit Gas Transmission Inc	01/01/21	01/31/21	15.50	02/16/21	16.00	02/18/21	2.00	33.50	394.62	13,219.77
102	Symmetry Energy Solutions, LLC	01/01/21	01/31/21	15.50	02/23/21	23.00	02/25/21	2.00	40.50	2,757,594.02	111,682,557.81
103	Symmetry Energy Solutions, LLC	01/01/21	01/31/21	15.50	02/23/21	23.00	02/25/21	2.00	40.50	189,505.65	7,674,978.83
104	Tennessee Gas Pipeline Co	01/01/21	01/31/21	15.50	02/11/21	11.00	02/22/21	11.00	37.50	378,592.55	14,197,220.63
105	Texas Gas Transmission Corporation	01/01/21	01/31/21	15.50	02/11/21	11.00	02/19/21	8.00	34.50	1,747,781.55	60,298,463.48
106	Trunkline Gas Company, LLC	01/01/21	01/31/21	15.50	02/16/21	16.00	02/22/21	6.00	37.50	33,961.83	1,273,568.63
107	United Energy Trading, LLC	01/01/21	01/31/21	15.50	02/23/21	23.00	02/25/21	2.00	40.50	363,593.79	14,725,548.50

Atmos Energy Corporation-Kentucky
Per Books Purchase Gas Cost
For the CWC Study Test Year Ended March 31, 2021

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)
108	Antle Operating Company Inc.	02/01/21	02/28/21	14.00	03/17/21	17.00	03/18/21	1.00	32.00	3,098.75	99,160.00
109	Midwestern Gas Transmission	02/01/21	02/28/21	14.00	03/10/21	10.00	03/15/21	5.00	29.00	5,812.01	168,548.29
110	Orbit Gas Transmission Inc	02/01/21	02/28/21	14.00	03/17/21	17.00	03/18/21	1.00	32.00	1,698.27	54,344.64
111	Symmetry Energy Solutions, LLC	02/01/21	02/28/21	14.00	03/24/21	24.00	03/25/21	1.00	39.00	4,639,691.29	180,947,960.31
112	Symmetry Energy Solutions, LLC	02/01/21	02/28/21	14.00	03/23/21	23.00	03/25/21	2.00	39.00	499,067.83	19,463,645.37
113	Tennessee Gas Pipeline Co	02/01/21	02/28/21	14.00	03/11/21	11.00	03/22/21	11.00	36.00	378,592.55	13,629,331.80
114	Texas Gas Transmission Corporation	02/01/21	02/28/21	14.00	03/11/21	11.00	03/19/21	8.00	33.00	1,578,641.40	52,095,166.20
115	Trunkline Gas Company, LLC	02/01/21	02/28/21	14.00	03/17/21	17.00	03/22/21	5.00	36.00	29,235.86	1,052,490.96
116	United Energy Trading, LLC	02/01/21	02/28/21	14.00	03/24/21	24.00	03/25/21	1.00	39.00	850,698.50	33,177,241.50
124											
125										<u>\$56,678,421.00</u>	<u>\$ 2,195,974,218.00</u>
126											
127											<u>38.74</u>
											To Schedule 1, Line 3

Atmos Energy Corporation-Kentucky
 Payroll Lead Days
 For the CWC Study Test Year Ended March 31, 2021

ATO-CWC4

Line No.	Start Morning of 1st day of Pay Period (a)	End Evening of Last Day of Pay Period (b)	No. of Days (c)	Service Lag (d)	Date Paid (e)	Payment Lag (f)	Total Direct Payroll Lag (g)
1	03/21/20	04/03/20	14.00	7.00	04/10/20	7.00	14.00
2	04/04/20	04/17/20	14.00	7.00	04/24/20	7.00	14.00
3	04/18/20	05/01/20	14.00	7.00	05/08/20	7.00	14.00
4	05/02/20	05/15/20	14.00	7.00	05/22/20	7.00	14.00
5	05/16/20	05/29/20	14.00	7.00	06/05/20	7.00	14.00
6	05/30/20	06/12/20	14.00	7.00	06/19/20	7.00	14.00
7	06/13/20	06/26/20	14.00	7.00	07/03/20	7.00	14.00
8	06/27/20	07/10/20	14.00	7.00	07/17/20	7.00	14.00
9	07/11/20	07/24/20	14.00	7.00	07/31/20	7.00	14.00
10	07/25/20	08/07/20	14.00	7.00	08/14/20	7.00	14.00
11	08/08/20	08/21/20	14.00	7.00	08/28/20	7.00	14.00
12	08/22/20	09/04/20	14.00	7.00	09/11/20	7.00	14.00
13	09/05/20	09/18/20	14.00	7.00	09/25/20	7.00	14.00
14	09/19/20	10/02/20	14.00	7.00	10/09/20	7.00	14.00
15	10/03/20	10/16/20	14.00	7.00	10/23/20	7.00	14.00
16	10/17/20	10/30/20	14.00	7.00	11/06/20	7.00	14.00
17	10/31/20	11/13/20	14.00	7.00	11/20/20	7.00	14.00
18	11/14/20	11/27/20	14.00	7.00	12/04/20	7.00	14.00
19	11/28/20	12/11/20	14.00	7.00	12/18/20	7.00	14.00
20	12/12/20	12/25/20	14.00	7.00	12/31/20	6.00	13.00
21	12/26/20	01/08/21	14.00	7.00	01/15/21	7.00	14.00
22	01/09/21	01/22/21	14.00	7.00	01/29/21	7.00	14.00
23	01/23/21	02/05/21	14.00	7.00	02/12/21	7.00	14.00
24	02/06/21	02/19/21	14.00	7.00	02/26/21	7.00	14.00
25	02/20/21	03/05/21	14.00	7.00	03/12/21	7.00	14.00
26	03/06/21	03/19/21	14.00	7.00	03/26/21	7.00	14.00
27	03/20/21	04/02/21	14.00	7.00	04/09/21	7.00	14.00
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	06/05/20	0		0.00%		0.00
36	Next day	06/08/20	3		5.26%		0.16
37	2 days	06/09/20	4		31.58%		1.26
38	3-7 days	6/10/20-6/14/20	9		36.84%		3.32
39	8-14 days	6/15/2020-6/21/20	16		10.53%		1.68
40	> 2 weeks	06/22/20	23		15.79%		3.63
41							
42	Total Payroll Check Lag						10.05
43							
44	% of Payroll Checks						0.82%
45							
46	WEIGHTED AVERAGE OF ACTUAL PAYROLL CHECKS						0.08
47							
48	TOTAL PAYROLL LAG						14.08
49							
50	Period: 05/16/20 to 05/29/20 Paydate 06/5/2020						

ATO-CWC5

**Atmos Energy Corporation-Kentucky
 Other O&M Payment Lag
 For the CWC Study Test Year Ended March 31, 2021**

Line No.	Description	Weighted \$ Days
	<i>a</i>	<i>b</i>
1	Other O&M Payment Lag Days:	25.53
2		
3	Check Clearing Lag Days:	<u>2.53</u>
4		
5	Total O&M Payment Lag Days:	<u><u>28.06</u></u>

Atmos Energy Corporation-Kentucky
 Other O&M Payment and Check Clearing Lag
 For the CWC Study Test Year Ended March 31, 2021

CWC WP 5-1

Line No.	Vendor	Invoice Date	Invoice Amount	Division 009 Amount	Payment Type	Service Period From	Service Period To	Midpoint Service Service	Date Paid	Payment lag	Weighted Payment Lag	Date Cleared	Clearing Lag	Weighted Clearing Lag
		<i>a</i>	<i>b</i>	<i>c</i>	<i>d</i>	<i>e</i>	<i>f</i>	<i>g</i>	<i>h</i>	<i>i</i>	$= i - (h \text{ or } b)$	<i>j</i>	$m = (l - j)$	$n = (m * d)$
1	ACTION PEST CONTROL INC	5-Oct-20	74	74	CHECK	5-Oct-20	5-Oct-20	5-Oct-20	2-Nov-20	28	2,072	9-Nov-20	7	518
2	AIRGAS USA LLC	29-May-19	45	45	CHECK	29-May-20	29-May-20	29-May-20	18-May-20	(11)	(492)	26-May-20	8	358
3	AIRGAS USA LLC	14-May-20	512	512	Direct Deposit	14-May-20	14-May-20	14-May-20	8-Jun-20	25	12,800	8-Jun-20	0	-
4	AIRGAS USA LLC	31-May-20	28	28	Direct Deposit	1-May-20	31-May-20	16-May-20	25-Jun-20	40	1,104	25-Jun-20	0	-
5	AIRGAS USA LLC	29-Jun-20	2,025	2,025	CHECK	29-Jun-20	29-Jun-20	29-Jun-20	27-Jul-20	28	56,689	3-Aug-20	7	14,172
6	AIRGAS USA LLC	30-Nov-20	51	51	Direct Deposit	1-Nov-20	30-Nov-20	15-Nov-20	28-Dec-20	43	2,184	28-Dec-20	0	-
7	AIRGAS USA LLC	3-Dec-20	104	104	Direct Deposit	3-Dec-20	3-Dec-20	3-Dec-20	28-Dec-20	25	2,589	28-Dec-20	0	-
8	ALLIANCE CONSULTING GROUP	31-Mar-20	796	796	Direct Deposit	1-Mar-20	31-Mar-20	16-Mar-20	29-Apr-20	44	35,006	29-Apr-20	0	-
9	AMBERS FACILITY MAINTENANCE	23-Mar-20	83	83	CHECK	23-Mar-20	23-Mar-20	23-Mar-20	20-Apr-20	28	2,337	1-May-20	11	918
10	AMBERS FACILITY MAINTENANCE	1-May-20	318	318	CHECK	1-Apr-20	30-Apr-20	15-Apr-20	27-May-20	42	13,356	8-Jun-20	12	3,816
11	AMBERS FACILITY MAINTENANCE	30-May-20	69	69	CHECK	30-May-20	30-May-20	30-May-20	24-Jun-20	25	1,723	8-Jul-20	14	965
12	AMBERS FACILITY MAINTENANCE	10-Jun-20	122	122	CHECK	10-Jun-20	10-Jun-20	10-Jun-20	6-Jul-20	26	3,169	17-Jul-20	11	1,341
13	AMBERS FACILITY MAINTENANCE	12-Jun-20	101	101	CHECK	12-Jun-20	12-Jun-20	12-Jun-20	8-Jul-20	26	2,624	4-Aug-20	27	2,725
14	AMBERS FACILITY MAINTENANCE	24-Jun-20	122	122	CHECK	24-Jun-20	24-Jun-20	24-Jun-20	20-Jul-20	26	3,169	3-Aug-20	14	1,707
15	AMBERS FACILITY MAINTENANCE	1-Jul-20	919	919	CHECK	1-Jun-20	30-Jun-20	15-Jun-20	27-Jul-20	42	38,599	28-Aug-20	32	29,409
16	AMBERS FACILITY MAINTENANCE	31-Oct-20	34	34	CHECK	31-Oct-20	31-Oct-20	31-Oct-20	25-Nov-20	25	859	8-Dec-20	13	446
17	AMBERS FACILITY MAINTENANCE	1-Mar-21	919	919	CHECK	1-Feb-21	28-Feb-21	14-Feb-21	29-Mar-21	43	39,518	13-Apr-21	15	13,785
18	ARKEMA INC	26-May-20	3,906	4,140	Direct Deposit	26-May-20	26-May-20	26-May-20	22-Jun-20	27	111,793	22-Jun-20	0	-
19	ARKEMA INC	11-Jan-21	1,845	1,955	Direct Deposit	11-Jan-21	11-Jan-21	11-Jan-21	5-Feb-21	25	48,885	5-Feb-21	0	-
20	AT&T	28-Apr-20	383	383	CHECK	25-Mar-20	25-Mar-20	25-Mar-20	4-May-20	40	15,320	13-May-20	9	3,447
21	AT&T	1-Sep-20	156	70	CHECK	1-Aug-20	1-Sep-20	16-Aug-20	14-Sep-20	29	2,030	23-Sep-20	9	630
22	AT&T	1-Dec-20	302	302	CHECK	1-Nov-20	1-Dec-20	16-Nov-20	16-Dec-20	30	9,071	24-Dec-20	8	2,419
23	AT&T	1-Jan-21	121,520	5,725	CHECK	1-Dec-20	1-Jan-21	16-Dec-20	18-Jan-21	33	188,914	25-Jan-21	7	40,073
24	AT&T	1-Mar-21	306	306	CHECK	1-Feb-21	1-Mar-21	15-Feb-21	17-Mar-21	30	9,191	23-Mar-21	6	1,838
25	AT&T MOBILITY	12-Apr-20	39,491	50	CHECK	12-Mar-20	12-Apr-20	27-Mar-20	4-May-20	38	1,917	15-May-20	11	555
26	AT&T MOBILITY	12-May-20	7,680	4,510	CHECK	12-Apr-20	12-May-20	27-Apr-20	1-Jun-20	35	157,835	12-Jun-20	11	49,605
27	AT&T MOBILITY	12-Jun-20	423	5,248	CHECK	12-May-20	12-Jun-20	27-May-20	1-Jul-20	35	183,673	14-Jul-20	13	68,221
28	ATMOS ENERGY CORPORATION	10-Jun-20	56	56	Direct Deposit	10-May-20	9-Jun-20	25-May-20	18-Jun-20	24	1,349	18-Jun-20	0	-
29	ATMOS ENERGY CORPORATION	10-Aug-20	2	2	Direct Deposit	10-Jul-20	9-Aug-20	25-Jul-20	12-Aug-20	18	33	12-Aug-20	0	-
30	ATMOS ENERGY CORPORATION	9-Oct-20	12	12	Direct Deposit	9-Sep-20	8-Oct-20	23-Sep-20	15-Oct-20	22	257	15-Oct-20	0	-
31	ATMOS ENERGY CORPORATION	10-Dec-20	7	7	Direct Deposit	10-Nov-20	9-Dec-20	24-Nov-20	17-Dec-20	23	167	17-Dec-20	0	-
32	ATMOS ENERGY CORPORATION	8-Jan-21	41	41	Direct Deposit	8-Dec-20	7-Jan-21	23-Dec-20	14-Jan-21	22	902	14-Jan-21	0	-
33	ATMOS ENERGY CORPORATION	8-Jan-21	126	126	Direct Deposit	8-Dec-20	7-Jan-21	23-Dec-20	14-Jan-21	22	2,780	14-Jan-21	0	-
34	ATMOS ENERGY CORPORATION	10-Feb-21	130	130	Direct Deposit	10-Jan-21	9-Feb-21	25-Jan-21	22-Feb-21	28	3,646	22-Feb-21	0	-
35	ATMOS ENERGY CORPORATION	10-Mar-21	218	218	Direct Deposit	10-Feb-21	9-Mar-21	23-Feb-21	15-Mar-21	20	4,361	15-Mar-21	0	-
36	AUTOMOTIVE RESOURCES INTERNATI	8-Sep-20	2,059,700	108,251	Direct Deposit	1-Aug-20	31-Aug-20	16-Aug-20	10-Sep-20	25	2,706,286	10-Sep-20	0	-
37	AUTOMOTIVE RESOURCES INTERNATI	5-Oct-20	2,278,632	164,215	Direct Deposit	1-Sep-20	30-Sep-20	15-Sep-20	6-Oct-20	21	3,448,514	6-Oct-20	0	-
38	B GREEN LAWN CARE	15-Jun-20	41	41	CHECK	15-Jun-20	15-Jun-20	15-Jun-20	29-Jun-20	14	571	14-Jul-20	15	612
39	BANK OF AMERICA	16-Apr-20	269	269	EFT	20-Mar-20	25-Mar-20	22-Mar-20	30-Apr-20	39	10,500	30-Apr-20	0	-
40	BANK OF AMERICA	16-Apr-20	10	10	EFT	24-Mar-20	24-Mar-20	24-Mar-20	30-Apr-20	37	370	30-Apr-20	0	-
41	BANK OF AMERICA	16-Apr-20	131	131	EFT	31-Mar-20	31-Mar-20	31-Mar-20	30-Apr-20	30	3,934	30-Apr-20	0	-
42	BANK OF AMERICA	16-Apr-20	92	92	EFT	27-Mar-20	27-Mar-20	27-Mar-20	30-Apr-20	34	3,113	30-Apr-20	0	-
43	BANK OF AMERICA	16-Apr-20	2,493	2,493	EFT	1-Apr-20	2-Apr-20	1-Apr-20	30-Apr-20	29	72,300	30-Apr-20	0	-
44	BANK OF AMERICA	16-Apr-20	183	183	EFT	17-Mar-20	9-Apr-20	28-Mar-20	30-Apr-20	33	6,030	30-Apr-20	0	-
45	BANK OF AMERICA	16-Apr-20	656	656	EFT	18-Mar-20	15-Apr-20	1-Apr-20	30-Apr-20	29	19,034	30-Apr-20	0	-
46	BANK OF AMERICA	16-May-20	150	150	EFT	28-Apr-20	28-Apr-20	28-Apr-20	29-May-20	31	4,650	29-May-20	0	-
47	BANK OF AMERICA	16-May-20	30	30	EFT	28-Apr-20	14-May-20	6-May-20	29-May-20	23	682	29-May-20	0	-
48	BANK OF AMERICA	16-May-20	252	74	EFT	17-Apr-20	7-May-20	27-Apr-20	29-May-20	32	2,374	29-May-20	0	-
49	BANK OF AMERICA	16-May-20	30	30	EFT	7-May-20	7-May-20	7-May-20	29-May-20	22	667	29-May-20	0	-
50	BANK OF AMERICA	16-May-20	183	183	EFT	29-Apr-20	8-May-20	3-May-20	29-May-20	26	4,748	29-May-20	0	-
51	BANK OF AMERICA	16-May-20	91	51	EFT	15-Apr-20	4-May-20	24-Apr-20	29-May-20	35	1,778	29-May-20	0	-
52	BANK OF AMERICA	16-May-20	78	78	EFT	20-Apr-20	8-May-20	29-Apr-20	29-May-20	30	2,342	29-May-20	0	-
53	BANK OF AMERICA	16-May-20	274	195	EFT	17-Apr-20	13-May-20	30-Apr-20	29-May-20	29	5,643	29-May-20	0	-

**Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For the CWC Study Test Year Ended March 31, 2021**

CWC WP 5-1

Line No.	Vendor	Invoice	Invoice	Division 009	Payment	Service Period		Midpoint	Date	Payment	Weighted	Date	Clearing	Weighted
		Date	Amount	Amount	Type	From	To	Service			Service			
54	BANK OF AMERICA	16-May-20	32	32	EFT	10-May-20	10-May-20	10-May-20	29-May-20	19	604	29-May-20	0	-
55	BANK OF AMERICA	16-May-20	217	74	EFT	16-Apr-20	13-May-20	29-Apr-20	29-May-20	30	2,226	29-May-20	0	-
56	BANK OF AMERICA	16-Jun-20	60	60	EFT	2-Jun-20	5-Jun-20	3-Jun-20	30-Jun-20	27	1,630	30-Jun-20	0	-
57	BANK OF AMERICA	16-Jun-20	110	110	EFT	9-Jun-20	9-Jun-20	9-Jun-20	30-Jun-20	21	2,312	30-Jun-20	0	-
58	BANK OF AMERICA	16-Jun-20	190	190	EFT	19-May-20	6-Jun-20	28-May-20	30-Jun-20	33	6,278	30-Jun-20	0	-
59	BANK OF AMERICA	16-Jun-20	22	22	EFT	11-Jun-20	11-Jun-20	11-Jun-20	30-Jun-20	19	413	30-Jun-20	0	-
60	BANK OF AMERICA	16-Jun-20	137	137	EFT	14-May-20	28-May-20	21-May-20	30-Jun-20	40	5,476	30-Jun-20	0	-
61	BANK OF AMERICA	16-Jun-20	156	156	EFT	14-May-20	9-Jun-20	27-May-20	30-Jun-20	34	5,300	30-Jun-20	0	-
62	BANK OF AMERICA	16-Jun-20	235	235	EFT	8-Jun-20	14-Jun-20	11-Jun-20	30-Jun-20	19	4,468	30-Jun-20	0	-
63	BANK OF AMERICA	16-Jun-20	59	59	EFT	10-Jun-20	10-Jun-20	10-Jun-20	30-Jun-20	20	1,188	30-Jun-20	0	-
64	BANK OF AMERICA	16-Jun-20	262	262	EFT	15-May-20	4-Jun-20	25-May-20	30-Jun-20	36	9,431	30-Jun-20	0	-
65	BANK OF AMERICA	16-Jun-20	88	13	EFT	18-May-20	26-May-20	22-May-20	30-Jun-20	39	496	30-Jun-20	0	-
66	BANK OF AMERICA	16-Jul-20	21	21	EFT	9-Jul-20	9-Jul-20	9-Jul-20	31-Jul-20	22	466	31-Jul-20	0	-
67	BANK OF AMERICA	16-Jul-20	273	273	EFT	28-Jun-20	7-Jul-20	2-Jul-20	31-Jul-20	29	7,911	31-Jul-20	0	-
68	BANK OF AMERICA	16-Jul-20	830	777	EFT	15-Jun-20	16-Jul-20	30-Jun-20	31-Jul-20	31	24,098	31-Jul-20	0	-
69	BANK OF AMERICA	16-Jul-20	49	27	EFT	9-Jul-20	15-Jul-20	12-Jul-20	31-Jul-20	19	522	31-Jul-20	0	-
70	BANK OF AMERICA	16-Jul-20	634	634	EFT	30-Jun-20	6-Jul-20	3-Jul-20	31-Jul-20	28	17,763	31-Jul-20	0	-
71	BANK OF AMERICA	16-Jul-20	16	16	EFT	25-Jun-20	25-Jun-20	25-Jun-20	31-Jul-20	36	568	31-Jul-20	0	-
72	BANK OF AMERICA	16-Jul-20	539	463	EFT	22-Apr-20	7-Jul-20	30-May-20	31-Jul-20	62	28,718	31-Jul-20	0	-
73	BANK OF AMERICA	16-Jul-20	416	326	EFT	16-Jun-20	31-Jul-20	8-Jul-20	31-Jul-20	23	7,501	31-Jul-20	0	-
74	BANK OF AMERICA	16-Jul-20	434	409	EFT	16-Jun-20	13-Jul-20	29-Jun-20	31-Jul-20	32	13,084	31-Jul-20	0	-
75	BANK OF AMERICA	16-Jul-20	86	86	EFT	23-Jun-20	26-Jun-20	24-Jun-20	31-Jul-20	37	3,175	31-Jul-20	0	-
76	BANK OF AMERICA	16-Jul-20	196	196	EFT	16-Jun-20	25-Jun-20	20-Jun-20	31-Jul-20	41	8,031	31-Jul-20	0	-
77	BANK OF AMERICA	16-Jul-20	379	379	EFT	23-Jun-20	15-Jul-20	4-Jul-20	31-Jul-20	27	10,244	31-Jul-20	0	-
78	BANK OF AMERICA	16-Jul-20	414	414	EFT	7-Jul-20	14-Jul-20	10-Jul-20	31-Jul-20	21	8,687	31-Jul-20	0	-
79	BANK OF AMERICA	16-Aug-20	2,232	1,830	EFT	16-Jul-20	11-Aug-20	29-Jul-20	31-Aug-20	33	60,387	31-Aug-20	0	-
80	BANK OF AMERICA	16-Aug-20	23	23	EFT	23-Jul-20	5-Aug-20	29-Jul-20	31-Aug-20	33	761	31-Aug-20	0	-
81	BANK OF AMERICA	16-Aug-20	430	401	EFT	22-Jul-20	18-Aug-20	4-Aug-20	31-Aug-20	27	10,823	31-Aug-20	0	-
82	BANK OF AMERICA	16-Aug-20	93	93	EFT	6-Aug-20	12-Aug-20	9-Aug-20	31-Aug-20	22	2,043	31-Aug-20	0	-
83	BANK OF AMERICA	16-Aug-20	37	37	EFT	18-Jul-20	5-Aug-20	27-Jul-20	31-Aug-20	35	1,304	31-Aug-20	0	-
84	BANK OF AMERICA	16-Sep-20	221	221	EFT	19-Aug-20	8-Sep-20	29-Aug-20	30-Sep-20	32	7,079	30-Sep-20	0	-
85	BANK OF AMERICA	16-Sep-20	15	15	EFT	2-Sep-20	2-Sep-20	2-Sep-20	30-Sep-20	28	420	30-Sep-20	0	-
86	BANK OF AMERICA	16-Sep-20	186	186	EFT	18-Aug-20	28-Aug-20	23-Aug-20	30-Sep-20	38	7,067	30-Sep-20	0	-
87	BANK OF AMERICA	16-Sep-20	127	91	EFT	23-Aug-20	15-Sep-20	3-Sep-20	30-Sep-20	27	2,459	30-Sep-20	0	-
88	BANK OF AMERICA	16-Sep-20	32	32	EFT	15-Aug-20	16-Sep-20	31-Aug-20	30-Sep-20	30	954	30-Sep-20	0	-
89	BANK OF AMERICA	16-Sep-20	265	265	EFT	9-Sep-20	9-Sep-20	9-Sep-20	30-Sep-20	21	5,555	30-Sep-20	0	-
90	BANK OF AMERICA	16-Oct-20	153	122	EFT	29-Sep-20	7-Oct-20	3-Oct-20	30-Oct-20	27	3,301	30-Oct-20	0	-
91	BANK OF AMERICA	16-Oct-20	262	262	EFT	1-Oct-20	6-Oct-20	3-Oct-20	30-Oct-20	27	7,076	30-Oct-20	0	-
92	BANK OF AMERICA	16-Oct-20	61	61	EFT	4-Oct-20	15-Oct-20	9-Oct-20	30-Oct-20	21	1,288	30-Oct-20	0	-
93	BANK OF AMERICA	16-Oct-20	100	80	EFT	16-Sep-20	12-Oct-20	29-Sep-20	30-Oct-20	31	2,482	30-Oct-20	0	-
94	BANK OF AMERICA	16-Oct-20	2,375	47	EFT	24-Jun-20	12-Oct-20	18-Aug-20	30-Oct-20	73	3,405	30-Oct-20	0	-
95	BANK OF AMERICA	16-Oct-20	45	28	EFT	24-Sep-20	5-Oct-20	29-Sep-20	30-Oct-20	31	865	30-Oct-20	0	-
96	BANK OF AMERICA	16-Oct-20	614	428	EFT	21-Sep-20	5-Oct-22	28-Sep-21	30-Oct-20	(333)	(142,404)	30-Oct-20	0	-
97	BANK OF AMERICA	16-Nov-20	150	150	EFT	2-Nov-20	2-Nov-20	2-Nov-20	30-Nov-20	28	4,200	30-Nov-20	0	-
98	BANK OF AMERICA	16-Nov-20	996	996	EFT	28-Oct-20	11-Nov-20	4-Nov-20	30-Nov-20	26	25,906	30-Nov-20	0	-
99	BANK OF AMERICA	16-Nov-20	554	482	EFT	20-Oct-20	3-Nov-20	27-Oct-20	30-Nov-20	34	16,388	30-Nov-20	0	-
100	BANK OF AMERICA	16-Nov-20	946	946	EFT	21-Oct-20	30-Oct-20	25-Oct-20	30-Nov-20	36	34,058	30-Nov-20	0	-
101	BANK OF AMERICA	16-Dec-20	168	85	EFT	23-Nov-20	8-Dec-20	30-Nov-20	31-Dec-20	31	2,628	31-Dec-20	0	-
102	BANK OF AMERICA	16-Dec-20	833	427	EFT	17-Nov-20	10-Dec-20	28-Nov-20	31-Dec-20	33	14,096	31-Dec-20	0	-
103	BANK OF AMERICA	16-Dec-20	226	23	EFT	18-Nov-20	15-Dec-20	1-Dec-20	31-Dec-20	30	699	31-Dec-20	0	-
104	BANK OF AMERICA	16-Dec-20	55	55	EFT	17-Nov-20	17-Nov-20	17-Nov-20	31-Dec-20	44	2,424	31-Dec-20	0	-
105	BANK OF AMERICA	16-Dec-20	345	262	EFT	18-Nov-20	30-Nov-20	24-Nov-20	31-Dec-20	37	9,694	31-Dec-20	0	-
106	BANK OF AMERICA	16-Dec-20	245	245	EFT	7-Dec-20	7-Dec-20	7-Dec-20	31-Dec-20	24	5,874	31-Dec-20	0	-
107	BANK OF AMERICA	16-Jan-21	26	26	EFT	4-Jan-21	4-Jan-21	4-Jan-21	29-Jan-21	25	661	29-Jan-21	0	-

Atmos Energy Corporation-Kentucky
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Line No.	Vendor	Invoice Date	Invoice Amount	Division 009 Amount	Payment Type	Service Period From	Service Period To	Midpoint Service Service	Date Paid	Payment lag	Weighted Payment Lag	Date Cleared	Clearing Lag	Weighted Clearing Lag
108	BANK OF AMERICA	16-Jan-21	934	360	EFT	9-Oct-20	29-Jan-21	4-Dec-20	29-Jan-21	56	20,152	29-Jan-21	0	-
109	BANK OF AMERICA	16-Jan-21	77	77	EFT	22-Dec-20	22-Dec-20	22-Dec-20	29-Jan-21	38	2,940	29-Jan-21	0	-
110	BANK OF AMERICA	16-Jan-21	925	571	EFT	8-Dec-20	12-Jan-21	25-Dec-20	29-Jan-21	35	20,002	29-Jan-21	0	-
111	BANK OF AMERICA	16-Feb-21	713	713	EFT	2-Dec-20	22-Feb-21	12-Jan-21	26-Feb-21	45	32,066	26-Feb-21	0	-
112	BANK OF AMERICA	16-Feb-21	351	351	EFT	28-Jan-21	10-Feb-21	3-Feb-21	26-Feb-21	23	8,067	26-Feb-21	0	-
113	BANK OF AMERICA	16-Feb-21	288	288	EFT	2-Feb-21	9-Feb-21	5-Feb-21	26-Feb-21	21	6,038	26-Feb-21	0	-
114	BANK OF AMERICA	16-Mar-21	85	85	EFT	16-Feb-21	18-Feb-21	17-Feb-21	31-Mar-21	42	3,583	31-Mar-21	0	-
115	BANK OF AMERICA	16-Mar-21	192	192	EFT	26-Feb-21	9-Mar-21	3-Mar-21	31-Mar-21	28	5,372	31-Mar-21	0	-
116	BANK OF AMERICA	16-Mar-21	21	21	EFT	18-Feb-21	18-Feb-21	18-Feb-21	31-Mar-21	41	868	31-Mar-21	0	-
117	BANK OF AMERICA	16-Mar-21	329	117	EFT	9-Oct-20	26-Mar-21	1-Jan-21	31-Mar-21	89	10,381	31-Mar-21	0	-
118	Basham, Jake W (Jake)	1-Mar-21	157	157	Direct Deposit	9-Dec-20	4-Feb-21	6-Jan-21	3-Mar-21	56	8,803	3-Mar-21	0	-
119	Baumgardner, Steven M (Steven)	10-Aug-20	25	25	Direct Deposit	22-Jul-20	29-Jul-20	25-Jul-20	11-Aug-20	17	426	11-Aug-20	0	-
120	Baumgardner, Steven M (Steven)	18-Feb-21	63	63	Direct Deposit	16-Nov-20	5-Feb-21	26-Dec-20	22-Feb-21	58	3,657	22-Feb-21	0	-
121	BLUE GRASS ENERGY	7-Jun-20	50	50	CHECK	1-May-20	1-Jun-20	16-May-20	17-Jun-20	32	1,591	26-Jun-20	9	447
122	Bohlen, Silas A (Silas)	8-Oct-20	126	126	Direct Deposit	7-Oct-20	27-Oct-20	17-Oct-20	30-Oct-20	13	1,641	30-Oct-20	0	-
123	Bohlen, Silas A (Silas)	11-Dec-20	984	984	Direct Deposit	9-Dec-20	23-Feb-21	16-Jan-21	27-Jan-21	11	10,821	27-Jan-21	0	-
124	BOWLING GREEN MUNICIPAL UTILITIES	7-Jul-20	1,881	1,881	CHECK	5-Jun-20	7-Jul-20	21-Jun-20	27-Jul-20	36	67,714	6-Aug-20	10	18,809
125	BOWLING GREEN MUNICIPAL UTILITIES	5-Aug-20	193	193	CHECK	7-Jul-20	5-Aug-20	21-Jul-20	31-Aug-20	41	7,907	11-Sep-20	11	2,121
126	BOWLING GREEN MUNICIPAL UTILITIES	9-Nov-20	27	27	CHECK	9-Oct-20	9-Nov-20	24-Oct-20	2-Dec-20	39	1,058	10-Dec-20	8	217
127	Brown, Bobby S (Bobby)	12-Mar-21	497	407	Direct Deposit	4-Mar-21	10-Mar-21	7-Mar-21	17-Mar-21	10	4,065	17-Mar-21	0	-
128	Brown, Sean R (Sean)	23-Jul-20	43	43	Direct Deposit	21-Jul-20	21-Jul-20	21-Jul-20	27-Jul-20	6	261	27-Jul-20	0	-
129	BRYANT CONSULTANTS INC	29-Feb-20	1,600	1,600	CHECK	29-Feb-20	29-Feb-20	29-Feb-20	1-Apr-20	32	51,200	8-Apr-20	7	11,200
130	BUCKMAN CHRIS	30-Aug-20	150	150	CHECK	30-Aug-20	30-Aug-20	30-Aug-20	12-Oct-20	43	6,450	19-Oct-20	7	1,050
131	CAMPBELLSVILLE WATER AND SEWER	11-Jun-20	21	23	CHECK	15-May-20	11-Jun-20	28-May-20	13-Jul-20	46	1,041	22-Jul-20	9	204
132	CAMPBELLSVILLE WATER AND SEWER	19-Aug-20	22	23	CHECK	20-Jul-20	19-Aug-20	4-Aug-20	14-Sep-20	41	955	23-Sep-20	9	210
133	CARDINAL TRACKING INC	20-May-20	986	1,045	Direct Deposit	2-May-20	2-May-20	2-May-20	15-Jun-20	44	45,976	15-Jun-20	0	-
134	CHAMBER OF COMMERCE	1-Jan-21	400	400	CHECK	1-Jan-21	31-Dec-21	2-Jul-21	4-Jan-21	(179)	(71,600)	28-Jan-21	24	9,600
135	CITY OF DANVILLE KY	1-Jun-20	7	7	CHECK	1-May-20	30-Jun-20	31-May-20	6-Jul-20	36	256	15-Jul-20	9	64
136	CITY OF FRANKLIN KY	23-Jul-20	52	52	CHECK	9-Jun-20	9-Jul-20	24-Jun-20	3-Aug-20	40	2,094	17-Aug-20	14	733
137	CITY OF FRANKLIN KY	24-Aug-20	52	52	CHECK	9-Jul-20	10-Aug-20	25-Jul-20	9-Sep-20	46	2,409	21-Sep-20	12	628
138	CLARK BEVERAGE GROUP INC	7-Apr-20	45	45	CHECK	7-Apr-20	7-Apr-20	7-Apr-20	13-Apr-20	6	267	21-Apr-20	8	356
139	CLARK BEVERAGE GROUP INC	14-May-20	111	111	CHECK	14-May-20	14-May-20	14-May-20	20-May-20	6	668	28-May-20	8	890
140	CLEAN GREEN PORTA POTTIES LLC	9-Aug-20	58	62	CHECK	6-Jul-20	2-Aug-20	19-Jul-20	9-Sep-20	52	3,214	21-Sep-20	12	742
141	Coleman, Michael D (Mike)	19-Nov-20	260	260	Direct Deposit	25-Sep-20	17-Nov-20	21-Oct-20	23-Nov-20	33	8,574	23-Nov-20	0	-
142	COMCAST CABLE	8-Jul-20	157	157	CHECK	8-Jun-20	8-Jul-20	23-Jun-20	20-Jul-20	27	4,251	4-Aug-20	15	2,362
143	COMCAST CABLE	8-Oct-20	164	164	CHECK	8-Sep-20	8-Oct-20	23-Sep-20	19-Oct-20	26	4,253	5-Nov-20	17	2,781
144	COMCAST CABLE	8-Nov-20	154	154	Direct Deposit	8-Oct-20	8-Nov-20	23-Oct-20	13-Nov-20	21	3,225	13-Nov-20	0	-
145	COMCAST CABLE	22-Nov-20	325	325	CHECK	22-Oct-20	22-Nov-20	6-Nov-20	2-Dec-20	26	8,446	14-Dec-20	12	3,898
146	COMCAST CABLE	8-Feb-21	177	177	Direct Deposit	8-Jan-21	8-Feb-21	23-Jan-21	11-Feb-21	19	3,358	11-Feb-21	0	-
147	Cox, Matthew T (Matthew)	21-Jul-20	34	34	Direct Deposit	21-Jul-20	21-Jul-20	21-Jul-20	23-Jul-20	2	68	23-Jul-20	0	-
148	Cox, Matthew T (Matthew)	31-Aug-20	40	40	Direct Deposit	25-Aug-20	25-Aug-20	25-Aug-20	3-Sep-20	9	361	3-Sep-20	0	-
149	DAILY NEWS INC	1-Jan-21	208	208	CHECK	7-Jan-21	6-Feb-22	23-Jul-21	11-Jan-21	(194)	(40,428)	21-Jan-21	10	2,084
150	DITCH WITCH MID STATES	20-May-20	306	306	CHECK	20-May-20	20-May-20	20-May-20	4-Jun-20	15	4,594	9-Jun-20	5	1,531
151	DS GARAGE DOOR SERVICE LLC	8-Jan-21	159	159	Direct Deposit	8-Jan-21	8-Jan-21	8-Jan-21	26-Jan-21	18	2,862	26-Jan-21	0	-
152	EGW UTILITIES INC	7-Apr-20	245	245	Direct Deposit	7-Apr-20	7-Apr-20	7-Apr-20	4-May-20	27	6,611	4-May-20	0	-
153	EGW UTILITIES INC	1-May-20	488	488	Direct Deposit	1-May-20	1-May-20	1-May-20	26-May-20	25	12,212	26-May-20	0	-
154	EGW UTILITIES INC	11-Jan-21	943	943	Direct Deposit	11-Jan-21	11-Jan-21	11-Jan-21	5-Feb-21	25	23,571	5-Feb-21	0	-
155	ELEMENT FLEET	6-Apr-20	1,100,412	21,000	Direct Deposit	1-Mar-20	31-Mar-20	16-Mar-20	7-Apr-20	22	461,998	7-Apr-20	0	-
156	ELIZABETHTON ELECTRIC SYSTEM	21-Jan-21	170	170	CHECK	22-Dec-20	21-Jan-21	6-Jan-21	27-Jan-21	21	3,573	3-Feb-21	7	1,191
157	ENGLISH LUCAS PRIEST AND OWSLEY	6-Nov-20	126	126	Direct Deposit	23-Oct-20	23-Oct-20	23-Oct-20	30-Nov-20	38	4,788	30-Nov-20	0	-
158	ENGLISH LUCAS PRIEST AND OWSLEY	4-Dec-20	63	63	Direct Deposit	10-Nov-20	30-Nov-20	20-Nov-20	29-Dec-20	39	2,457	29-Dec-20	0	-
159	ENGLISH LUCAS PRIEST AND OWSLEY	9-Dec-20	1,890	1,890	Direct Deposit	18-Nov-20	30-Nov-20	24-Nov-20	29-Dec-20	35	66,150	29-Dec-20	0	-
160	EWAN NORMA	22-Jan-21	46	46	CHECK	22-Feb-21	22-Feb-22	24-Aug-21	27-Jan-21	(209)	(9,614)	9-Mar-21	41	1,886
161	FARMERS RURAL ELECTRIC COOPERATIVE	17-Sep-20	29	29	CHECK	18-Aug-20	16-Sep-20	1-Sep-20	28-Sep-20	27	778	8-Oct-20	10	288

Atmos Energy Corporation-Kentucky
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Line No.	Vendor	Invoice Date	Invoice Amount	Division 009 Amount	Payment Type	Service Period From	Service Period To	Midpoint Service Service	Date Paid	Payment lag	Weighted Payment Lag	Date Cleared	Clearing Lag	Weighted Clearing Lag
162	FARMERS RURAL ELECTRIC COOPERATIVE	18-Feb-21	29	29	CHECK	18-Jan-21	17-Feb-21	2-Feb-21	1-Mar-21	27	794	10-Mar-21	9	265
163	FIRST-LINE FIRE EXTINGUISHER CO	18-Jun-20	650	650	CHECK	18-Jun-20	18-Jun-20	18-Jun-20	13-Jul-20	25	16,247	22-Jul-20	9	5,849
164	FIRST-LINE FIRE EXTINGUISHER CO	18-Aug-20	971	971	CHECK	18-Aug-20	18-Aug-20	18-Aug-20	14-Sep-20	27	26,225	22-Sep-20	8	7,770
165	FIRST-LINE FIRE EXTINGUISHER CO	29-Oct-20	251	251	CHECK	29-Oct-20	29-Oct-20	29-Oct-20	23-Nov-20	25	6,280	1-Dec-20	8	2,010
166	FRANCOTYP POSTALIA INC	15-May-20	143	143	CHECK	14-May-20	13-Aug-20	28-Jun-20	10-Jun-20	(19)	(2,719)	22-Jun-20	12	1,717
167	FRANKLIN ELECTRIC PLANT BOARD	26-May-20	50	50	CHECK	26-Apr-20	26-May-20	11-May-20	15-Jun-20	35	1,762	23-Jun-20	8	403
168	FRANKLIN ELECTRIC PLANT BOARD	18-Jul-20	32	32	CHECK	16-Jun-20	18-Jul-20	2-Jul-20	3-Aug-20	32	1,031	12-Aug-20	9	290
169	FRANKLIN ELECTRIC PLANT BOARD	28-Oct-20	48	48	CHECK	28-Sep-20	28-Oct-20	13-Oct-20	16-Nov-20	34	1,634	25-Nov-20	9	433
170	GAS AND SUPPLY	13-Jul-20	81	81	CHECK	13-Jul-20	13-Jul-20	13-Jul-20	10-Aug-20	28	2,262	19-Aug-20	9	727
171	GEORG FISCHER CENTRAL PLASTICS	10-Jun-20	1,100	1,166	Direct Deposit	10-Jun-20	10-Jun-20	10-Jun-20	6-Jul-20	26	30,323	6-Jul-20	0	-
172	GEORG FISCHER CENTRAL PLASTICS	9-Feb-21	467	495	Direct Deposit	9-Feb-21	9-Feb-21	9-Feb-21	8-Mar-21	27	13,366	8-Mar-21	0	-
173	GLASGOW ELECTRIC PLANT BOARD	1-Mar-21	80	80	CHECK	1-Feb-21	1-Mar-21	15-Feb-21	15-Mar-21	28	2,249	22-Mar-21	7	562
174	HAWKEYE HELICOPTER LLC	12-Jan-21	1,444	1,444	Direct Deposit	7-Jan-21	7-Jan-21	7-Jan-21	22-Jan-21	15	21,665	22-Jan-21	0	-
175	HOPKINSVILLE ELECTRIC SYSTEM	13-Jun-20	41	29	CHECK	11-May-20	30-Jun-20	5-Jun-20	29-Jun-20	24	693	9-Jul-20	10	289
176	HOPKINSVILLE ELECTRIC SYSTEM	1-Jul-20	192	203	CHECK	1-Jun-20	30-Jun-20	15-Jun-20	27-Jul-20	42	8,537	5-Aug-20	9	1,829
177	HOPKINSVILLE ELECTRIC SYSTEM	8-Nov-20	37	37	CHECK	8-Oct-20	8-Nov-20	23-Oct-20	25-Nov-20	33	1,225	4-Dec-20	9	334
178	HOPKINSVILLE ELECTRIC SYSTEM	20-Jan-21	127	127	CHECK	20-Dec-20	20-Jan-21	4-Jan-21	8-Feb-21	35	4,439	22-Feb-21	14	1,775
179	INTER COUNTY ENERGY	4-May-20	22	22	CHECK	15-Mar-20	15-Apr-20	30-Mar-20	13-May-20	44	946	22-May-20	9	194
180	INTER COUNTY ENERGY	10-May-20	26	26	CHECK	10-Apr-20	10-May-20	25-Apr-20	15-Jun-20	51	1,323	24-Jun-20	9	233
181	INTER COUNTY ENERGY	1-Sep-20	21	21	CHECK	1-Aug-20	1-Sep-20	16-Aug-20	5-Oct-20	50	1,045	14-Oct-20	9	188
182	INTER COUNTY ENERGY	4-Jan-21	23	23	CHECK	15-Nov-20	15-Dec-20	30-Nov-20	18-Jan-21	49	1,130	26-Jan-21	8	185
183	JACKSON PURCHASE ENERGY CORPC	20-Mar-20	25	25	CHECK	21-Feb-20	20-Mar-20	6-Mar-20	8-Apr-20	33	813	15-Apr-20	7	173
184	JACKSON PURCHASE ENERGY CORPC	31-Mar-20	27	29	CHECK	21-Feb-20	20-Mar-20	6-Mar-20	6-Apr-20	31	900	15-Apr-20	9	261
185	JACKSON PURCHASE ENERGY CORPC	15-Apr-20	28	28	CHECK	6-Mar-20	5-Apr-20	21-Mar-20	20-Apr-20	30	840	29-Apr-20	9	252
186	JACKSON PURCHASE ENERGY CORPC	23-Jul-20	12	13	CHECK	14-Jun-20	14-Jul-20	29-Jun-20	27-Jul-20	28	368	5-Aug-20	9	118
187	JACKSON PURCHASE ENERGY CORPC	15-Sep-20	29	31	CHECK	7-Aug-20	6-Sep-20	22-Aug-20	21-Sep-20	30	936	1-Oct-20	10	312
188	JACKSON PURCHASE ENERGY CORPC	22-Jan-21	12	12	CHECK	14-Dec-20	14-Jan-21	29-Dec-20	1-Feb-21	34	418	10-Feb-21	9	111
189	JACKSON PURCHASE ENERGY CORPC	29-Jan-21	30	32	CHECK	21-Dec-20	21-Jan-21	5-Jan-21	3-Feb-21	29	925	10-Feb-21	7	223
190	JACKSON PURCHASE ENERGY CORPC	29-Jan-21	25	27	CHECK	21-Dec-20	21-Jan-21	5-Jan-21	3-Feb-21	29	769	10-Feb-21	7	186
191	JENKINS PLUMBING INC	26-Feb-21	548	548	CHECK	23-Feb-21	23-Feb-21	23-Feb-21	24-Mar-21	29	15,892	2-Apr-21	9	4,932
192	JENNINGS AND LITTLE EXCAVATING	27-Jul-20	979	979	CHECK	27-Jul-20	27-Jul-20	27-Jul-20	24-Aug-20	28	27,409	2-Sep-20	9	8,810
193	JENNINGS AND LITTLE EXCAVATING	27-Jul-20	7,216	7,216	CHECK	27-Jul-20	27-Jul-20	27-Jul-20	24-Aug-20	28	202,038	2-Sep-20	9	64,941
194	JENNINGS AND LITTLE EXCAVATING	10-Aug-20	2,918	2,918	CHECK	10-Aug-20	10-Aug-20	10-Aug-20	9-Sep-20	30	87,539	22-Sep-20	13	37,933
195	JENNINGS AND LITTLE EXCAVATING	26-Aug-20	100	100	CHECK	26-Aug-20	26-Aug-20	26-Aug-20	21-Sep-20	26	2,600	29-Sep-20	8	800
196	JENNINGS AND LITTLE EXCAVATING	26-Oct-20	1,866	1,866	CHECK	26-Oct-20	26-Oct-20	26-Oct-20	23-Nov-20	28	52,237	2-Dec-20	9	16,790
197	JENNINGS AND LITTLE EXCAVATING	22-Jan-21	1,000	1,000	CHECK	22-Jan-21	22-Jan-21	22-Jan-21	19-Feb-21	28	28,000	25-Feb-21	6	6,000
198	JEWELL LAWN AND LANDSCAPE	1-Dec-20	848	848	CHECK	1-Dec-20	1-Dec-20	1-Dec-20	14-Dec-20	13	11,024	23-Dec-20	9	7,632
199	KELLYS KLEENING	25-Feb-21	636	636	Direct Deposit	1-Feb-21	28-Feb-21	14-Feb-21	22-Mar-21	36	22,896	22-Mar-21	0	-
200	KENERGY CORP	6-Apr-20	82	82	CHECK	6-Mar-20	6-Apr-20	21-Mar-20	20-Apr-20	30	2,462	28-Apr-20	8	657
201	KENERGY CORP	2-Jun-20	31	31	CHECK	2-May-20	2-Jun-20	17-May-20	24-Jun-20	38	1,174	1-Jul-20	7	216
202	KENERGY CORP	6-Jun-20	28	28	CHECK	6-May-20	6-Jun-20	21-May-20	22-Jun-20	32	893	30-Jun-20	8	223
203	KENERGY CORP	2-Jul-20	59	59	CHECK	2-Jun-20	2-Jul-20	17-Jun-20	15-Jul-20	28	1,655	27-Jul-20	12	709
204	KENERGY CORP	9-Jul-20	2,028	1,014	CHECK	9-Jun-20	9-Jul-20	24-Jun-20	22-Jul-20	28	28,393	29-Jul-20	7	7,098
205	KENERGY CORP	23-Jul-20	33	33	CHECK	23-Jun-20	23-Jul-20	8-Jul-20	10-Aug-20	33	1,096	18-Aug-20	8	266
206	KENERGY CORP	16-Aug-20	27	27	CHECK	16-Jul-20	16-Aug-20	31-Jul-20	9-Sep-20	40	1,081	17-Sep-20	8	216
207	KENERGY CORP	11-Sep-20	27	27	CHECK	11-Aug-20	11-Sep-20	26-Aug-20	23-Sep-20	28	756	1-Oct-20	8	216
208	KENERGY CORP	16-Sep-20	27	27	CHECK	16-Aug-20	16-Sep-20	31-Aug-20	30-Sep-20	30	810	8-Oct-20	8	216
209	KENERGY CORP	2-Oct-20	64	64	CHECK	2-Sep-20	2-Oct-20	17-Sep-20	19-Oct-20	32	2,053	26-Oct-20	7	449
210	KENERGY CORP	20-Oct-20	38	38	CHECK	20-Sep-20	20-Oct-20	5-Oct-20	4-Nov-20	30	1,141	10-Nov-20	6	228
211	KENERGY CORP	28-Oct-20	27	27	CHECK	28-Sep-20	28-Oct-20	13-Oct-20	16-Nov-20	34	914	23-Nov-20	7	188
212	KENERGY CORP	2-Nov-20	44	44	CHECK	2-Oct-20	2-Nov-20	17-Oct-20	23-Nov-20	37	1,640	3-Dec-20	10	443
213	KENERGY CORP	6-Nov-20	25	25	CHECK	6-Oct-20	6-Nov-20	21-Oct-20	23-Nov-20	33	834	3-Dec-20	10	253
214	KENERGY CORP	17-Dec-20	31	31	CHECK	17-Nov-20	17-Dec-20	2-Dec-20	4-Jan-21	33	1,013	11-Jan-21	7	215
215	KENERGY CORP	20-Feb-21	37	37	CHECK	20-Jan-21	20-Feb-21	4-Feb-21	10-Mar-21	34	1,273	16-Mar-21	6	225

Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For the CWC Study Test Year Ended March 31, 2021

Line No.	Vendor	Invoice Date	Invoice Amount	Division 009 Amount	Payment Type	Service Period From	Service Period To	Midpoint Service Date	Payment Date	Payment lag	Weighted Payment Lag	Date Cleared	Clearing Lag	Weighted Clearing Lag
216	KENERGY CORP	24-Feb-21	25	25	CHECK	6-Jan-21	6-Feb-21	21-Jan-21	1-Mar-21	39	984	8-Mar-21	7	177
217	KENERGY CORP	2-Mar-21	42	42	CHECK	2-Feb-21	2-Mar-21	16-Feb-21	22-Mar-21	34	1,419	29-Mar-21	7	292
218	KENERGY CORP	6-Mar-21	39	39	CHECK	6-Feb-21	6-Mar-21	20-Feb-21	24-Mar-21	32	1,248	31-Mar-21	7	273
219	KENERGY CORP	6-Mar-21	47	47	CHECK	6-Feb-21	6-Mar-21	20-Feb-21	24-Mar-21	32	1,511	31-Mar-21	7	331
220	KENTUCKY 811	8-Jan-21	8,652	8,652	Direct Deposit	1-Dec-20	31-Dec-20	16-Dec-20	2-Feb-21	48	415,296	2-Feb-21	0	-
221	KENTUCKY COUNTY JUDGE EXECUTIV	6-Jan-21	200	200	CHECK	1-Jan-21	31-Dec-21	2-Jul-21	15-Mar-21	(109)	(21,800)	26-Mar-21	11	2,200
222	KU ENERGY CORPORATION	20-Apr-20	38	38	CHECK	18-Mar-20	17-Apr-20	2-Apr-20	29-Apr-20	27	1,031	11-May-20	12	458
223	KU ENERGY CORPORATION	12-May-20	36	36	CHECK	13-Apr-20	11-May-20	27-Apr-20	27-May-20	30	1,072	8-Jun-20	12	429
224	KU ENERGY CORPORATION	18-May-20	37	37	CHECK	16-Apr-20	15-May-20	30-Apr-20	27-May-20	27	996	8-Jun-20	12	443
225	KU ENERGY CORPORATION	23-Jun-20	12	12	CHECK	22-May-20	22-Jun-20	6-Jun-20	1-Jul-20	25	308	13-Jul-20	12	148
226	KU ENERGY CORPORATION	24-Jun-20	54	54	CHECK	23-May-20	24-Jun-20	8-Jun-20	13-Jul-20	35	1,873	28-Jul-20	15	803
227	KU ENERGY CORPORATION	20-Aug-20	5	5	CHECK	18-Jul-20	20-Aug-20	3-Aug-20	9-Sep-20	37	188	23-Sep-20	14	71
228	KU ENERGY CORPORATION	21-Aug-20	12	12	CHECK	23-Jul-20	20-Aug-20	6-Aug-20	9-Sep-20	34	416	23-Sep-20	14	171
229	KU ENERGY CORPORATION	17-Sep-20	12	12	CHECK	18-Aug-20	16-Sep-20	1-Sep-20	28-Sep-20	27	318	14-Oct-20	16	189
230	KU ENERGY CORPORATION	21-Sep-20	43	43	CHECK	19-Aug-20	18-Sep-20	3-Sep-20	30-Sep-20	27	1,162	8-Oct-20	8	344
231	KU ENERGY CORPORATION	8-Oct-20	38	38	CHECK	4-Sep-20	7-Oct-20	20-Sep-20	21-Oct-20	31	1,175	27-Oct-20	6	227
232	KU ENERGY CORPORATION	5-Nov-20	37	37	CHECK	6-Oct-20	4-Nov-20	20-Oct-20	18-Nov-20	29	1,074	27-Nov-20	9	333
233	KU ENERGY CORPORATION	22-Dec-20	12	12	CHECK	20-Nov-20	21-Dec-20	5-Dec-20	4-Jan-21	30	374	15-Jan-21	11	137
234	KU ENERGY CORPORATION	17-Feb-21	42	42	CHECK	15-Jan-21	16-Feb-21	31-Jan-21	1-Mar-21	29	1,229	9-Mar-21	8	339
235	KU ENERGY CORPORATION	19-Mar-21	12	12	CHECK	18-Feb-21	18-Mar-21	4-Mar-21	31-Mar-21	27	319	6-Apr-21	6	71
236	LASER BEAM STUDIO LLP	17-Apr-20	971	971	Direct Deposit	17-Apr-20	17-Apr-20	17-Apr-20	12-May-20	25	24,274	12-May-20	0	-
237	LAWN WORX LLC	31-Aug-20	3,540	3,540	CHECK	1-Aug-20	31-Aug-20	16-Aug-20	28-Sep-20	43	152,237	7-Oct-20	9	31,864
238	LEBANON WATER WORKS INC	15-Sep-20	24	24	CHECK	14-Aug-20	15-Sep-20	30-Aug-20	14-Oct-20	45	1,059	21-Oct-20	7	165
239	LOGANS INC	16-Nov-20	44	44	Direct Deposit	16-Nov-20	16-Nov-20	16-Nov-20	11-Dec-20	25	1,104	11-Dec-20	0	-
240	Lowe, Brett P (Brett)	30-Sep-20	784	714	Direct Deposit	9-Jul-20	30-Sep-20	19-Aug-20	2-Oct-20	44	31,412	2-Oct-20	0	-
241	MADISONVILLE MUNICIPAL UTILITIES	4-May-20	34	34	CHECK	5-Apr-20	4-May-20	19-Apr-20	20-May-20	31	1,054	1-Jun-20	12	408
242	MADISONVILLE MUNICIPAL UTILITIES	17-Aug-20	84	84	CHECK	20-Jul-20	17-Aug-20	3-Aug-20	9-Sep-20	37	3,090	22-Sep-20	13	1,086
243	MADISONVILLE MUNICIPAL UTILITIES	3-Feb-21	38	38	CHECK	12-Dec-20	21-Jan-21	1-Jan-21	3-Feb-21	33	1,264	11-Feb-21	8	306
244	MADISONVILLE MUNICIPAL UTILITIES	1-Mar-21	1,229	738	CHECK	3-Feb-21	1-Mar-21	16-Feb-21	22-Mar-21	34	25,076	30-Mar-21	8	5,900
245	MARTIN MARIETTA MATERIALS	3-Sep-20	580	580	CHECK	9-Sep-20	9-Sep-20	9-Sep-20	28-Oct-20	49	28,419	2-Nov-20	5	2,900
246	MASTERCRAFT PRINTED PRODUCTS A	15-Jul-20	190	201	Direct Deposit	14-Jul-20	14-Jul-20	14-Jul-20	10-Aug-20	27	5,425	10-Aug-20	0	-
247	Mattingly, Patrick T (Pat)	12-Aug-20	168	123	Direct Deposit	1-Jul-20	5-Aug-20	18-Jul-20	13-Aug-20	26	3,193	13-Aug-20	0	-
248	Mattingly, Patrick T (Pat)	8-Oct-20	73	66	Direct Deposit	1-Oct-20	7-Oct-20	4-Oct-20	13-Oct-20	9	593	13-Oct-20	0	-
249	Mayes, Larry A (Andy)	15-Dec-20	104	104	Direct Deposit	11-Dec-20	10-Jan-21	26-Dec-20	17-Dec-20	(9)	(934)	17-Dec-20	0	-
250	MCGRUFF SEIBELS AND WILLIAMS INC	1-Sep-20	102	102	CHECK	22-Sep-20	22-Sep-21	23-Mar-21	14-Sep-20	(191)	(19,444)	23-Sep-20	9	916
251	MCGRUFF SEIBELS AND WILLIAMS INC	2-Feb-21	800	800	CHECK	15-Feb-21	15-Feb-22	16-Aug-21	19-Feb-21	(179)	(143,200)	26-Feb-21	7	5,600
252	MCGRUFF SEIBELS AND WILLIAMS INC	2-Mar-21	102	102	CHECK	1-Mar-21	1-Mar-22	30-Aug-21	8-Mar-21	(176)	(17,917)	16-Mar-21	8	814
253	MEADE COUNTY RURAL ELECTRIC	8-Jul-20	138	138	CHECK	3-Jun-20	3-Jul-20	18-Jun-20	15-Jul-20	27	3,721	28-Jul-20	13	1,792
254	MERIWETHER RANDY	2-Jun-20	800	800	CHECK	1-Jun-20	30-Jun-20	15-Jun-20	29-Jun-20	14	11,200	13-Jul-20	14	11,200
255	MERIWETHER RANDY	1-Aug-20	800	800	CHECK	1-Aug-20	31-Aug-20	16-Aug-20	26-Aug-20	10	8,000	2-Sep-20	7	5,600
256	MERIWETHER RANDY	1-Dec-20	800	800	CHECK	1-Dec-20	31-Dec-20	16-Dec-20	29-Dec-20	13	10,400	7-Jan-21	9	7,200
257	MGA SPECIAL EVENTS	1-Sep-20	1,000	1,060	CHECK	5-Oct-20	10-Oct-20	7-Oct-20	16-Sep-20	(22)	(23,320)	1-Oct-20	15	15,900
258	MODERN SUPPLY COMPANY INC	31-Dec-20	70	75	CHECK	1-Dec-20	31-Dec-20	16-Dec-20	11-Jan-21	26	1,940	20-Jan-21	9	672
259	MRC GLOBAL	26-May-20	226,792	4,222	Direct Deposit	24-Mar-20	26-May-20	24-Apr-20	15-Jun-20	52	219,520	15-Jun-20	0	-
260	MRC GLOBAL	26-Oct-20	369,999	3,905	Direct Deposit	3-Aug-20	26-Oct-20	14-Sep-20	16-Nov-20	63	245,984	16-Nov-20	0	-
261	MRC GLOBAL	4-Jan-21	198,202	1,540	Direct Deposit	10-Nov-20	4-Jan-21	7-Dec-20	25-Jan-21	49	75,470	25-Jan-21	0	-
262	MRC GLOBAL	15-Feb-21	175,947	2,863	Direct Deposit	19-Jan-21	15-Feb-21	1-Feb-21	8-Mar-21	35	100,204	8-Mar-21	0	-
263	Nash, Kenneth W (Kenny)	18-Nov-20	253	253	Direct Deposit	3-Nov-20	9-Jan-20	6-Jun-20	20-Nov-20	167	42,181	20-Nov-20	0	-
264	ONE HEALTH	3-Aug-19	75	75	CHECK	23-Aug-19	23-Aug-19	23-Aug-19	17-Jun-20	299	22,425	3-Jul-20	16	1,200
265	ONE HEALTH	31-Jan-21	75	75	CHECK	5-Jan-21	5-Jan-21	5-Jan-21	19-Feb-21	45	3,375	26-Feb-21	7	525
266	OPC PEST SERVICES	18-Dec-20	55	55	CHECK	18-Dec-20	18-Dec-20	18-Dec-20	29-Dec-20	11	605	6-Jan-21	8	440
267	ORKIN PEST CONTROL	12-Oct-20	226	226	CHECK	12-Oct-20	12-Oct-20	12-Oct-20	14-Dec-20	63	14,216	22-Dec-20	8	1,805
268	OWENS CONSTRUCTION	30-Mar-20	2,200	2,200	CHECK	30-Mar-20	30-Mar-20	30-Mar-20	27-Apr-20	28	61,600	14-May-20	17	37,400
269	OWENS CONSTRUCTION	7-Sep-20	2,100	2,100	CHECK	7-Sep-20	7-Sep-20	7-Sep-20	5-Oct-20	28	58,800	22-Oct-20	17	35,700

Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For the CWC Study Test Year Ended March 31, 2021

CWC WP 5-1

Line No.	Vendor	Invoice Date	Invoice Amount	Division 009 Amount	Payment Type	Service Period		Midpoint Service Date	Date Paid	Payment lag	Weighted Payment Lag	Date Cleared	Clearing Lag	Weighted Clearing Lag
						From	To							
270	OWENSBORO MUNICIPAL UTILITIES	17-Apr-20	33	33	CHECK	13-Mar-20	13-Apr-20	28-Mar-20	29-Apr-20	32	1,066	11-May-20	12	400
271	OWENSBORO MUNICIPAL UTILITIES	19-Aug-20	1,036	1,036	CHECK	20-Jul-20	19-Aug-20	4-Aug-20	31-Aug-20	27	27,975	9-Sep-20	9	9,325
272	OWENSBORO MUNICIPAL UTILITIES	18-Sep-20	1,036	1,036	CHECK	19-Aug-20	18-Sep-20	3-Sep-20	5-Oct-20	32	33,155	9-Oct-20	4	4,144
273	OWENSBORO MUNICIPAL UTILITIES	2-Nov-20	38	38	CHECK	29-Sep-20	27-Oct-20	13-Oct-20	16-Nov-20	34	1,297	23-Nov-20	7	267
274	OWENSBORO MUNICIPAL UTILITIES	22-Feb-21	36	36	CHECK	24-Dec-20	26-Jan-21	9-Jan-21	24-Feb-21	46	1,657	2-Mar-21	6	216
275	PADUCAH BOARD OF REALTORS INC	14-Dec-20	300	300	CHECK	1-Jan-21	31-Dec-21	2-Jul-21	4-Jan-21	(179)	(53,700)	13-Jan-21	9	2,700
276	PADUCAH POWER SYSTEM	24-Mar-20	42	42	CHECK	23-Feb-20	23-Mar-20	8-Mar-20	6-Apr-20	29	1,216	14-Apr-20	8	335
277	PADUCAH POWER SYSTEM	27-Mar-20	781	781	CHECK	25-Feb-20	25-Mar-20	10-Mar-20	13-Apr-20	34	26,554	20-Apr-20	7	5,467
278	PADUCAH POWER SYSTEM	14-May-20	39	39	CHECK	14-Apr-20	13-May-20	28-Apr-20	27-May-20	29	1,134	4-Jun-20	8	313
279	PADUCAH POWER SYSTEM	16-Jul-20	39	39	CHECK	11-Jun-20	14-Jul-20	27-Jun-20	29-Jul-20	32	1,247	7-Aug-20	9	351
280	PADUCAH POWER SYSTEM	13-Oct-20	36	36	CHECK	10-Sep-20	11-Oct-20	25-Sep-20	11-Nov-20	47	1,687	18-Nov-20	7	251
281	PADUCAH POWER SYSTEM	3-Nov-20	31	31	CHECK	30-Sep-20	1-Nov-20	16-Oct-20	18-Nov-20	33	1,017	27-Nov-20	9	277
282	PADUCAH POWER SYSTEM	17-Nov-20	24	24	CHECK	14-Oct-20	15-Nov-20	30-Oct-20	16-Dec-20	47	1,129	23-Dec-20	7	168
283	PADUCAH POWER SYSTEM	8-Dec-20	36	36	CHECK	5-Nov-20	6-Dec-20	20-Nov-20	21-Dec-20	31	1,118	29-Dec-20	8	288
284	PADUCAH POWER SYSTEM	27-Jan-21	41	41	CHECK	21-Dec-20	22-Jan-21	6-Jan-21	8-Feb-21	33	1,337	19-Feb-21	11	446
285	PADUCAH POWER SYSTEM	29-Jan-21	691	691	CHECK	25-Dec-20	25-Jan-20	10-Jul-20	12-Feb-21	217	149,958	19-Feb-21	7	4,837
286	PADUCAH POWER SYSTEM	11-Mar-21	28	28	CHECK	11-Feb-21	11-Mar-21	25-Feb-21	29-Mar-21	32	906	2-Apr-21	4	113
287	PADUCAH SUN INC	1-Nov-20	565	565	CHECK	1-Nov-20	1-Nov-20	1-Nov-20	18-Nov-20	17	9,605	24-Nov-20	6	3,390
288	PADUCAH WATER WORKS	25-Sep-20	112	119	CHECK	25-Aug-20	25-Sep-20	9-Sep-20	21-Oct-20	42	4,982	27-Oct-20	6	712
289	Patterson, Joshua T. (Josh)	9-Feb-21	12	12	Direct Deposit	8-Feb-21	8-Feb-21	8-Feb-21	10-Feb-21	2	24	10-Feb-21	0	-
290	Payne, James M (James)	24-Jul-20	390	390	Direct Deposit	8-Jul-20	23-Jul-20	15-Jul-20	29-Jul-20	14	5,466	29-Jul-20	0	-
291	Payne, James M (James)	10-Dec-20	394	394	Direct Deposit	19-Nov-20	9-Dec-20	29-Nov-20	14-Dec-20	15	5,917	14-Dec-20	0	-
292	PENNYRILE RURAL ELECTRIC COOP C	17-May-20	38	38	CHECK	17-Apr-20	17-May-20	2-May-20	27-May-20	25	951	3-Jun-20	7	266
293	PENNYRILE RURAL ELECTRIC COOP C	26-May-20	38	38	CHECK	26-Apr-20	26-May-20	11-May-20	4-Jun-20	24	915	12-Jun-20	8	305
294	PENNYRILE RURAL ELECTRIC COOP C	17-Jun-20	35	35	CHECK	17-May-20	17-Jun-20	1-Jun-20	22-Jun-20	21	727	30-Jun-20	8	277
295	PENNYRILE RURAL ELECTRIC COOP C	23-Jun-20	34	34	CHECK	23-May-20	23-Jun-20	7-Jun-20	29-Jun-20	22	759	7-Jul-20	8	276
296	PENNYRILE RURAL ELECTRIC COOP C	17-Aug-20	35	35	CHECK	17-Jul-20	17-Aug-20	1-Aug-20	24-Aug-20	23	799	1-Sep-20	8	278
297	PENNYRILE RURAL ELECTRIC COOP C	17-Aug-20	70	70	CHECK	17-Jul-20	17-Aug-20	1-Aug-20	24-Aug-20	23	1,608	1-Sep-20	8	559
298	PENNYRILE RURAL ELECTRIC COOP C	21-Oct-20	37	37	CHECK	20-Sep-20	21-Oct-20	5-Oct-20	26-Oct-20	21	768	2-Nov-20	7	256
299	PENNYRILE RURAL ELECTRIC COOP C	17-Nov-20	34	34	CHECK	18-Oct-20	17-Nov-20	2-Nov-20	23-Nov-20	21	722	1-Dec-20	8	275
300	PENNYRILE RURAL ELECTRIC COOP C	26-Nov-20	33	33	CHECK	26-Oct-20	26-Nov-20	10-Nov-20	2-Dec-20	22	724	8-Dec-20	6	197
301	PENNYRILE RURAL ELECTRIC COOP C	17-Dec-20	32	32	CHECK	17-Nov-20	17-Dec-20	2-Dec-20	29-Dec-20	27	873	5-Jan-21	7	226
302	PENNYRILE RURAL ELECTRIC COOP C	29-Dec-20	144	144	CHECK	29-Nov-20	29-Dec-20	14-Dec-20	4-Jan-21	21	3,020	11-Jan-21	7	1,007
303	PENNYRILE RURAL ELECTRIC COOP C	17-Jan-21	28	28	CHECK	17-Dec-20	17-Jan-21	1-Jan-21	25-Jan-21	24	678	1-Feb-21	7	198
304	PENNYRILE RURAL ELECTRIC COOP C	17-Jan-21	13	13	CHECK	17-Dec-20	17-Jan-21	1-Jan-21	25-Jan-21	24	316	1-Feb-21	7	92
305	PENNYRILE RURAL ELECTRIC COOP C	17-Jan-21	65	65	CHECK	17-Dec-20	17-Jan-21	1-Jan-21	25-Jan-21	24	1,548	1-Feb-21	7	452
306	PENNYRILE RURAL ELECTRIC COOP C	20-Jan-21	37	37	CHECK	20-Dec-20	21-Jan-21	5-Jan-21	25-Jan-21	20	730	1-Feb-21	7	256
307	PENNYRILE RURAL ELECTRIC COOP C	17-Mar-21	35	35	CHECK	16-Feb-21	17-Mar-21	2-Mar-21	22-Mar-21	20	696	26-Mar-21	4	139
308	QUALITY SERVICE PLUMBING	20-Apr-20	455	455	CHECK	20-Apr-20	20-Apr-20	20-Apr-20	18-May-20	28	12,740	27-May-20	9	4,095
309	QUINT UTILITIES AND EXCAVATION	30-Jul-20	23,500	23,500	CHECK	30-Jul-20	30-Jul-20	30-Jul-20	17-Aug-20	18	423,000	28-Aug-20	11	258,500
310	QUINT UTILITIES AND EXCAVATION	21-Sep-20	300	300	CHECK	21-Sep-20	21-Sep-20	21-Sep-20	23-Sep-20	2	600	26-Oct-20	33	9,900
311	REPUBLIC SERVICES	20-Jun-20	100	100	Direct Deposit	1-Jul-20	31-Jul-20	16-Jul-20	6-Jul-20	(10)	(996)	6-Jul-20	0	-
312	REPUBLIC SERVICES	20-Jul-20	115	115	Direct Deposit	1-Aug-20	31-Aug-20	16-Aug-20	31-Jul-20	(16)	(1,842)	31-Jul-20	0	-
313	REPUBLIC SERVICES	15-Sep-20	521	521	Direct Deposit	1-Oct-20	31-Oct-20	16-Oct-20	29-Sep-20	(17)	(8,857)	29-Sep-20	0	-
314	REPUBLIC SERVICES	25-Sep-20	1,221	1,221	Direct Deposit	1-Oct-20	31-Oct-20	16-Oct-20	13-Oct-20	(3)	(3,662)	13-Oct-20	0	-
315	REPUBLIC SERVICES	25-Sep-20	920	920	Direct Deposit	1-Oct-20	31-Oct-20	16-Oct-20	9-Oct-20	(7)	(6,439)	9-Oct-20	0	-
316	REPUBLIC SERVICES	25-Nov-20	1,217	1,217	Direct Deposit	1-Dec-20	31-Dec-20	16-Dec-20	17-Dec-20	1	1,217	17-Dec-20	0	-
317	REPUBLIC SERVICES	28-Feb-21	374	374	Direct Deposit	1-Mar-21	31-Mar-21	16-Mar-21	15-Mar-21	(1)	(374)	15-Mar-21	0	-
318	RICOH USA INC	6-Jul-20	3,718	3,718	CHECK	1-May-20	31-Jul-20	15-Jun-20	3-Aug-20	49	182,164	11-Aug-20	8	29,741
319	Sanderson, Jackson (Jackson)	29-May-20	33	33	Direct Deposit	18-May-20	18-May-20	18-May-20	2-Jun-20	15	494	2-Jun-20	0	-
320	Sanderson, Jackson (Jackson)	22-Jul-20	71	71	Direct Deposit	10-Jul-20	21-Jul-20	15-Jul-20	24-Jul-20	9	642	24-Jul-20	0	-
321	SCOTT WASTE SERVICES INC	27-Aug-20	61	61	CHECK	1-Aug-20	31-Aug-20	16-Aug-20	16-Sep-20	31	1,900	29-Sep-20	13	797
322	SELECT SECURITY	27-Apr-20	225	225	CHECK	27-Apr-20	27-Apr-20	27-Apr-20	18-May-20	21	4,725	27-May-20	9	2,025
323	SELECT SECURITY	28-Apr-20	132	132	CHECK	27-Mar-20	27-Mar-20	27-Mar-20	18-May-20	52	6,864	27-May-20	9	1,188

Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For the CWC Study Test Year Ended March 31, 2021

CWC WP 5-1

Line No.	Vendor	Invoice Date	Invoice Amount	Division 009 Amount	Payment Type	Service Period From	Service Period To	Midpoint Service Date	Date Paid	Payment lag	Weighted Payment Lag	Date Cleared	Clearing Lag	Weighted Clearing Lag
324	SENSIT TECHNOLOGIES	30-Oct-20	264	280	CHECK	30-Oct-20	30-Oct-20	30-Oct-20	16-Nov-20	17	4,765	24-Nov-20	8	2,242
325	SENSONICS INC	14-Aug-20	50	50	Direct Deposit	14-Aug-20	14-Aug-20	14-Aug-20	21-Aug-20	7	350	21-Aug-20	0	-
326	SHELBYVILLE MUNICIPAL WATER AND	30-Dec-20	29	29	CHECK	13-Nov-20	14-Dec-20	28-Nov-20	11-Jan-21	44	1,268	19-Jan-21	8	231
327	SHELLY TOLES PLUMBING INC	19-Feb-21	125	125	CHECK	19-Feb-21	19-Feb-21	19-Feb-21	1-Mar-21	10	1,250	5-Mar-21	4	500
328	SITEX CORPORATION	30-Jun-20	1,789	1,789	CHECK	1-Jun-20	30-Jun-20	15-Jun-20	27-Jul-20	42	75,138	4-Aug-20	8	14,312
329	SITEX CORPORATION	31-Dec-20	1,461	1,461	CHECK	7-Dec-20	28-Dec-20	17-Dec-20	25-Jan-21	39	56,984	1-Feb-21	7	10,228
330	Smith, Darrel R (Darrel)	11-Jun-20	46	46	Direct Deposit	11-Jun-20	12-Jun-20	11-Jun-20	2-Jul-20	21	975	2-Jul-20	0	-
331	SOUTH HOPKINS WATER DISTRICT	16-Jun-20	27	27	CHECK	21-May-20	16-Jun-20	3-Jun-20	1-Jul-20	28	759	9-Jul-20	8	217
332	SOUTH HOPKINS WATER DISTRICT	16-Jul-20	13	13	CHECK	16-Jun-20	16-Jul-20	1-Jul-20	12-Aug-20	42	551	20-Aug-20	8	105
333	STYLES BY JOE - JOES CLEANING SER	1-Dec-20	700	700	Direct Deposit	1-Dec-20	1-Dec-20	1-Dec-20	28-Dec-20	27	18,900	28-Dec-20	0	-
334	SUBLETT-BUNTON MYRA	13-Jan-21	848	848	CHECK	13-Jan-21	13-Jan-21	13-Jan-21	3-Feb-21	21	17,808	10-Feb-21	7	5,936
335	SUBMAR INC	29-Jul-20	26,767	26,767	Direct Deposit	30-Jul-20	30-Jul-20	30-Jul-20	24-Aug-20	25	669,178	24-Aug-20	0	-
336	SUPERIOR LAWN CARE	21-Aug-20	159	159	CHECK	21-Aug-20	21-Aug-20	21-Aug-20	31-Aug-20	10	1,590	14-Sep-20	14	2,226
337	TAYLOR COUNTY RURAL ELECTRIC CC	6-Apr-20	18	18	CHECK	29-Feb-20	21-Mar-20	10-Mar-20	29-Apr-20	50	924	7-May-20	8	148
338	TAYLOR COUNTY RURAL ELECTRIC CC	31-Jan-21	31	31	CHECK	31-Dec-20	31-Jan-21	15-Jan-21	24-Feb-21	40	1,231	3-Mar-21	7	215
339	TAYLOR COUNTY RURAL ELECTRIC CC	3-Feb-21	15	15	CHECK	31-Dec-20	31-Jan-21	15-Jan-21	24-Feb-21	40	602	3-Mar-21	7	105
340	TIME WARNER CABLE	24-Sep-20	95	95	CHECK	24-Aug-20	24-Sep-20	8-Sep-20	5-Oct-20	27	2,562	14-Oct-20	9	854
341	TIME WARNER CABLE	3-Oct-20	29,021	1,085	CHECK	3-Sep-20	3-Oct-20	18-Sep-20	12-Oct-20	24	26,051	19-Oct-20	7	7,598
342	Tolbert, Ryan K (Ryan)	23-Apr-20	120	120	Direct Deposit	23-Apr-20	23-Apr-20	23-Apr-20	27-Apr-20	4	480	27-Apr-20	0	-
343	TRAILER AND TRACTOR SERVICE LLC	19-Aug-20	40	42	CHECK	18-Aug-20	18-Aug-20	18-Aug-20	14-Sep-20	27	1,145	22-Sep-20	8	339
344	TRI STATE METER AND REGULATOR S	3-Feb-21	664	664	CHECK	3-Feb-21	3-Feb-21	3-Feb-21	1-Mar-21	26	17,270	8-Mar-21	7	4,650
345	Tullis, Jimmie (Jimmie)	21-May-20	395	395	Direct Deposit	5-May-20	5-May-20	5-May-20	22-May-20	17	6,715	22-May-20	0	-
346	VALOR LLC	7-Dec-20	1,516	1,607	CHECK	7-Dec-20	7-Dec-20	7-Dec-20	22-Mar-21	105	168,764	26-Mar-21	4	6,429
347	VF IMAGEWEAR INC	15-Apr-20	59	59	Direct Deposit	15-Apr-20	15-Apr-20	15-Apr-20	11-May-20	26	1,547	11-May-20	0	-
348	VF IMAGEWEAR INC	1-Jun-20	158	158	Direct Deposit	1-Jun-20	1-Jun-20	1-Jun-20	26-Jun-20	25	3,947	26-Jun-20	0	-
349	VF IMAGEWEAR INC	18-Jun-20	322	322	Direct Deposit	18-Jun-20	18-Jun-20	18-Jun-20	13-Jul-20	25	8,044	13-Jul-20	0	-
350	VF IMAGEWEAR INC	16-Sep-20	300	300	Direct Deposit	16-Sep-20	16-Sep-20	16-Sep-20	13-Oct-20	27	8,099	13-Oct-20	0	-
351	VF IMAGEWEAR INC	7-Oct-20	262	262	Direct Deposit	7-Oct-20	7-Oct-20	7-Oct-20	2-Nov-20	26	6,814	2-Nov-20	0	-
352	VF IMAGEWEAR INC	14-Oct-20	148	148	Direct Deposit	14-Oct-20	14-Oct-20	14-Oct-20	9-Nov-20	26	3,848	9-Nov-20	0	-
353	VF IMAGEWEAR INC	22-Oct-20	129	129	Direct Deposit	22-Oct-20	22-Oct-20	22-Oct-20	16-Nov-20	25	3,231	16-Nov-20	0	-
354	VF IMAGEWEAR INC	26-Oct-20	296	296	Direct Deposit	26-Oct-20	26-Oct-20	26-Oct-20	20-Nov-20	25	7,394	20-Nov-20	0	-
355	VF IMAGEWEAR INC	28-Oct-20	141	141	Direct Deposit	28-Oct-20	28-Oct-20	28-Oct-20	23-Nov-20	26	3,679	23-Nov-20	0	-
356	VF IMAGEWEAR INC	28-Oct-20	238	238	Direct Deposit	28-Oct-20	28-Oct-20	28-Oct-20	23-Nov-20	26	6,189	23-Nov-20	0	-
357	VF IMAGEWEAR INC	10-Nov-20	252	252	Direct Deposit	10-Nov-20	10-Nov-20	10-Nov-20	7-Dec-20	27	6,798	7-Dec-20	0	-
358	VF IMAGEWEAR INC	10-Nov-20	288	288	Direct Deposit	10-Nov-20	10-Nov-20	10-Nov-20	7-Dec-20	27	7,786	7-Dec-20	0	-
359	VF IMAGEWEAR INC	7-Dec-20	145	145	Direct Deposit	7-Dec-20	7-Dec-20	7-Dec-20	4-Jan-21	28	4,047	4-Jan-21	0	-
360	VF IMAGEWEAR INC	18-Dec-20	534	534	Direct Deposit	18-Dec-20	18-Dec-20	18-Dec-20	12-Jan-21	25	13,355	12-Jan-21	0	-
361	VF IMAGEWEAR INC	12-Jan-21	156	156	Direct Deposit	12-Jan-21	12-Jan-21	12-Jan-21	8-Feb-21	27	4,202	8-Feb-21	0	-
362	VF IMAGEWEAR INC	9-Feb-21	438	438	Direct Deposit	9-Feb-21	9-Feb-21	9-Feb-21	8-Mar-21	27	11,829	8-Mar-21	0	-
363	VF IMAGEWEAR INC	22-Feb-21	410	410	Direct Deposit	22-Feb-21	22-Feb-21	22-Feb-21	19-Mar-21	25	10,258	19-Mar-21	0	-
364	VULCAN INC	14-Apr-20	253	253	Direct Deposit	14-Apr-20	14-Apr-20	14-Apr-20	11-May-20	27	6,843	11-May-20	0	-
365	WALDROP JERRY	20-Nov-20	159	159	CHECK	1-Nov-20	30-Nov-20	15-Nov-20	14-Dec-20	29	4,611	24-Dec-20	10	1,590
366	WALKERS TOWING SERVICE	23-Feb-21	425	451	CHECK	23-Feb-21	23-Feb-21	23-Feb-21	22-Mar-21	27	12,164	8-Apr-21	17	7,659
367	WARREN RURAL ELECTRIC COOP	30-Mar-20	25	25	CHECK	22-Feb-20	22-Mar-20	7-Mar-20	13-Apr-20	37	938	21-Apr-20	8	203
368	WARREN RURAL ELECTRIC COOP	23-Apr-20	23	23	CHECK	17-Mar-20	17-Apr-20	1-Apr-20	4-May-20	33	769	11-May-20	7	163
369	WARREN RURAL ELECTRIC COOP	22-May-20	22	22	CHECK	17-Apr-20	17-May-20	2-May-20	1-Jun-20	30	668	9-Jun-20	8	178
370	WARREN RURAL ELECTRIC COOP	9-Jun-20	24	24	CHECK	2-May-20	2-Jun-20	17-May-20	22-Jun-20	36	846	30-Jun-20	8	188
371	WARREN RURAL ELECTRIC COOP	12-Jun-20	23	23	CHECK	7-May-20	7-Jun-20	22-May-20	22-Jun-20	31	708	30-Jun-20	8	183
372	WARREN RURAL ELECTRIC COOP	6-Aug-20	27	27	CHECK	29-Jun-20	29-Jul-20	14-Jul-20	19-Aug-20	36	973	26-Aug-20	7	189
373	WARREN RURAL ELECTRIC COOP	20-Oct-20	49	49	CHECK	12-Sep-20	12-Oct-20	27-Sep-20	2-Nov-20	36	1,760	6-Nov-20	4	196
374	WARREN RURAL ELECTRIC COOP	18-Nov-20	48	48	CHECK	12-Oct-20	12-Nov-20	27-Oct-20	2-Dec-20	36	1,730	8-Dec-20	6	288
375	WEST DAVIESS CO WATER DISTRICT	31-Aug-20	4	4	CHECK	24-Jul-20	24-Aug-20	8-Aug-20	14-Sep-20	37	131	23-Sep-20	9	32
376	WEST KENTUCKY RURAL ELECTRIC	2-May-20	88	88	Direct Deposit	31-Mar-20	2-May-20	16-Apr-20	19-May-20	33	2,913	19-May-20	0	-
377	WEST KENTUCKY RURAL ELECTRIC	7-Aug-20	34	34	Direct Deposit	7-Aug-20	6-Sep-20	22-Aug-20	20-Aug-20	(2)	(68)	20-Aug-20	0	-

Atmos Energy Corporation-Kentucky
Other O&M Payment and Check Clearing Lag
For the CWC Study Test Year Ended March 31, 2021

CWC WP 5-1

Line No.	Vendor	Invoice Date	Invoice Amount	Division 009 Amount	Payment Type	Service Period From	Service Period To	Midpoint Service Service	Date Paid	Payment lag	Weighted Payment Lag	Date Cleared	Clearing Lag	Weighted Clearing Lag
378	WILLIAMS PROFESSIONAL COATINGS	25-Aug-20	10,000	10,000	CHECK	25-Aug-20	25-Aug-20	25-Aug-20	9-Sep-20	15	150,000	21-Sep-20	12	120,000
379	WILSON HUTCHINSON POTEAT & LITTL	1-Feb-21	6,000	6,000	CHECK	16-Jan-21	29-Jan-21	22-Jan-21	24-Feb-21	33	198,000	8-Mar-21	12	72,000
380	WRIGHT IMPLEMENT	28-Jan-20	95	95	CHECK	26-Jan-20	26-Jan-20	26-Jan-20	5-Aug-20	192	18,152	14-Aug-20	9	851
381														
382	Totals			501,156							12,794,170			1,269,386
383														
384									Other O&M Payment Lag Days:		25.53			2.53

Atmos Energy Corporation-Kentucky
 Other O&M Payment and Check Clearing Lag
 For the CWC Study Test Year Ended March 31, 2021

CWC WP 5-2

Line No.	Vendor	Invoice Date	Invoice Amount	Division 009 Amount	Payment Type	Service Period		Midpoint Service	Date Paid	Payment lag	Weighted Payment Lag	Date Cleared	Clearing Lag	Weighted Clearing Lag	
		<i>a</i>	<i>b</i>	<i>c</i>	<i>d</i>	<i>e</i>	<i>f</i>	<i>g</i>	<i>h</i>	<i>i</i>	= i -(h or b)	<i>k</i> = (<i>j</i> * <i>d</i>)	<i>l</i>	<i>m</i> = (<i>l</i> - <i>i</i>)	<i>n</i> = (<i>m</i> * <i>d</i>)
1	ELEMENT FLEET	6-Apr-20	1,100,412	103,540	Direct Deposit	1-Mar-20	31-Mar-20	16-Mar-20	7-Apr-20	22	2,277,871	7-Apr-20	0	-	
2	ELEMENT FLEET	5-May-20	1,155,527	97,455	Direct Deposit	1-Apr-20	30-Apr-20	15-Apr-20	8-May-20	23	2,241,476	8-May-20	0	-	
3	ELEMENT FLEET	8-Jun-20	1,242,247	92,629	Direct Deposit	1-May-20	31-May-20	16-May-20	9-Jun-20	24	2,223,091	9-Jun-20	0	-	
4	ELEMENT FLEET	6-Jul-20	1,132,601	96,045	Direct Deposit	1-Jun-20	30-Jun-20	15-Jun-20	8-Jul-20	23	2,209,036	8-Jul-20	0	-	
5	ELEMENT FLEET	5-Aug-20	1,019,995	19,503	Direct Deposit	1-Jul-20	31-Jul-20	16-Jul-20	6-Aug-20	21	409,558	6-Aug-20	0	-	
6	ELEMENT FLEET	8-Sep-20	1,028,842	74,098	Direct Deposit	1-Aug-20	31-Aug-20	16-Aug-20	9-Sep-20	24	1,778,340	9-Sep-20	0	-	
7	ELEMENT FLEET	5-Oct-20	892,975	15,762	Direct Deposit	1-Sep-20	30-Sep-20	15-Sep-20	6-Oct-20	21	331,001	6-Oct-20	0	-	
8	ELEMENT FLEET	10-Nov-20	903,733	44,364	Direct Deposit	1-Oct-20	31-Oct-20	16-Oct-20	12-Nov-20	27	1,197,839	12-Nov-20	0	-	
9	ELEMENT FLEET	7-Dec-20	957,911	72,974	Direct Deposit	1-Nov-20	30-Nov-20	15-Nov-20	8-Dec-20	23	1,678,399	8-Dec-20	0	-	
10	ELEMENT FLEET	5-Jan-21	1,026,422	72,232	Direct Deposit	1-Dec-20	31-Dec-20	16-Dec-20	6-Jan-21	21	1,516,871	6-Jan-21	0	-	
11	ELEMENT FLEET	5-Feb-21	1,241,727	38,442	Direct Deposit	1-Jan-21	31-Jan-21	16-Jan-21	9-Feb-21	24	922,617	9-Feb-21	0	-	
12	ELEMENT FLEET	8-Mar-21	1,063,457	81,982	Direct Deposit	1-Feb-21	28-Feb-21	14-Feb-21	9-Mar-21	23	1,885,585	9-Mar-21	0	-	
13															
14				809,026							18,671,684			-	
15															
16	Total Normalized Other O&M			20,113,734				Other O&M Payment Lag Days:			23.08			0.00	
17															
18	Element Fleet Percent of Total			4.02%											
19															
20	O&M Sample Excluding Element Fleet			501,093											
21															
22	O&M Sample with Element Fleet at percent of total from above			522,093											
23															
24	Adjusted Element Fleet amount in sample			21,000											

ATO-CWC6

Atmos Energy Corporation-Kentucky
Taxes Other Than Income Taxes
For the CWC Study Test Year Ended March 31, 2021

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:	0	13.0	-
3				
4	Federal Unemployment - Paid quarterly in arrears at the			
5	end of the month following each quarter plus payroll service lag:	0	83.6	-
6				
7	State Unemployment - Paid quarterly in arrears at the end			
8	end of the month following each quarter plus payroll service lag:	<u>355,960</u>	83.6	<u>83.63</u>
9				
10	Total Payroll Taxes	355,960		83.63
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			346.39
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			40.19
22				
23	Public Service Commission Assessment			
24	Assessment are prepaid to the Commission annually and			
25	are included in prepayments in rate base			0.00
26				
27	DOT - Payment for the pipeline safety user fee for the			
28	current fiscal year is due by May 30th			59.00

Atmos Energy Corporation-Kentucky
Federal Income Taxes
For the CWC Study Test Year Ended March 31, 2021

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	<u>Federal Income Tax Payments:</u>						
2	June 15, 2020	4/1/2020	3/31/2021	182.50	25.00%	(107.50)	(26.88)
3	September 15, 2020	4/1/2020	3/31/2021	182.50	25.00%	(15.50)	(3.88)
4	December 15, 2020	4/1/2020	3/31/2021	182.50	25.00%	75.50	18.88
5	March 15, 2020	4/1/2020	3/31/2021	182.50	25.00%	(199.50)	(49.88)
6							
7					100.00%		<u>(61.75)</u>

Atmos Energy Corporation-Kentucky
State Income Taxes
For the CWC Study Test Year Ended March 31, 2021

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	<u>State Income Tax Payments:</u>						
2	June 15, 2020	4/1/2020	3/31/2021	182.50	25.00%	(107.50)	(26.88)
3	September 15, 2020	4/1/2020	3/31/2021	182.50	25.00%	(15.50)	(3.88)
4	December 15, 2020	4/1/2020	3/31/2021	182.50	25.00%	75.50	18.88
5	March 15, 2020	4/1/2020	3/31/2021	182.50	25.00%	(199.50)	(49.88)
6							
7					100.00%		<u>(61.75)</u>

ATO-CWC9

Atmos Energy Corporation-Kentucky
Long Term Debt
For the CWC Study Test Year Ended March 31, 2021

Atmos Consolidated Balances

Line No.	Lender	Maturity	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)																	
1	MTN 1995-1	12/31/2025	SEMI ANNUAL	6/15/2020	12/15/2020											91.25	\$ 667,000	0.35%	0.32
2	Debentures	07/15/28	SEMI ANNUAL	7/15/2020	1/15/2021											91.25	\$ 10,125,000	5.34%	4.87
3	SrNote 5.95%	10/15/34	SEMI ANNUAL	4/15/2020	10/15/2020											91.25	\$ 11,900,000	6.28%	5.73
4	SrNote 3.00%	06/15/2027	SEMI ANNUAL	6/15/2020	12/15/2020											91.25	\$ 15,000,000	7.91%	7.22
5	Sr Note 5.50%	06/15/2041	SEMI ANNUAL	6/15/2020	12/15/2020											91.25	\$ 22,000,000	11.60%	10.59
6	SrNote 4.15%	1/15/2043	SEMI ANNUAL	7/15/2020	1/15/2021											91.25	\$ 20,750,000	10.95%	9.99
7	SrNote 4.125%	10/15/2044	SEMI ANNUAL	4/15/2020	10/15/2020											91.25	\$ 30,937,500	16.32%	14.89
8	SrNote 4.300%	10/1/2048	SEMI ANNUAL	4/1/2020	10/1/2020											91.25	\$ 25,800,000	13.61%	12.42
	SrNote 4.125%	3/15/2049	SEMI ANNUAL	9/15/2020	3/15/2021											91.25	\$ 18,562,500	9.79%	8.93
	SrNote 2.625%	9/15/2029	SEMI ANNUAL	9/15/2020	3/15/2021											91.25	\$ 7,875,000	4.15%	3.79
	SrNote 3.375%	9/15/2049	SEMI ANNUAL	9/15/2020	3/15/2021											91.25	\$ 16,875,000	8.90%	8.12
	SrNote 1.5%	1/15/2031	SEMI ANNUAL	1/15/2021												91.25	\$ 4,500,000	2.37%	2.17
9	LTD Term Loan Varied	4/9/2021	QUARTERLY	7/9/2020	10/9/2020	1/11/2021	10/31/2017	11/30/2017	12/29/2017	1/31/2018	2/28/2018	3/29/2018	4/30/2018	5/31/2018	6/29/2018	91.25	\$ 4,590,139	2.42%	2.21
10																			
11	WEIGHTED AVERAGE LEAD DAYS OF LONG TERM DEBT EXPENSE																\$ 189,582,139	100.00%	<u>91.25</u>

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

APPLICATION OF ATMOS ENERGY	)	
	)	
CORPORATION FOR AN ADJUSTMENT	)	Case No. 2021-00214
	)	
OF RATES AND TARIFF MODIFICATIONS	)	

DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS

RATE OF RETURN

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Exhibit

Exhibit DWD-1

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 241, 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 before over 25 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, and one American Arbitration Association panel 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.

1 I am also a member of the National Association of Certified Valuation
2 Analysts (“NACVA”) and was awarded the professional designation “Certified
3 Valuation Analyst” by the NACVA in 2015.

4 I am a graduate of the University of Pennsylvania, where I received a
5 Bachelor of Arts degree in Economic History. I have also received a Master of
6 Business Administration with high honors and concentrations in Finance and
7 International Business from Rutgers University.

8 The details of my educational background and expert witness appearances
9 are shown in Appendix A.

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

12 A. The purpose of my testimony is to present evidence and provide a recommendation
13 regarding Atmos Energy Corporation’s (“Atmos Energy” or the “Company”) return
14 on common equity (“ROE”) for its natural gas distribution operations in Kentucky.

15 **Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR**
16 **RECOMMENDATION?**

17 A. Yes. I have prepared Exhibit No. DWD-1, consisting of Schedules DWD-1 through
18 DWD-8, which were prepared by me or under my direction.

19 **Q. WHAT IS YOUR RECOMMENDED ROE FOR ATMOS ENERGY?**

20 A. I recommend that the Commission authorize Atmos Energy the opportunity to earn
21 an ROE of 10.35% on its rate base. The ratemaking capital structure and cost of
22 long-term debt is sponsored by Company Witness Christian. The overall rate of
23 return is summarized on page 1 of Schedule 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	42.77%	4.00%	1.71%
Short-Term Debt	0.18%	25.17%	0.05%
Common Equity	<u>57.05%</u>	<u>10.35%</u>	<u>5.90%</u>
Total	<u>100.00%</u>		<u>7.66%</u>

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR RECOMMENDED COMMON EQUITY COST RATE.

A. My recommended common equity cost rate of 10.35% is summarized on page 2 of Schedule 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 applying 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 seven natural gas distribution utilities ("Utility Proxy Group") whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a proxy group of 48 domestic, non-price regulated

¹ *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

² *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922).

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	9.44%
Risk Premium Model	10.96%
Capital Asset Pricing Model	11.75%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	<u>12.42%</u>
Indicated Range	9.44% - 12.42%
Size Adjustment	0.20%
Credit Risk Adjustment	-0.10%
Flotation Cost Adjustment	<u>0.04%</u>
Recommended Range	9.58% - 12.66%
Recommended Cost of Common Equity	<u>10.35%</u>

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 9.44% and 12.42% before any Company-specific adjustments. As ROE models are based on market data, the indicated results of the models would reflect current and expected capital markets, including the impacts of COVID-19. I then adjusted the indicated range by 0.20% and negative 0.10% to reflect the Company’s smaller relative size and lower credit risk, as compared to the Utility Proxy Group companies, and by 0.04% for flotation costs.³ These adjustments resulted in a Company-specific indicated range of common equity cost rates between 9.58% and 12.66%.

The wide range of model results may reflect increased uncertainty related to the COVID-19 pandemic and unknown timeframe for when economic conditions

³ See Section VII for a detailed discussion of my cost of common equity adjustments.

1 will normalize as vaccinations ramp up and the public health crises subsides.
2 Because of this uncertainty, I recommend an ROE for the Company toward the
3 lower end of my Company-specific range, specifically 10.35%.

4 **Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY**
5 **ORGANIZED?**

6 A. The remainder of my Direct Testimony is organized as follows:

- 7 • Section III – Provides a summary of financial theory and regulatory principles
8 pertinent to the development of the cost of common equity;
- 9 • Section IV – Explains my selection of the Utility Proxy Group used to develop
10 my Cost of Common Equity analytical results;
- 11 • Section V – Describes the analyses on which my Cost of Common Equity
12 recommendation is based;
- 13 • Section VI – Summarizes my common equity cost rate before adjustments to
14 reflect Company-specific factors;
- 15 • Section VII – Explains my adjustments to my common equity cost rate to reflect
16 Company-specific factors; and
- 17 • Section VIII – Presents my conclusions.

18 **III. GENERAL PRINCIPLES**

19 **Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN**
20 **ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST**
21 **RATE OF 10.35%?**

22 A. In unregulated industries, marketplace competition is the principal determinant of
23 the price of products or services. For regulated public utilities, regulation must act

1 as a substitute for marketplace competition. Assuring that the utility can fulfill its
2 obligations to the public, while providing safe and reliable service at all times,
3 requires a level of earnings sufficient to maintain the integrity of presently invested
4 capital. Sufficient earnings also permit the attraction of needed new capital at a
5 reasonable cost, for which the utility must compete with other firms of comparable
6 risk, consistent with the fair rate of return standards established by the U.S.
7 Supreme Court in the previously cited *Hope* and *Bluefield* cases.

8 The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*,
9 when it stated:

10 The rate-making process under the Act, *i.e.*, the fixing of ‘just and
11 reasonable’ rates, involves a balancing of the investor and the
12 consumer interests. Thus we stated in the Natural Gas Pipeline Co.
13 case that ‘regulation does not insure that the business shall produce
14 net revenues.’ 315 U.S. at page 590, 62 S.Ct. at page 745. But such
15 considerations aside, the investor interest has a legitimate concern
16 with the financial integrity of the company whose rates are being
17 regulated. From the investor or company point of view it is
18 important that there be enough revenue not only for operating
19 expenses but also for the capital costs of the business. These include
20 service on the debt and dividends on the stock. Cf. *Chicago & Grand*
21 *Trunk R. Co. v. Wellman*, 143 U.S. 339, 345, 346 12 S.Ct. 400,402.
22 By that standard the return to the equity owner should be
23 commensurate with returns on investments in other enterprises
24 having corresponding risks. That return, moreover, should be
25 sufficient to assure confidence in the financial integrity of the
26 enterprise, so as to maintain its credit and to attract capital.⁴

27 Consistent with the findings in *Hope*, the Commission’s decision in this
28 proceeding should provide the Company with the opportunity to earn a return that
29 is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to

⁴ *Hope*, 320 U.S. 591 (1944), at 603.

1 ensure their financial integrity; and (3) commensurate with returns on investments
2 in enterprises having corresponding risks.

3 Also, the required return for a regulated public utility is established on a
4 stand-alone basis, i.e., for the utility operating company at issue in a rate case.
5 When funding is provided by a corporate entity to an operating division or business
6 unit within the entity, the allowed return still must be sufficient to provide an
7 incentive to allocate equity capital to the business unit rather than other internal or
8 external investment opportunities. That is, the regulated operating division must
9 compete for capital with all the operating divisions within the corporate entity, and
10 with other, similarly situated companies. In that regard, investors value corporate
11 entities on a sum-of-the-parts basis and expect each division within the parent
12 company to provide an appropriate risk-adjusted return.

13 It therefore is important that the authorized ROE reflects the risks and
14 prospects of the utility's operations and supports the utility's financial integrity
15 from a stand-alone perspective as measured by their combined business and
16 financial risks. Consequently, the ROE authorized in this proceeding should be
17 sufficient to support the operational (*i.e.*, business risk) and financing (*i.e.*, financial
18 risk) of the Company's Kentucky utility operations on a stand-alone basis.

19 **Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF**
20 **CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?**

21 A. Regulated utilities primarily use common stock and long-term debt to finance their
22 permanent property, plant, and equipment (*i.e.*, rate base). The fair rate of return
23 for a regulated utility is based on its weighted average cost of capital, in which, as

1 noted earlier, the costs of the individual sources of capital are weighted by their
2 respective book values.

3 The cost of capital is the return investors require to make an investment in
4 a firm. Investors will provide funds to a firm only if the return that they *expect* is
5 equal to, or greater than, the return that they *require* to accept the risk of providing
6 funds to the firm.

7 The cost of capital (that is, the combination of the costs of debt and equity)
8 is based on the economic principle of “opportunity costs.” Investing in any asset
9 (whether debt or equity securities) represents a forgone opportunity to invest in
10 alternative assets. For any investment to be sensible, its expected return must be at
11 least equal to the return expected on alternative, comparable risk investment
12 opportunities. Because investments with like risks should offer similar returns, the
13 opportunity cost of an investment should equal the return available on an
14 investment of comparable risk.

15 Whereas the cost of debt is contractually defined and can be directly
16 observed as the interest rate or yield on debt securities, the cost of common equity
17 must be estimated based on market data and various financial models. Because the
18 cost of common equity is premised on opportunity costs, the models used to
19 determine it are typically applied to a group of “comparable” or “proxy” companies.

20 In the end, the estimated cost of capital should reflect the return that
21 investors require in light of the subject company’s business and financial risks, and
22 the returns available on comparable investments.

1 **Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS**
2 **GUARANTEED?**

3 A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the rate-setting
4 process should provide the utility a reasonable opportunity to recover its return of,
5 and return on, its prudently incurred investments, but it does not guarantee that
6 return. While a utility may have control over some factors that affect the ability to
7 earn its authorized return (*e.g.*, management performance, operating and
8 maintenance expenses, etc.), there are several factors beyond a utility's control that
9 affect its ability to earn its authorized return. Those may include factors such as
10 weather, the economy, and the prevalence and magnitude of regulatory lag.

11 A. **Business Risk**

12 **Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS**
13 **IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.**

14 A. The investor-required return on common equity reflects investors' assessment of
15 the total investment risk of the subject firm. Total investment risk is often discussed
16 in the context of business and financial risk.

17 Business risk reflects the uncertainty associated with owning a company's
18 common stock without the company's use of debt and/or preferred stock financing.
19 One way of considering the distinction between business and financial risk is to
20 view the former as the uncertainty of the expected earned return on common equity,
21 assuming the firm is financed with no debt.

22 Examples of business risks generally faced by utilities include, but are not
23 limited to, the regulatory environment, mandatory environmental compliance
24 requirements, customer mix and concentration of customers, service territory

1 economic growth, market demand, risks and uncertainties of supply, operations,
2 capital intensity, size, the degree of operating leverage, and the like, all of which
3 have a direct bearing on earnings. Although analysts, including rating agencies,
4 may categorize business risks individually, as a practical matter, such risks are
5 interrelated and not wholly distinct from one another. Therefore, it is difficult to
6 specifically and numerically quantify the effect of any individual risk on investors'
7 required return, *i.e.*, the cost of capital. For determining an appropriate return on
8 common equity, the relevant issue is where investors see the subject company as
9 falling within a spectrum of risk. To the extent investors view a company as being
10 exposed to high risk, the required return will increase, and vice versa.

11 For regulated utilities, business risks are both long-term and near-term in
12 nature. Whereas near-term business risks are reflected in year-to-year variability in
13 earnings and cash flow brought about by economic or regulatory factors, long-term
14 business risks reflect the prospect of an impaired ability of investors to obtain both
15 a fair rate of return on, and return of, their capital. Moreover, because utilities
16 accept the obligation to provide safe, adequate and reliable service at all times (in
17 exchange for a reasonable opportunity to earn a fair return on their investment),
18 they generally do not have the option to delay, defer, or reject capital investments.
19 Because those investments are capital-intensive, utilities generally do not have the
20 option to avoid raising external funds during periods of capital market distress, if
21 necessary.

22 Because utilities invest in long-lived assets, long-term business risks are of
23 paramount concern to equity investors. That is, the risk of not recovering the return

1 on their investment extends far into the future. The timing and nature of events that
2 may lead to losses, however, also are uncertain and, consequently, those risks and
3 their implications for the required return on equity tend to be difficult to quantify.
4 Regulatory commissions (like investors who commit their capital) must review a
5 variety of quantitative and qualitative data and apply their reasoned judgment to
6 determine how long-term risks weigh in their assessment of the market-required
7 return on common equity.

8 **B. Financial Risk**

9 **Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS**
10 **IMPORTANT IN DETERMINING A FAIR RATE OF RETURN.**

11 A. Financial risk is the additional risk created by the introduction of debt and preferred
12 stock into the capital structure. The higher the proportion of debt and preferred
13 stock in the capital structure, the higher the financial risk to common equity owners
14 (*i.e.*, failure to receive dividends due to default or other covenants). Therefore,
15 consistent with the basic financial principle of risk and return, common equity
16 investors demand higher returns as compensation for bearing higher financial risk.

17 **Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S**
18 **COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS**
19 **(*I.E.*, INVESTMENT RISK)?**

20 A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of,
21 similar combined business and financial risks (*i.e.*, total risk) faced by bond
22 investors.⁵ Although specific business or financial risks may differ between

⁵ 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 be at A+, A, or A-. Similarly, risk distinction for

1 companies, the same bond/credit rating indicates that the combined risks are
2 roughly similar from a debtholder perspective. The caveat is that these debtholder
3 risk measures do not translate directly to risks for common equity.

4 **Q. DO RATING AGENCIES ACCOUNT FOR COMPANY SIZE IN THEIR**
5 **BOND RATINGS?**

6 A. No. Neither Standard & Poor's ("S&P") nor Moody's have minimum company
7 size requirements for any given rating level. This means, all else equal, a relative
8 size analysis must be conducted for equity investments in companies with similar
9 bond ratings.

10 **IV. ATMOS ENERGY'S KENTUCKY OPERATIONS AND THE UTILITY**
11 **PROXY GROUP**

12 **Q. ARE YOU FAMILIAR WITH ATMOS ENERGY'S OPERATIONS?**

13 A. Yes. Atmos Energy's Kentucky operations serve approximately 183,000
14 customers.⁶ Atmos Energy's Kentucky gas operations are not publicly-traded as
15 they comprise an operating division of Atmos Energy Corporation ("ATO" or the
16 "Company"), which operates in eight states⁷ and serves approximately 3.3 million
17 gas⁸ and is publicly-traded under symbol ATO.

18 **Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE**
19 **UTILITY PROXY GROUP.**

20 A. The companies selected for the Utility Proxy Group met the following criteria:

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.

⁶ Atmos Energy Corporation, 2020 SEC Form 10-K, at 4.

⁷ *Ibid.*, In addition to Kentucky, ATO also serves customers in Texas, Louisiana, Mississippi,
Virginia, Colorado, Kansas, and Tennessee.

⁸ *Ibid.*

- 1 (i) They were included in the Natural Gas Utility Group of *Value Line's*
2 *Standard Edition (Value Line)* (May 28, 2021);
- 3 (ii) They have 60% or greater of fiscal year 2020 total operating income derived
4 from, and 60% or greater of fiscal year 2020 total assets attributable to,
5 regulated gas distribution operations;
- 6 (iii) At the time of preparation of this testimony, they had not publicly
7 announced that they were involved in any major merger or acquisition
8 activity (*i.e.*, one publicly-traded utility merging with or acquiring another);
- 9 (iv) They have not cut or omitted their common dividends during the five years
10 ended 2020 or through the time of preparation of this testimony;
- 11 (v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg")
12 adjusted betas;
- 13 (vi) They have positive *Value Line* five-year dividends per share ("DPS")
14 growth rate projections; and
- 15 (vii) They have *Value Line*, Zacks, Yahoo! Finance, or Bloomberg consensus
16 five-year earnings per share ("EPS") growth rate projections.

17 The following seven companies met these criteria: Atmos Energy
18 Corporation, New Jersey Resources Corp., Northwest Natural Holding Company,
19 One Gas, Inc., South Jersey Industries, Inc., Southwest Gas Holdings, Inc., and
20 Spire, Inc.

21 **Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN**
22 **ESTIMATING THE ROE FOR THE COMPANY?**

23 A. Because the Company is not publicly traded and does not have publicly traded
24 equity securities, it is necessary to develop groups of publicly traded, comparable
25 companies to serve as "proxies" for the Company. In addition to the analytical
26 necessity of doing so, the use of proxy companies is consistent with the *Hope* and
27 *Bluefield* comparable risk standards, as discussed above. I have selected two proxy

1 groups that, in my view, are fundamentally risk-comparable to the Company: a
2 Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable
3 in total risk to the Utility Proxy Group.⁹

4 Even when proxy groups are carefully selected, it is common for analytical
5 results to vary from company to company. Despite the care taken to ensure
6 comparability, because no two companies are identical, market expectations
7 regarding future risks and prospects will vary within the proxy group. It therefore
8 is common for analytical results to reflect a seemingly wide range, even for a group
9 of similarly situated companies. At issue is how to estimate the ROE from within
10 that range. That determination will be best informed by employing a variety of
11 sound analyses that necessarily must consider the sort of quantitative and
12 qualitative information discussed throughout my Direct Testimony. Additionally,
13 a relative risk analysis between the Company and the Utility Proxy Group must be
14 made to determine whether or not explicit Company-specific adjustments need to
15 be made to the Utility Proxy Group indicated results.

16 **V. COMMON EQUITY COST RATE MODELS**

17 **Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE**
18 **MARKET BASED?**

19 **A.** Yes. A public utility must compete for equity in capital markets along with all other
20 companies of comparable risk, which includes non-utilities. The cost of common
21 equity is thus determined based on equity market expectations for the returns of
22 those comparable risk companies. If an individual investor is choosing to invest

⁹ The development of the Non-Price Regulated Proxy Group is explained in more detail in Section V.

1 their capital among companies of comparable risk, they will choose a company
2 providing a higher return over a company providing a lower return.

3 **Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET BASED?**

4 A. Yes. The DCF model uses market prices in developing the model's dividend yield
5 component. The RPM uses bond ratings and expected bond yields that reflect the
6 market's assessment of bond/credit risk. In addition, beta coefficients (β), which
7 reflect the market/systematic risk component of equity risk premium, are derived
8 from regression analyses of market prices. The Predictive Risk Premium Model
9 ("PRPM") uses monthly market returns in addition to expectations of the risk-free
10 rate. The CAPM is market based for many of the same reasons that the RPM is
11 market based (*i.e.*, the use of expected bond yields and betas). Selection criteria for
12 comparable risk non-price regulated companies are based on regression analyses of
13 market prices and reflect the market's assessment of total risk.

14 **Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE**
15 **THE COMPANY'S ROE?**

16 A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM,
17 which I apply to the Utility Proxy Group described above. I also applied these same
18 models to a Non-Price Regulated Proxy Group described later in this section.

19 I rely on these models because reasonable investors use a variety of tools
20 and do not rely exclusively on a single source of information or single model.
21 Moreover, the models on which I rely focus on different aspects of return
22 requirements, and provide different insights to investors' views of risk and return.
23 The DCF model, for example, estimates the investor-required return assuming a

1 constant expected dividend yield and growth rate in perpetuity, while Risk
2 Premium-based methods (*i.e.*, the RPM and CAPM approaches) provide the ability
3 to reflect investors' views of risk, future market returns, and the relationship
4 between interest rates and the cost of common equity. Just as the use of market
5 data for the Utility Proxy Group adds the reliability necessary to inform expert
6 judgment in arriving at a recommended common equity cost rate, the use of
7 multiple generally accepted common equity cost rate models also adds reliability
8 and accuracy when arriving at a recommended common equity cost rate.

9 **A. Discounted Cash Flow Model**

10 **Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?**

11 A. The theory underlying the DCF model is that the present value of an expected future
12 stream of net cash flows during the investment holding period can be determined
13 by discounting those cash flows at the cost of capital, or the investors' capitalization
14 rate. DCF theory indicates that an investor buys a stock for an expected total return
15 rate, which is derived from the cash flows received from dividends and market price
16 appreciation. Mathematically, the dividend yield on market price plus a growth
17 rate equals the capitalization rate; *i.e.*, the total common equity return rate expected
18 by investors as shown below:

19
$$K_e = (D_0 (1+g))/P + g$$

20 where:

21 K_e = the required Return on Common Equity;
22 D_0 = the annualized Dividend Per Share;
23 P = the current stock price; and
24 g = the growth rate.

1 **Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?**

2 A. I used the single-stage constant growth DCF model in my analyses.

3 **Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING**
4 **THE CONSTANT GROWTH DCF MODEL.**

5 A. The unadjusted dividend yields are based on the proxy companies' dividends as of
6 May 28, 2021, divided by the average closing market price for the 60 trading days
7 ended May 28, 2021.¹⁰

8 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.**

9 A. Because dividends are paid periodically (*e.g.* quarterly), as opposed to continuously
10 (daily), an adjustment must be made to the dividend yield. This is often referred to
11 as the discrete, or the Gordon Periodic, version of the DCF model.

12 DCF theory calls for using the full growth rate, or D_1 , in calculating the
13 model's dividend yield component. Since the companies in the Utility Proxy Group
14 increase their quarterly dividends at various times during the year, a reasonable
15 assumption is to reflect one-half the annual dividend growth rate in the dividend
16 yield component, or $D_{1/2}$. Because the dividend should be representative of the next
17 12-month period, this adjustment is a conservative approach that does not overstate
18 the dividend yield. Therefore, the actual average dividend yields in Column 1, page
19 1 of Schedule DWD-2 have been adjusted upward to reflect one-half the average
20 projected growth rate shown in Column 6.

¹⁰ See, column 1, page 1 of Schedule DWD-2.

1 **Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY**
2 **TO THE UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF**
3 **MODEL.**

4 A. Investors are likely to rely on widely available financial information services, such
5 as *Value Line*, Zacks, Yahoo! Finance, and Bloomberg. Investors realize that
6 analysts have significant insight into the dynamics of the industries and individual
7 companies they analyze, as well as companies' ability to effectively manage the
8 effects of changing laws and regulations, and ever-changing economic and market
9 conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in
10 my DCF analysis.

11 Over the long run, there can be no growth in DPS without growth in EPS.
12 Security analysts' earnings expectations have a more significant influence on
13 market prices than dividend expectations. Thus, using earnings growth rates in a
14 DCF analysis provides a better match between investors' market price appreciation
15 expectations and the growth rate component of the DCF.

16 **Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL**
17 **RESULTS.**

18 A. As shown on page 1 of Schedule DWD-2, for the Utility Proxy Group, the mean
19 result of applying the single-stage DCF model is 9.57%, the median result is 9.30%,
20 and the average of the two is 9.44%. In arriving at a conclusion for the constant
21 growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied
22 on an average of the mean and the median results of the DCF. This approach

1 considers all the proxy utilities' results, while mitigating the high and low outliers
2 of those individual results.

3 **B. The Risk Premium Model**

4 **Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.**

5 A. The RPM is based on the fundamental financial principle of risk and return; namely,
6 that investors require greater returns for bearing greater risk. The RPM recognizes
7 that common equity capital has greater investment risk than debt capital, as
8 common equity shareholders are behind debt holders in any claim on a company's
9 assets and earnings. As a result, investors require higher returns from common
10 stocks than from bonds to compensate them for bearing the additional risk.

11 While it is possible to directly observe bond returns and yields, investors'
12 required common equity returns cannot be directly determined or observed.
13 According to RPM theory, one can estimate a common equity risk premium over
14 bonds (either historically or prospectively) and use that premium to derive a cost
15 rate of common equity. The cost of common equity equals the expected cost rate
16 for long-term debt capital, plus a risk premium over that cost rate, to compensate
17 common shareholders for the added risk of being unsecured and last-in-line for any
18 claim on the corporation's assets and earnings upon liquidation.

19 **Q. PLEASE EXPLAIN HOW YOU DERIVED YOUR INDICATED COST OF**
20 **COMMON EQUITY BASED ON THE RPM.**

21 A. To derive my indicated cost of common equity under the RPM, I used two risk
22 premium methods. The first method was the PRPM and the second method was a
23 risk premium model using a total market approach. The PRPM estimates the risk-

1 return relationship directly, while the total market approach indirectly derives a risk
2 premium by using known metrics as a proxy for risk.

3 **1. The Predictive Risk Premium Model**

4 **Q. PLEASE EXPLAIN THE PRPM.**

5 A. The PRPM, published in the *Journal of Regulatory Economics*,¹¹ was developed
6 from the work of Robert F. Engle, who shared the Nobel Prize in Economics in
7 2003 “for methods of analyzing economic time series with time-varying volatility
8 (“ARCH”)”.¹² Engle found that volatility changes over time and is related from
9 one period to the next, especially in financial markets. Engle discovered that
10 volatility of prices and returns cluster over time and is therefore highly predictable
11 and can be used to predict future levels of risk and risk premiums.

12 The PRPM estimates the risk-return relationship directly, as the predicted
13 equity risk premium is generated by predicting volatility or risk. The PRPM is not
14 based on an estimate of investor behavior, but rather on an evaluation of the results
15 of that behavior (*i.e.*, the variance of historical equity risk premiums).

16 The inputs to the model are the historical returns on the common shares of
17 each Utility Proxy Group company minus the historical monthly yield on long-term
18 U.S. Treasury securities through May 2021. Using a generalized form of ARCH,
19 known as GARCH, I calculated each Utility Proxy Group company’s projected
20 equity risk premium using Eviews[®] statistical software. When the GARCH model
21 is applied to the historical return data, it produces a predicted GARCH variance

¹¹ 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, Ph.D. The Journal of Regulatory Economics (December 2011), 40:261-278.

¹² www.nobelprize.org.

series¹³ and a GARCH coefficient¹⁴. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it¹⁵ produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 2.88%¹⁶ to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from Blue Chip Financial Forecasts (*Blue Chip*).¹⁷ The mean PRPM indicated common equity cost rate for the Utility Proxy Group is 11.67%, the median is 11.19%, and the average of the two is 11.43%. Consistent with my reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 11.43%.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Schedules DWD-3 and 4, the risk-free rate adopted for applications of the RPM and CAPM is 2.88%. 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 third calendar quarter of 2022, and long-term projections for the years 2023 to 2027 and 2028 to 2032.

¹³ Illustrated on Columns 1 and 2, page 2 of Schedule DWD-3.

¹⁴ Illustrated on Column 4, page 2 of Schedule DWD-3.

¹⁵ Annualized Return = $(1 + \text{Monthly Return})^{12} - 1$

¹⁶ See Column 6, page 2 of Schedule DWD-3.

¹⁷ *Blue Chip Financial Forecasts*, June 1, 2021, at page 2 and 14.

1 **Q. WHY DO YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN**
2 **YOUR ANALYSES?**

3 A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is
4 consistent with the long-term cost of capital to public utilities measured by the
5 yields on Moody's A2-rated public utility bonds; the long-term investment horizon
6 inherent in utilities' common stocks; and the long-term life of the jurisdictional rate
7 base to which the allowed fair rate of return (*i.e.*, cost of capital) will be applied.
8 In contrast, short-term U.S. Treasury yields are more volatile and largely a function
9 of Federal Reserve monetary policy.

10 **2. The Total Market Risk Premium Approach**

11 **Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.**

12 A. The total market approach RPM adds a prospective public utility bond yield to an
13 average of: 1) an equity risk premium that is derived from a beta-adjusted total
14 market equity risk premium, 2) an equity risk premium based on the S&P Utilities
15 Index, and 3) an equity risk premium based on authorized ROEs for gas distribution
16 utilities.

17 **Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF**
18 **3.99% APPLICABLE TO THE UTILITY PROXY GROUP.**

19 A. The first step in the total market approach RPM analysis is to determine the
20 expected bond yield. Because both ratemaking and the cost of capital, including
21 common equity cost rate, are prospective in nature, a prospective yield on similarly-
22 rated long-term debt is essential. I relied on a consensus forecast of about 50
23 economists of the expected yield on Aaa-rated corporate bonds for the six calendar
24 quarters ending with the third calendar quarter of 2022, and *Blue Chip's* long-term

1 projections for 2023 to 2027, and 2028 to 2032. As shown on line 1, page 3 of
2 Schedule DWD-3, the average expected yield on Moody's Aaa-rated corporate
3 bonds is 3.56%. To derive an expected yield on Moody's A2-rated public utility
4 bonds, I made an upward adjustment of 0.39%, which represents a recent spread
5 between Aaa-rated corporate bonds and A2-rated public utility bonds, in order to
6 adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public
7 utility bond yield.¹⁸ Adding that recent 0.39% spread to the expected Aaa-rated
8 corporate bond yield of 3.56% results in an expected A2-rated public utility bond
9 yield of 3.95%.

10 I then reviewed the average credit rating for the Utility Proxy Group from
11 Moody's to determine if an adjustment to the estimated A2-rated public utility bond
12 was necessary. Since the Utility Proxy Group's average Moody's long-term issuer
13 rating is A2/A3, another adjustment to the expected A2-rated public utility bond is
14 needed to reflect the difference in bond ratings. An upward adjustment of 0.04%,
15 which represents one-sixth of a recent spread between A2-rated and Baa2-rated
16 public utility bond yields, is necessary to make the A2 prospective bond yield
17 applicable to an A2/A3-rated public utility bond.¹⁹ Adding the 0.04% to the 3.96%
18 prospective A2-rated public utility bond yield results in a 3.99% expected bond
19 yield applicable to the Utility Proxy Group.

¹⁸ As shown on line 2 and explained in note 2, page 3 of Schedule DWD-3.

¹⁹ As shown on line 4 and explained in note 3, page 3 of Schedule DWD-3. Moody's does not provide public utility bond yields for A2/A3-rated bonds. As such, it was necessary to estimate the difference between A2-rated and A2/A3-rated public utility bonds. Because there are three steps between Baa2 and A2 (Baa2 to Baa1, Baa1 to A3, and A3 to A2) I assumed an adjustment of one-sixth of the difference between the A2-rated and Baa2-rated public utility bond yield was appropriate.

Table 3: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield²⁰

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (<i>Blue Chip</i>)	3.56%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.39%
Adjustment to Reflect the Utility Proxy Group's Average Moody's Bond Rating of A2/A3	<u>0.04%</u>
Prospective Bond Yield Applicable to the Utility Proxy Group	<u>3.99%</u>

To develop the indicated ROE using the total market approach RPM, this prospective bond yield is then added to the average of the three different equity risk premiums described below.

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 coefficient. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 9, page 8 of Schedule 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, two *Value Line*-based equity risk premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

²⁰ As shown on page 3 of Schedule DWD-3.

1 **Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED**
2 **ON LONG-TERM HISTORICAL DATA?**

3 A. To derive a historical market equity risk premium, I used the most recent holding
4 period returns for the large company common stocks from the Stocks, Bonds, Bills,
5 and Inflation (SBBI) Yearbook 2021 (SBBI - 2021)²¹ less the average historical
6 yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2020. Using
7 holding period returns over a very long time is appropriate because it is consistent
8 with the long-term investment horizon presumed by investing in a going concern,
9 *i.e.*, a company expected to operate in perpetuity.

10 SBBI's long-term arithmetic mean monthly total return rate on large
11 company common stocks was 11.94%, and the long-term arithmetic mean monthly
12 yield on Moody's Aaa/Aa-rated corporate bonds was 6.02%.²² As shown on line 1,
13 page 8 of Schedule DWD-3, subtracting the mean monthly bond yield from the
14 total return on large company stocks results in a long-term historical equity risk
15 premium of 5.92%.

16 I used the arithmetic mean monthly total return rates for the large company
17 stocks and yields (income returns) for the Moody's Aaa/Aa corporate bonds,
18 because they are appropriate for the purpose of estimating the cost of capital as
19 noted in SBBI - 2021.²³ Using the arithmetic mean return rates and yields is
20 appropriate because historical total returns and equity risk premiums provide
21 insight into the variance and standard deviation of returns needed by investors in

²¹ SBBI Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2020.

²² As explained in note 1, page 9 of Schedule DWD-3.

²³ SBBI - 2021, at 10-22 and 10-23.

1 estimating future risk when making a current investment. If investors relied on the
2 geometric mean of historical equity risk premiums, they would have no insight into
3 the potential variance of future returns, because the geometric mean relates the
4 change over many periods to a constant rate of change, thereby obviating the year-
5 to-year fluctuations, or variance, which is critical to risk analysis.

6 **Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED**
7 **MARKET EQUITY RISK PREMIUM.**

8 A. To derive the regression-based market equity risk premium of 8.69% shown on line
9 2, page 8 of Schedule DWD-3, I used the same monthly annualized total returns on
10 large company common stocks relative to the monthly annualized yields on
11 Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the
12 relationship between interest rates and the market equity risk premium using the
13 observed monthly market equity risk premium as the dependent variable, and the
14 monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent
15 variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which
16 the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-
17 rated corporate bonds yield:

$$RP = \alpha + \beta (R_{Aaa/Aa})$$

19 **Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK**
20 **PREMIUM.**

21 A. I used the same PRPM approach described above to the PRPM equity risk premium.
22 The inputs to the model are the historical monthly returns on large company
23 common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate

bonds during the period from January 1928 through May 2021.²⁴ Using the previously discussed generalized form of ARCH, known as GARCH, the projected equity risk premium is determined using Eviews[®] statistical software. The resulting PRPM predicted a market equity risk premium of 9.02%.²⁵

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON VALUE LINE 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 9 of Schedule 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 May 28, 2021, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line's Standard Edition*.²⁶

The average median expected price appreciation is 28%, which translates to a 6.37% annual appreciation, and, when added to the average of *Value Line's* median expected dividend yields of 1.79%, equates to a forecasted annual total return rate on the market of 8.16%. The forecasted Moody's Aaa-rated corporate bond yield of 3.56% is deducted from the total market return of 8.16%, resulting in an equity risk premium of 4.60%, as shown on line 4, page 8 of Schedule DWD-3.

²⁴ Data from January 1928 to December 2020 is from SBBI - 2021. Data from January 2021 to May 2021 is from Bloomberg.

²⁵ Shown on line 3, page 8 of Schedule DWD-3.

²⁶ As explained in detail in note 1, page 2 of Schedule DWD-4.

1 **Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM**
2 **BASED ON THE S&P 500 COMPANIES.**

3 A. Using data from *Value Line*, I calculated an expected total return on the S&P 500
4 companies using expected dividend yields and long-term growth estimates as a
5 proxy for capital appreciation. The expected total return for the S&P 500 is 14.32%.
6 Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.56%
7 results in an 10.76% projected equity risk premium.

8 **Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM**
9 **BASED ON BLOOMBERG DATA.**

10 A. Using data from Bloomberg, I calculated an expected total return on the S&P 500
11 using expected dividend yields and long-term growth estimates as a proxy for
12 capital appreciation, identical to the method described above. The expected total
13 return for the S&P 500 is 16.34%. Subtracting the prospective yield on Moody's
14 Aaa-rated corporate bonds of 3.56% results in a 12.78% projected equity risk
15 premium.

16 **Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK**
17 **PREMIUM FOR USE IN YOUR RPM ANALYSIS?**

18 A. I gave equal weight to all six equity risk premiums based on each source - historical,
19 *Value Line*, and Bloomberg - in arriving at a 8.63% equity risk premium.

Table 4: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns²⁷

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2020)	5.92%
Regression Analysis on Historical Data	8.69%
PRPM Analysis on Historical Data	9.02%
Prospective Equity Risk Premium using Total Market Returns from <i>Value Line</i> Summary & Index less Projected Aaa Corporate Bond Yields	4.60%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from <i>Value Line</i> for the S&P 500 less Projected Aaa Corporate Bond Yields	10.76%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields	<u>12.78%</u>
Average	<u>8.63%</u>

After calculating the average market equity risk premium of 8.63%, I adjusted it by the beta coefficient to account for the risk of the Utility Proxy Group. As discussed below, the beta coefficient 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 Schedule DWD-4, the average of the mean and median beta coefficient for the Utility Proxy Group is 0.93. Multiplying the 0.93 average by the market equity risk premium of 8.63% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 8.03%.

²⁷ As shown on page 8 of Schedule 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 A-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. 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 10.65%, and monthly Moody's A-rated public utility bond yields of 6.49% from 1928 to 2020, to arrive at an equity risk premium of 4.16%.²⁸ I then used the same historical data to derive an equity risk premium of 6.37% 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 May 2021 to arrive at a PRPM-derived equity risk premium of 5.41% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 11.40% and 9.77% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 3.95%²⁹, which resulted in equity risk premiums of 7.45% and 5.82%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source

²⁸ As shown on line 1, page 12 of Schedule DWD-3.

²⁹ Derived on line 3, page 3 of Schedule DWD-3.

(i.e., historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 5.84%.

Table 5: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns³⁰

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2020)	4.16%
Regression Analysis on Historical Data	6.37%
PRPM Analysis on Historical Data	5.41%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from <i>Value Line</i> for the S&P Utilities Index less Projected A2 Utility Bond Yields	7.45%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields	<u>5.82%</u>
Average	<u><u>5.84%</u></u>

c. Authorized Return-Derived Equity Risk Premium

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 5.64% BASED ON AUTHORIZED ROES FOR GAS DISTRIBUTION UTILITIES?

A. The equity risk premium of 5.64% shown on line 3, page 7 of Schedule DWD-3 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A-rated public utility bonds. That analysis is shown on page 13 of Schedule DWD-3 which contains the graphical results of a regression analysis of 800 rate cases for gas distribution utilities which were fully litigated during the period from January 1, 1980 through May 28, 2021. It shows the implicit equity risk premium relative to the yields on A-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 A-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium

³⁰ As shown on page 12 of Schedule DWD-3.

1 rises and vice versa, a result consistent with financial literature on the subject.³¹ I
2 used the regression results to estimate the equity risk premium applicable to the
3 projected yield on Moody's A2-rated public utility bonds of 3.95%. Given the
4 expected A-rated utility bond yield of 3.95%, it can be calculated that the indicated
5 equity risk premium applicable to that bond yield is 5.64%, which is shown on line
6 3, page 7 of Schedule DWD-3.

7 **Q. WHAT IS YOUR CONCLUSION OF AN EQUITY RISK PREMIUM FOR**
8 **USE IN YOUR TOTAL MARKET APPROACH RPM ANALYSIS?**

9 A. The equity risk premium I apply to the Utility Proxy Group is 6.50%, which is the
10 average of the beta-adjusted equity risk premium for the Utility Proxy Group, the
11 S&P Utilities Index, and the authorized return utility equity risk premiums of
12 8.03%, 5.84%, and 5.64%, respectively.³²

13 **Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE**
14 **BASED ON THE TOTAL MARKET APPROACH?**

15 A. As shown on line 7, page 3 of Schedule DWD-3, I calculated a common equity cost
16 rate of 10.49% for the Utility Proxy Group based on the total market approach
17 RPM.

18 **Table 6: Summary of the Total Market Return Risk Premium Model³³**

Prospective Moody's A2/A3-Rated Utility Bond Applicable to the Utility Proxy Group	3.99%
Prospective Equity Risk Premium	6.50%
Indicated Cost of Common Equity	<u>10.49%</u>

³¹ 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 pages 11 to 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 pages 33 to 45.

³² As shown on page 7 of Schedule DWD-3.

³³ As shown on page 3 of Schedule DWD-3.

1 **Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE PRPM**
2 **AND THE TOTAL MARKET APPROACH RPM?**

3 A. As shown on page 1 of Schedule DWD-3, the indicated RPM-derived common
4 equity cost rate is 10.96%, which gives equal weight to the PRPM (11.43%) and
5 the adjusted-market approach results (10.49%).

6 **C. The Capital Asset Pricing Model**

7 **Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.**

8 A. CAPM theory defines risk as the co-variability of a security's returns with the
9 market's returns as measured by the beta coefficient (β). A beta coefficient less
10 than 1.0 indicates lower variability than the market as a whole, while a beta
11 coefficient greater than 1.0 indicates greater variability than the market.

12 The CAPM assumes that all non-market or unsystematic risk can be
13 eliminated through diversification. The risk that cannot be eliminated through
14 diversification is called market, or systematic, risk. In addition, the CAPM
15 presumes that investors only require compensation for systematic risk, which is the
16 result of macroeconomic and other events that affect the returns on all assets. The
17 model is applied by adding a risk-free rate of return to a market risk premium, which
18 is adjusted proportionately to reflect the systematic risk of the individual security
19 relative to the total market as measured by the beta coefficient. The traditional
20 CAPM model is expressed as:

21 $R_s = R_f + \beta (R_m - R_f)$

22 Where: R_s = Return rate on the common stock

23 R_f = Risk-free rate of return

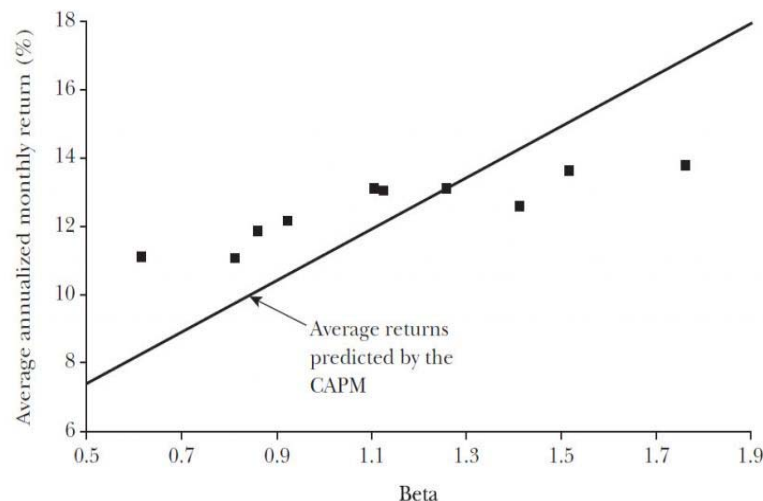
24 R_m = Return rate on the market as a whole

β = Adjusted beta coefficient (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 coefficients 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 coefficient 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.³⁴

The ECAPM reflects this empirical reality. Fama and 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."³⁵

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



³⁴ Roger A. Morin, *New Regulatory Finance* (Public Utility Reports, Inc., 2006), at 175. (Morin)
³⁵ 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).

1 In addition, Morin observes that while the results of these tests support the
2 notion that beta is related to security returns, the empirical SML described by the
3 CAPM formula is not as steeply sloped as the predicted SML. Morin states:

4 With few exceptions, the empirical studies agree that ... low-beta
5 securities earn returns somewhat higher than the CAPM would
6 predict, and high-beta securities earn less than predicted.³⁶

7 * * *

8 Therefore, the empirical evidence suggests that the expected return
9 on a security is related to its risk by the following approximation:

10
$$K = R_F + x \beta(R_M - R_F) + (1-x) \beta(R_M - R_F)$$

11 where x is a fraction to be determined empirically. The value of x
12 that best explains the observed relationship [is] $\text{Return} = 0.0829 +$
13 0.0520β is between 0.25 and 0.30. If $x = 0.25$, the equation
14 becomes:

15
$$K = R_F + 0.25(R_M - R_F) + 0.75 \beta(R_M - R_F)^{37}$$

16 Fama and French provide similar support for the ECAPM when they state:

17 The early tests firmly reject the Sharpe-Lintner version of the
18 CAPM. There is a positive relation between beta and average return,
19 but it is too 'flat'... The regressions consistently find that the
20 intercept is greater than the average risk-free rate... and the
21 coefficient on beta is less than the average excess market return...
22 This is true in the early tests... as well as in more recent cross-
23 section regressions tests, like Fama and French (1992).³⁸

24 Finally, Fama and French further note:

25 Confirming earlier evidence, the relation between beta and average
26 return for the ten portfolios is much flatter than the Sharpe-Linter
27 CAPM predicts. The returns on low beta portfolios are too high,
28 and the returns on the high beta portfolios are too low. For example,
29 the predicted return on the portfolio with the lowest beta is 8.3
30 percent per year; the actual return as 11.1 percent. The predicted
31 return on the portfolio with the t beta is 16.8 percent per year; the
32 actual is 13.7 percent.³⁹

³⁶ Morin, at 175.

³⁷ Morin, at 190.

³⁸ Fama & French, at 32.

³⁹ *Ibid.*, at 33.

1
2 Clearly, the justification from Morin, Fama, and French, along with their
3 reviews of other academic research on the CAPM, validate the use of the ECAPM.
4 In view of theory and practical research, I have applied both the traditional CAPM
5 and the ECAPM to the companies in the Utility Proxy Group and averaged the
6 results.

7 **Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM**
8 **ANALYSIS?**

9 A. For the beta coefficients in my CAPM analysis, I considered two sources: *Value*
10 *Line* and Bloomberg Professional Services. While both of those services adjust
11 their calculated (or “raw”) beta coefficients to reflect the tendency of the beta
12 coefficient to regress to the market mean of 1.00, *Value Line* calculates the beta
13 coefficient over a five-year period, while Bloomberg calculates it over a two-year
14 period.

15 **Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF**
16 **RETURN.**

17 A. As discussed previously, the risk-free rate adopted for both applications of the
18 CAPM is 2.88%. This risk-free rate is based on the average of the *Blue Chip*
19 consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the
20 six quarters ending with the third calendar quarter of 2022, and long-term
21 projections for the years 2023 to 2027 and 2028 to 2032.

1 **Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK**
2 **PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSES.**

3 A. The basis of the market risk premium is explained in detail in note 1 on Schedule
4 DWD-4. As discussed above, the market risk premium is derived from an average
5 of three historical data-based market risk premiums, two *Value Line* data-based
6 market risk premiums, and one Bloomberg data-based market risk premium.

7 The long-term income return on U.S. Government securities of 5.05% was
8 deducted from the SBBI - 2021 monthly historical total market return of 12.20%,
9 which results in an historical market equity risk premium of 7.15%.⁴⁰ I applied a
10 linear OLS regression to the monthly annualized historical returns on the S&P 500
11 relative to historical yields on long-term U.S. Government securities from SBBI -
12 2021. That regression analysis yielded a market equity risk premium of 9.39%.
13 The PRPM market equity risk premium is 10.04% and is derived using the PRPM
14 relative to the yields on long-term U.S. Treasury securities from January 1926
15 through May 2021.

16 The *Value Line*-derived forecasted total market equity risk premium is
17 derived by deducting the forecasted risk-free rate of 2.88%, discussed above, from
18 the *Value Line* projected total annual market return of 8.16%, resulting in a
19 forecasted total market equity risk premium of 5.28%. The S&P 500 projected
20 market equity risk premium using *Value Line* data is derived by subtracting the
21 projected risk-free rate of 2.88% from the projected total return of the S&P 500 of
22 14.32%. The resulting market equity risk premium is 11.44%.

⁴⁰ SBBI - 2021, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 2.88% from the projected total return of the S&P 500 of 16.34%. The resulting market equity risk premium is 13.46%. These six measures, when averaged, result in an average total market equity risk premium of 9.46%.

Table 7: Summary of the Calculation of the Market Risk Premium for Use in the CAPM⁴¹

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2020)	7.15%
Regression Analysis on Historical Data	9.39%
PRPM Analysis on Historical Data	10.04%
Prospective Equity Risk Premium using Total Market Returns from <i>Value Line</i> Summary & Index less Projected 30-Year Treasury Bond Yields	5.28%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from <i>Value Line</i> for the S&P 500 less Projected 30-Year Treasury Bond Yields	11.44%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields	<u>13.46%</u>
Average	<u>9.46%</u>

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 Schedule DWD-4, the mean result of my CAPM/ECAPM analyses is 11.81%, the median is 11.68%, and the average of the two is 11.75%. 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 11.75%.

⁴¹ As shown on page 2 of Schedule DWD-4.

1 **D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-**
2 **Price Regulated Companies Based on the DCF, RPM, and CAPM**

3 **Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC,**
4 **NON-PRICE REGULATED COMPANIES?**

5 A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that
6 comparable risk companies had to be utilities. Since the purpose of rate regulation
7 is to be a substitute for marketplace competition, non-price regulated firms
8 operating in the competitive marketplace make an excellent proxy group if they are
9 comparable in total risk to the Utility Proxy Group being used to estimate the cost
10 of common equity. The selection of such domestic, non-price regulated competitive
11 firms theoretically and empirically results in a proxy group which is comparable in
12 total risk to the Utility Proxy Group, since all of these companies compete for
13 capital in the exact same markets.

14 **Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT**
15 **ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY**
16 **GROUP?**

17 A. In order to select a proxy group of domestic, non-price regulated companies similar
18 in total risk to the Utility Proxy Group, I relied on the beta coefficients and related
19 statistics derived from *Value Line* regression analyses of weekly market prices over
20 the most recent 260 weeks (*i.e.*, five years). These selection criteria resulted in a
21 proxy group of 48 domestic, non-price regulated firms comparable in total risk to
22 the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and
23 diversifiable company-specific risks. The criteria used in selecting the domestic,
24 non-price regulated firms was:

- 1 (i) They must be covered by *Value Line Investment Survey* (Standard
2 Edition);
- 3 (ii) They must be domestic, non-price regulated companies, *i.e.*, not utilities;
- 4 (iii) Their beta coefficients must lie within plus or minus two standard deviations
5 of the average unadjusted beta coefficients of the Utility Proxy Group; and
- 6 (iv) The residual standard errors of the *Value Line* regressions which gave rise
7 to the unadjusted beta coefficients must lie within plus or minus two
8 standard deviations of the average residual standard error of the Utility
9 Proxy Group.

10 Beta coefficients measure market, or systematic, risk, which is not
11 diversifiable. The residual standard errors of the regressions measure each firm's
12 company-specific, diversifiable risk. Companies that have similar beta coefficients
13 and similar residual standard errors resulting from the same regression analyses
14 have similar total investment risk.

15 **Q. HAVE YOU PREPARED AN SCHEDULE WHICH SHOWS THE DATA**
16 **FROM WHICH YOU SELECTED THE 48 DOMESTIC, NON-PRICE**
17 **REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK**
18 **TO THE UTILITY PROXY GROUP?**

19 A. Yes, the basis of my selection and both proxy groups' regression statistics are shown
20 in Schedule DWD-5.

21 **Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE**
22 **DCF MODEL, RPM, AND CAPM FOR THE NON-PRICE REGULATED**
23 **PROXY GROUP?**

24 A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical
25 manner as described above, I will not repeat the details of the rationale and

1 application of each model. One exception is in the application of the RPM, where
2 I did not use public utility-specific equity risk premiums, nor did I apply the PRPM
3 to the individual non-price regulated companies.

4 Page 2 of Schedule DWD-6 derives the constant growth DCF model
5 common equity cost rate. As shown, the indicated common equity cost rate, using
6 the constant growth DCF for the Non-Price Regulated Proxy Group comparable in
7 total risk to the Utility Proxy Group, is 12.83%.

8 Pages 3 through 5 of Schedule DWD-6 contain the data and calculations
9 that support the 12.49% RPM common equity cost rate. As shown on line 1, page
10 3 of Schedule DWD-6, the consensus prospective yield on Moody's Baa-rated
11 corporate bonds for the six quarters ending in the third quarter of 2022, and for the
12 years 2023 to 2027 and 2028 to 2032, is 4.46%.⁴²

13 When the beta-adjusted risk premium of 8.03%⁴³ relative to the Non-Price
14 Regulated Proxy Group is added to the prospective Baa2-rated corporate bond yield
15 of 4.46%, the indicated RPM common equity cost rate is 12.49%.

16 Page 6 of Schedule DWD-6 contains the inputs and calculations that support
17 my indicated CAPM/ECAPM common equity cost rate of 11.69%.

18 **Q. HOW IS THE COST RATE OF COMMON EQUITY BASED ON THE NON-**
19 **PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK**
20 **TO THE UTILITY PROXY GROUP?**

21 A. As shown on page 1 of Schedule DWD-6, the results of the common equity models
22 applied to the Non-Price Regulated Proxy Group -- which group is comparable in

⁴² *Blue Chip Financial Forecasts*, June 1, 2021, at page 2 and 14.

⁴³ Derived on page 5 of Schedule DWD-6.

1 total risk to the Utility Proxy Group -- are as follows: 12.83% (DCF), 12.49%
2 (RPM), and 11.69% (CAPM). The average of the mean and median of these models
3 is 12.42%, which I used as the indicated common equity cost rates for the Non-
4 Price Regulated Proxy Group.

5 **VI. CONCLUSION OF COMMON EQUITY COST RATE BEFORE**
6 **ADJUSTMENTS**

7 **Q. WHAT ARE THE INDICATED COMMON EQUITY COST RATES**
8 **BEFORE ADJUSTMENTS?**

9 A. By applying multiple cost of common equity models to the Utility Proxy Group and
10 the Non-Price Regulated Proxy Group, the indicated range of common equity cost
11 rates before any relative risk adjustment is between 9.44% and 12.42%. The spread
12 between the high and low values in the range (298 basis points) indicates that there
13 is still a fair amount of uncertainty around the recovery from the COVID-19
14 pandemic. I used multiple cost of common equity models as primary tools in
15 arriving at my recommended common equity cost rate, because no single model is
16 so inherently precise that it can be relied on to the exclusion of other theoretically
17 sound models. Using multiple models adds reliability to the estimated common
18 equity cost rate, with the prudence of using multiple cost of common equity models
19 supported in both the financial literature and regulatory precedent.

VII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

A. Size Adjustment

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.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Duff & Phelps 2020 Valuation Handbook Guide to Cost of Capital - Market Results through 2019 (D&P - 2020) 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," D&P - 2020 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

1 size has been shown to be a *predictor* of equity returns. In other
2 words, there is a significant (negative) relationship between size and
3 historical equity returns - as size *decreases*, returns tend to *increase*,
4 and vice versa. (footnote omitted) (emphasis in original)⁴⁴

5 Furthermore, in “The Capital Asset Pricing Model: Theory and Evidence,”
6 Fama and French note size is indeed a risk factor which must be reflected when
7 estimating the cost of common equity. On page 14, they note:

8 . . . the higher average returns on small stocks and high book-to-
9 market stocks reflect unidentified state variables that produce
10 undiversifiable risks (covariances) in returns not captured in the
11 market return and are priced separately from market betas.⁴⁵

12 Based on this evidence, Fama and French proposed their three-factor model
13 which includes a size variable in recognition of the effect size has on the cost of
14 common equity.

15 Also, it is a basic financial principle that the use of funds invested, and not
16 the source of funds, is what gives rise to the risk of any investment.⁴⁶ Eugene
17 Brigham, a well-known authority, states:

18 A number of researchers have observed that portfolios of small-
19 firms (sic) have earned consistently higher average returns than
20 those of large-firm stocks; this is called the “small-firm effect.” On
21 the surface, it would seem to be advantageous to the small firms to
22 provide average returns in a stock market that are higher than those
23 of larger firms. In reality, it is bad news for the small firm; **what the**
24 **small-firm effect means is that the capital market demands**
25 **higher returns on stocks of small firms than on otherwise similar**
26 **stocks of the large firms.** (emphasis added)⁴⁷

⁴⁴ Duff & Phelps Valuation Handbook – U.S. Guide to Cost of Capital, Wiley 2020, at 4-1.

⁴⁵ 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.

⁴⁶ Brealey, Richard A. and Myers, Stewart C., Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

⁴⁷ Brigham, Eugene F., Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

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.

Table 8: Size as Measured by Market Capitalization for Atmos Energy and the Utility Proxy Group

	<u>Market Capitalization*</u> (\$ Millions)	<u>Times Greater than The Company</u>
Atmos Energy	\$597.101	
Utility Proxy Group	\$4,615.314	7.7x
*From page 1 of Schedule DWD-7.		

Atmos Energy's estimated market capitalization was \$597.101 million as of May 28, 2021,⁴⁸ compared with the market capitalization of the average company

⁴⁸ \$597.101 (company-provided forecasted rate base at Twelve Months Ended December 31, 2022) * requested equity ratio of 57.05% * 175.6% (market-to-book ratio of the Utility Proxy Group) as demonstrated on page 2 of Schedule DWD-7.

1 in the Utility Proxy Group of \$4.6 billion as of May 28, 2021. The average
2 company in the Utility Proxy Group has a market capitalization 7.7 times the size
3 of Atmos Energy's estimated market capitalization.

4 As a result, it is necessary to upwardly adjust the range of indicated common
5 equity cost rates between 9.44% to 12.42% to reflect Atmos Energy's greater risk
6 due to their smaller relative size. The determination is based on the size premiums
7 for portfolios of New York Stock Exchange, American Stock Exchange, and
8 NASDAQ listed companies ranked by deciles for the 1926 to 2020 period. The
9 average size premium for the Utility Proxy Group with a market capitalization of
10 \$4.6 billion falls in the 4th decile, while the Company's estimated market
11 capitalization of \$597.101 million places it in the 8th decile. The size premium
12 spread between the 4th decile and the 8th decile is 0.71%. Even though a 0.71%
13 upward size adjustment is indicated, I applied a size premium of 0.20% to the
14 Company's range of indicated common equity cost rates.

15 **Q. SINCE ATMOS ENERGY IS A DIVISION OF ATO, WHY IS THE SIZE OF**
16 **THE TOTAL COMPANY NOT MORE APPROPRIATE TO USE WHEN**
17 **DETERMINING THE SIZE ADJUSTMENT?**

18 A. As discussed previously, rates are set using the stand-alone principle, which
19 maintains that the utility operations of a diversified firm should be regulated as
20 though they were independent (*i.e.*, without subsidies to or from affiliated
21 companies). Because of this, the return derived in this proceeding will not apply to
22 ATO as a whole, but only Atmos Energy's Kentucky gas distribution operations.
23 ATO is the sum of its constituent parts, including those constituent parts' ROEs.

Potential investors in the Company are aware that it is a combination of operations in each state, and that each state's operations experience the operating risks specific to their jurisdiction. The market's expectation of ATO's return is commensurate with the realities of its composite operations in each of the states in which it operates.

B. Credit Risk Adjustment

Q. PLEASE DISCUSS YOUR PROPOSED CREDIT RISK ADJUSTMENT.

ATO's long-term issuer ratings are A1 and A from Moody's Investors Services and S&P, respectively, which are less risky than the average long-term issuer ratings for the Utility Proxy Group of A2/A3 and A-, respectively.⁴⁹ Hence, a downward credit risk adjustment is necessary to reflect the less risky credit rating, *i.e.*, A1, of Atmos Energy relative to the A2/A3 average Moody's bond rating of the Utility Proxy Group.⁵⁰

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 and one-sixth of a recent spread between A- and Baa-rated public utility bonds, shown on page 4 of Schedule DWD-3, or 0.10%.⁵¹

⁴⁹ Source of Information: S&P Global Market Intelligence.

⁵⁰ As shown on page 5 of Schedule DWD-3.

⁵¹ $1/3 * 0.17\% = 0.06\% + 1/6 * 0.26\% = 0.04\%.$ $0.06\% + 0.04\% = 0.10\%.$

1 **C. Flotation Cost Adjustment**

2 **Q. WHAT ARE FLOTATION COSTS?**

3 A. Flotation costs are those costs associated with the sale of new issuances of common
4 stock. They include market pressure and the mandatory unavoidable costs of
5 issuance (*e.g.*, underwriting fees and out-of-pocket costs for printing, legal,
6 registration, etc.). For every dollar raised through debt or equity offerings, the
7 Company receives less than one full dollar in financing.

8 **Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE**
9 **ALLOWED COMMON EQUITY COST RATE?**

10 A. It is important because there is no other mechanism in the ratemaking paradigm
11 through which such costs can be recognized and recovered. Because these costs
12 are real, necessary, and legitimate, recovery of these costs should be permitted. As
13 noted by Morin:

14 The costs of issuing these securities are just as real as operating and
15 maintenance expenses or costs incurred to build utility plants, and
16 fair regulatory treatment must permit recovery of these costs....

17 The simple fact of the matter is that common equity capital is not
18 free....[Flotation costs] must be recovered through a rate of return
19 adjustment.⁵²

20 **Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS**
21 **AN ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT**
22 **POST-TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?**

23 A. No. As noted above, there is no mechanism to recapture such costs in the
24 ratemaking paradigm other than an adjustment to the allowed common equity cost

⁵² Morin, at p. 321.

1 rate. Flotation costs are charged to capital accounts and are not expensed on a
2 utility's income statement. As such, flotation costs are analogous to capital
3 investments, albeit negative, reflected on the balance sheet. Recovery of capital
4 investments relates to the expected useful lives of the investment. Since common
5 equity has a very long and indefinite life (assumed to be infinity in the standard
6 regulatory DCF model), flotation costs should be recovered through an adjustment
7 to common equity cost rate, even when there has not been an issuance during the
8 test year, or in the absence of an expected imminent issuance of additional shares
9 of common stock.

10 Historical flotation costs are a permanent loss of investment to the utility
11 and should be accounted for. When any company, including a utility, issues
12 common stock, flotation costs are incurred for legal, accounting, printing fees and
13 the like. For each dollar of issuing market price, a small percentage is expensed
14 and is permanently unavailable for investment in utility rate base. Since these
15 expenses are charged to capital accounts and not expensed on the income statement,
16 the only way to restore the full value of that dollar of issuing price with an assumed
17 investor required return of 10% is for the net investment, \$0.95, to earn more than
18 10% to net back to the investor a fair return on that dollar. In other words, if a
19 company issues stock at \$1.00 with 5% in flotation costs, it will net \$0.95 in
20 investment. Assuming the investor in that stock requires a 10% return on his or her

1 invested \$1.00 (*i.e.*, a return of \$0.10), the company needs to earn approximately
2 10.5% on its invested \$0.95 to receive a \$0.10 return.

3 **Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED**
4 **ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION**
5 **COSTS?**

6 A. No. All of these models assume no transaction costs. The literature is quite clear
7 that these costs are not reflected in the market prices paid for common stocks. For
8 example, Brigham and Daves confirm this and provide the methodology utilized to
9 calculate the flotation adjustment.⁵³ In addition, Morin confirms the need for such
10 an adjustment even when no new equity issuance is imminent.⁵⁴ Consequently, it
11 is proper to include a flotation cost adjustment when using cost of common equity
12 models to estimate the common equity cost rate.

13 **Q. HOW DID YOU CALCULATE THE FLOTATION COST ALLOWANCE?**

14 A. I modified the DCF calculation to provide a dividend yield that would reimburse
15 investors for issuance costs in accordance with the method cited in literature by
16 Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes
17 the actual costs of issuing equity that were incurred by ATO in its last four equity
18 issuances. Based on the issuance costs shown on page 1 of Schedule DWD-8, an
19 adjustment of 0.04% is required to reflect the flotation costs applicable to the Utility
20 Proxy Group.

⁵³ Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition,
Thomson/Southwestern, at p. 342.

⁵⁴ Morin, at pp. 327-30.

VIII. CONCLUSION

1

2 **Q. WHAT IS YOUR RECOMMENDED ROE FOR ATMOS ENERGY?**

3 A. Given the indicated ROE range applicable to the Utility Proxy Group of 9.44% to
4 12.42% and the Company-specific ROE range of 9.58% to 12.42%, I conclude that
5 an appropriate ROE for the Company is 10.35%.

6 **Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.35% FAIR AND**
7 **REASONABLE TO ATMOS ENERGY AND ITS CUSTOMERS?**

8 A. Yes, it is.

9 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

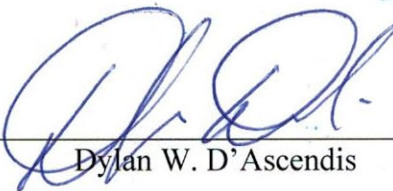
10 A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF)
RATE APPLICATION OF) Case No. 2021-00214
ATMOS ENERGY CORPORATION)

CERTIFICATE AND AFFIDAVIT

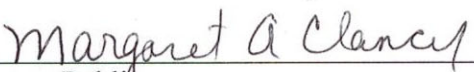
The Affiant, Dylan W. D'Ascendis, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2021-00214, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked 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 14th
day of June, 2021.

Margaret A Clancy
Notary Public of New Jersey
My Commission Expires 6/9/2024


Notary Public
My Commission Expires: 6/9/2024

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). He has served as a consultant for investor-owned and municipal utilities and authorities for 12 years. Dylan has extensive experience in rate of return analyses, class cost of service, rate design, and valuation for regulated public utilities. He has testified as an expert witness in the subjects of rate of return, cost of service, rate design, and valuation before 30 regulatory commissions in the U.S., one Canadian province, and an American Arbitration Association panel.

He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured.

Areas of Specialization

- Regulation and Rates
- Utilities
- Mutual Fund Benchmarking
- Capital Market Risk
- Financial Modeling
- Valuation
- Regulatory Strategy
- Rate Case Support
- Rate of Return
- Cost of Service
- Rate Design

Recent Expert Testimony Submission/Apearances

<i>Jurisdiction</i>	<i>Topic</i>
■ Massachusetts Department of Public Utilities	Rate of Return
■ New Jersey Board of Public Utilities	Rate of Return
■ Hawaii Public Utilities Commission	Cost of Service, Rate Design
■ South Carolina Public Service Commission	Return on Common Equity
■ American Arbitration Association	Valuation

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 company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Publications and Speeches

- Co-Author of: "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.
- Co-Author of: "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", 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.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, 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", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN.

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
Regulatory Commission of Alaska				
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.	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.	06/20	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				
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
Colorado Public Utilities Commission				
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
Delaware Public Service Commission				
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	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	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System	09/20	Peoples Gas System	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

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
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	07/19	Atmos Energy	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
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				
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy	04/20	Atmos Energy	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
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	Docket No. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Rate of Return
Mississippi Public Service Commission				
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Docket No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
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				
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	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				
Southwestern Public Service Company	01/21	Southwestern Public Service Company	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
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	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Docket No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
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
Tennessee Public Utility Commission				
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 Company	02/21	Southwestern Public Service Company	Docket No. 51802	Return on Equity
Southwestern Electric Power Company	10/20	Southwestern Electric Power Company	Docket No. 51415	Rate of Return
Virginia State Corporation Commission				
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

Atmos Energy Corporation
 Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

<u>Type Of Capital</u>	<u>Ratios (1)</u>	<u>Cost Rate</u>	<u>Weighted Cost Rate</u>
Long-Term Debt	42.77%	4.00% (1)	1.71%
Short-Term Debt	0.18%	25.17% (1)	0.05%
Common Equity	<u>57.05%</u>	10.35% (2)	<u>5.90%</u>
Total	<u><u>100.00%</u></u>		<u><u>7.66%</u></u>

Notes:

(1) Company-provided.

(2) From page 2 of this Schedule.

Atmos Energy Corporation
Brief Summary of Common Equity Cost Rate

<u>Line No.</u>	<u>Principal Methods</u>	<u>Proxy Group of Seven Natural Gas Distribution Companies</u>
1.	Discounted Cash Flow Model (DCF) (1)	9.44%
2.	Risk Premium Model (RPM) (2)	10.96%
3.	Capital Asset Pricing Model (CAPM) (3)	11.75%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	<u>12.42%</u>
5.	Range of Common Equity Model Results	9.44% - 12.42%
6.	Size Risk Adjustment (5)	0.20%
7.	Credit Risk Adjustment (6)	-0.10%
8.	Flotation Cost Adjustment (7)	<u>0.04%</u>
9.	Indicated Range of Common Equity Cost Rates after Adjustment	<u><u>9.58% - 12.66%</u></u>
10.	Recommended Common Equity Cost Rate	<u><u>10.35%</u></u>

- 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 due to its smaller size relative to the Utility Proxy Group as detailed in Mr. D'Ascendis' direct testimony.
 - (6) Company-specific risk adjustment to reflect Atmos Energy's lower risk due to a higher long-term issuer rating relative to the proxy group as detailed in Mr. D'Ascendis' direct testimony.
 - (7) From page 1 of Schedule DWD-8.

Atmos Energy Corporation
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seven 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	Bloomberg's Five Year Projected Growth Rate in EPS	Yahoo! Finance 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	2.54 %	7.00 %	7.30 %	7.10 %	7.17 %	7.14 %	2.63 %	9.77 %
New Jersey Resources Corporation	3.19	2.00	7.10	7.33	6.00	5.61	3.28	8.89
Northwest Natural Holding Company	3.57	5.50	3.90	4.42	3.80	4.41	3.65	8.06
ONE Gas, Inc.	3.02	6.50	5.00	5.67	5.00	5.54	3.10	8.64
South Jersey Industries, Inc.	4.84	11.50	5.40	4.93	4.80	6.66	5.00	11.66
Southwest Gas Holdings, Inc.	3.45	9.00	5.50	4.50	4.00	5.75	3.55	9.30
Spire Inc.	3.49	10.00	5.50	5.33	7.31	7.04	3.61	10.65
							Average	<u>9.57 %</u>
							Median	<u>9.30 %</u>
							Average of Mean and Median	<u>9.44 %</u>

NA= Not Available
NMF= Not Meaningful Figure

Notes:

- (1) Indicated dividend at 05/28/2021 divided by the average closing price of the last 60 trading days ending 05/28/2021 for each company.
- (2) From pages 2 through 8 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, $2.54\% \times (1 + (1/2 \times 7.14\%)) = 2.63\%$.
- (5) Column 6 + column 7.

Source of Information:

Value Line Investment Survey
www.zacks.com Downloaded on 05/28/2021
www.yahoo.com Downloaded on 05/28/2021
Bloomberg Professional Services

Atmos Energy Corporation
Summary of Risk Premium Models for the
Proxy Group of Seven Natural Gas Distribution Companies

	<u>Proxy Group of Seven Natural Gas Distribution Companies</u>
Predictive Risk Premium Model (PRPM) (1)	11.43 %
Risk Premium Using an Adjusted Total Market Approach (2)	<u>10.49 %</u>
Average	<u><u>10.96 %</u></u>

Notes:

(1) From page 2 of this Schedule.

(2) From page 3 of this Schedule.

Atmos Energy Corporation
Indicated ROE
Derived by the Predictive Risk Premium Model (1)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Seven Natural Gas Distribution Companies	LT Average Predicted Variance	Spot Predicted Variance	Recommended Variance (2)	GARCH Coefficient	Predicted Risk Premium (3)	Risk-Free Rate (4)	Indicated ROE (5)
Atmos Energy Corporation	0.33%	0.48%	0.41%	2.2565	11.58%	2.88%	14.46%
New Jersey Resources Corporation	0.38%	0.34%	0.36%	2.0814	9.43%	2.88%	12.31%
Northwest Natural Holding Company	0.32%	0.38%	0.35%	1.5413	6.68%	2.88%	9.56%
ONE Gas, Inc.	0.30%	0.43%	0.37%	4.0633	19.39%	2.88%	NMF
South Jersey Industries, Inc.	0.39%	0.69%	0.54%	1.6346	11.03%	2.88%	13.91%
Southwest Gas Holdings, Inc.	0.43%	0.38%	0.41%	1.3628	6.84%	2.88%	9.72%
Spire Inc.	0.71%	0.52%	0.61%	0.9445	7.18%	2.88%	10.06%
						Average	<u>11.67%</u>
						Median	<u>11.19%</u>
					Average of Mean and Median		<u>11.43%</u>

Notes:

- (1) The Predictive Risk Premium Model uses historical data to generate a predicted variance and a GARCH coefficient. The historical data used are the equity risk premiums for the first available trading month as reported by Bloomberg Professional Service.
- (2) Given current market conditions, I recommend using average of the the long-term average predicted variance and the spot variance.
- (3) $(1 + (\text{Column [3]} * \text{Column [4]})^{12}) - 1$.
- (4) From note 2 on page 2 of Schedule DWD-4.
- (5) Column [5] + Column [6].

Atmos Energy Corporation
 Indicated Common Equity Cost Rate
 Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

<u>Line No.</u>		<u>Proxy Group of Seven Natural Gas Distribution Companies</u>
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	3.56 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds	<u>0.39 (2)</u>
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	3.95 %
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group	<u>0.04 (3)</u>
5.	Adjusted Prospective Bond Yield	3.99 %
6.	Equity Risk Premium (4)	<u>6.50</u>
7.	Risk Premium Derived Common Equity Cost Rate	<u><u>10.49 %</u></u>

- Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 10 and 11 of this Schedule).
- (2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.39% from page 4 of this Schedule.
- (3) Adjustment to reflect the A2/A3 Moody's LT issuer rating of the Utility Proxy Group as shown on page 5 of this Schedule. The 0.04% upward adjustment is derived by taking 1/6 of the spread between A2 and Baa2 Public Utility Bonds ($1/6 * 0.26\% = 0.04\%$) as derived from page 4 of this Schedule.
- (4) From page 7 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]	[2]	[3]	[4]
	<u>Aaa Rated Corporate Bond</u>	<u>Aa2 Rated Public Utility Bond</u>	<u>A2 Rated Public Utility Bond</u>	<u>Baa2 Rated Public Utility Bond</u>
May-2021	2.96 %	3.17 %	3.33 %	3.58 %
Apr-2021	2.90	3.13	3.30	3.57
Mar-2021	<u>3.04</u>	<u>3.27</u>	<u>3.44</u>	<u>3.72</u>
Average	<u><u>2.97 %</u></u>	<u><u>3.19 %</u></u>	<u><u>3.36 %</u></u>	<u><u>3.62 %</u></u>

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:

0.39 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:

0.26 % (2)

A2 Rated Public Utility Bonds Over Aa2 Rated Public Utility Bonds:

0.17 % (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 Seven Natural Gas Distribution Companies

	Moody's		Standard & Poor's	
	Long-Term Issuer Rating		Long-Term Issuer Rating	
	May 2021		May 2021	
<u>Proxy Group of Seven Natural Gas Distribution Companies</u>	<u>Long-Term Issuer Rating (1)</u>	<u>Numerical Weighting (2)</u>	<u>Long-Term Issuer Rating (1)</u>	<u>Numerical Weighting (2)</u>
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	BBB+	8.0
South Jersey Industries, Inc.	A3	7.0	BBB	9.0
Southwest Gas Holdings, Inc.	Baa1	8.0	A-	7.0
Spire Inc.	A1/A2	5.5	A-	7.0
Average	<u>A2/A3</u>	<u>6.5</u>	<u>A-</u>	<u>7.2</u>

Notes:

(1)

Ratings are that of the average of each company's utility operating subsidiaries.

(2) From page 6 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 Seven Natural Gas Distribution Companies

<u>Line No.</u>		<u>Proxy Group of Seven Natural Gas Distribution Companies</u>
1.	Calculated equity risk premium based on the total market using the beta approach (1)	8.03 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	5.84
3.	Predicted Equity Risk Premium Based on Regression Analysis of 800 Fully-Litigated Natural Gas Utility Rate Cases	<u>5.64</u>
4.	Average equity risk premium	<u><u>6.50 %</u></u>

Notes: (1) From page 8 of this Schedule.
 (2) From page 12 of this Schedule.
 (3) From page 13 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 Seven Natural Gas Distribution Companies

<u>Line No.</u>	<u>Equity Risk Premium Measure</u>	<u>Proxy Group of Seven Natural Gas Distribution Companies</u>
<u>Ibbotson-Based Equity Risk Premiums:</u>		
1.	Ibbotson Equity Risk Premium (1)	5.92 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.69
3.	Ibbotson Equity Risk Premium based on PRPM (3)	9.02
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	4.60
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.76
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	<u>12.78</u>
7.	Conclusion of Equity Risk Premium	8.63 %
8.	Adjusted Beta (7)	<u>0.93</u>
9.	Forecasted Equity Risk Premium	<u><u>8.03</u></u> %

Notes provided on page 9 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 Seven Natural Gas Distribution Companies

Notes:

- (1) Based on the arithmetic mean historical monthly returns on large company common stocks from Duff & Phelps 2021 SBBI® Yearbook minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1928-2020.
- (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 Aa rated corporate bond yields from 1928-2020 referenced in Note 1 above.
- (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 March 2021.
- (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 3.56% (from page 3 of this Schedule) from the projected 3-5 year total annual market return of 8.16% (described fully in note 1 on page 2 of Schedule DWD-4).
- (5) Using data from Value Line for the S&P 500, an expected total return of 14.32% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.56% results in an expected equity risk premium of 10.76%.
- (6) Using data from the Bloomberg Professional Service for the S&P 500, an expected total return of 16.34% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.56% results in an expected equity risk premium of 12.78%.
- (7) Average of mean and median beta from Schedule DWD-4.

Sources of Information:

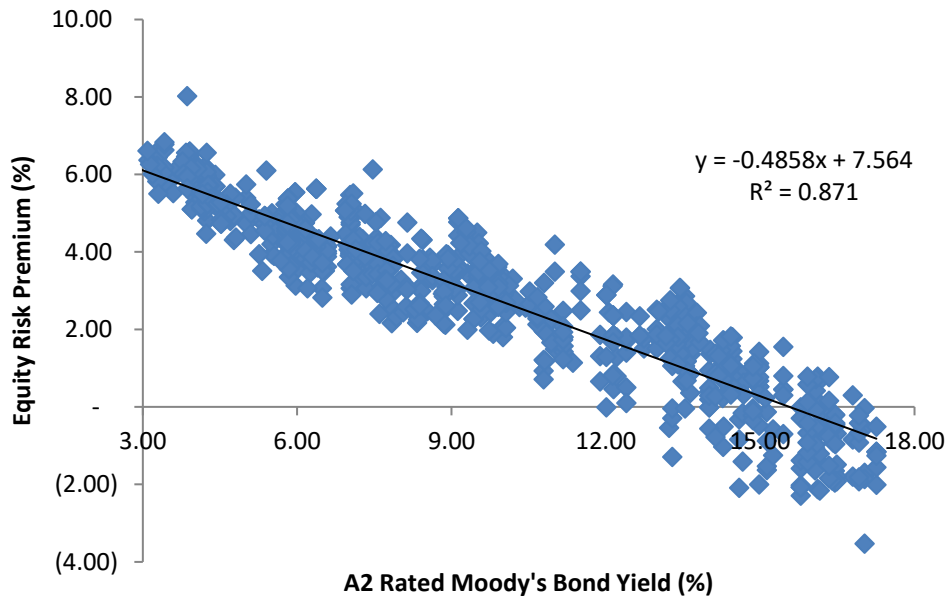
Stocks, Bonds, Bills, and Inflation - 2021 SBBI Yearbook, John Wiley & Sons, Inc.
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, June 1, 2021
Bloomberg Professional Service

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

<u>Line No.</u>		<u>Implied Equity Risk Premium</u>
	<u>Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):</u>	
1.	Historical Equity Risk Premium	4.16 %
2.	Regression of Historical Equity Risk Premium (2)	6.37
3.	Forecasted Equity Risk Premium Based on PRPM (3)	5.41
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	7.45
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	<u>5.82</u>
6.	Average Equity Risk Premium (6)	<u><u>5.84 %</u></u>

- Notes: (1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2020. 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 - 2020 referenced in note 1 above.
- (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 - May 2021.
- (4) Using data from Value Line for the S&P Utilities Index, an expected return of 11.40% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 3.95%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 7.45%. (11.40% - 3.95% = 7.45%)
- (5) Using data from Bloomberg Professional Service for the S&P Utilities Index, an expected return of 9.77% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 3.95%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 5.82%. (9.77% - 3.95% = 5.82%)
- (6) Average of lines 1 through 5.

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
7.564001 %	-0.48585	3.95 %	5.64 %

Notes:

(1) From line 3 of page 3 of this Schedule.

Source of Information:

Regulatory Research Associates
 Bloomberg Professional Services

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)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seven Natural Gas Distribution Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.80	0.91	0.86	9.46 %	2.88 %	11.02 %	11.35 %	11.18 %
New Jersey Resources Corporation	1.00	0.97	0.98	9.46	2.88	12.15	12.20	12.17
Northwest Natural Holding Company	0.85	0.85	0.85	9.46	2.88	10.92	11.28	11.10
ONE Gas, Inc.	0.80	1.00	0.90	9.46	2.88	11.39	11.63	11.51
South Jersey Industries, Inc.	1.05	0.98	1.02	9.46	2.88	12.53	12.48	12.51
Southwest Gas Holdings, Inc.	0.95	1.09	1.02	9.46	2.88	12.53	12.48	12.51
Spire Inc.	0.85	1.00	0.92	9.46	2.88	11.58	11.77	11.68
Mean			0.94			11.73 %	11.88 %	11.81 %
Median			0.92			11.58 %	11.77 %	11.68 %
Average of Mean and Median			0.93			11.66 %	11.83 %	11.75 %

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:

Historical Data MRP Estimates:

Measure 1: Ibbotson Arithmetic Mean MRP (1926-2020)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2020:	12.20 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.05
MRP based on Ibbotson Historical Data:	<u>7.15 %</u>

Measure 2: Application of a Regression Analysis to Ibbotson Historical Data (1926-2020)

9.39 %

Measure 3: Application of the PRPM to Ibbotson Historical Data: (January 1926 - May 2021)

10.04 %

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending May 28, 2021)

Total projected return on the market 3-5 years hence*:	8.16 %
Projected Risk-Free Rate (see note 2):	2.88
MRP based on Value Line Summary & Index:	<u>5.28 %</u>
*Forecasted 3-5 year capital appreciation plus expected dividend yield	

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	14.32 %
Projected Risk-Free Rate (see note 2):	2.88
MRP based on Value Line data	<u>11.44 %</u>

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	16.34 %
Projected Risk-Free Rate (see note 2):	2.88
MRP based on Bloomberg data	<u>13.46 %</u>

Average of Value Line, Ibbotson, and Bloomberg MRP: 9.46 %

- (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 10 and 11 of Schedule DWD-3.) The projection of the risk-free rate is illustrated below:

Second Quarter 2021	2.40 %
Third Quarter 2021	2.50
Fourth Quarter 2021	2.60
First Quarter 2022	2.60
Second Quarter 2022	2.70
Third Quarter 2022	2.80
2023-2027	3.50
2028-2032	3.90
	<u>2.88 %</u>

- (3) Average of Column 6 and Column 7.

Sources of Information:

Value Line Summary and Index
 Blue Chip Financial Forecasts, June 1, 2021
 Stocks, Bonds, Bills, and Inflation - 2021 SBBI Yearbook, John Wiley & Sons, Inc.
 Bloomberg Professional Services

Atmos Energy Corporation
 Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

	[1]	[2]	[3]	[4]
<u>Proxy Group of Seven Natural Gas Distribution Companies</u>	<u>Value Line Adjusted Beta</u>	<u>Unadjusted Beta</u>	<u>Residual Standard Error of the Regression</u>	<u>Standard Deviation of Beta</u>
Atmos Energy Corporation	0.80	0.66	2.7453	0.0685
New Jersey Resources Corporation	0.95	0.92	3.0205	0.0754
Northwest Natural Holding Company	0.80	0.69	3.1454	0.0785
ONE Gas, Inc.	0.80	0.67	2.7077	0.0676
South Jersey Industries, Inc.	1.05	1.00	3.4767	0.0868
Southwest Gas Holdings, Inc.	0.95	0.88	3.0244	0.0755
Spire Inc.	0.85	0.71	2.8287	0.0706
Average	<u>0.89</u>	<u>0.79</u>	<u>2.9927</u>	<u>0.0747</u>
Beta Range (+/- 2 std. Devs. of Beta)	0.64	0.94		
2 std. Devs. of Beta	0.15			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.7297	3.2557		
Std. dev. of the Res. Std. Err.	0.1315			
2 std. devs. of the Res. Std. Err.	0.2630			

Source of Information: Valueline Proprietary Database, March 2021

Atmos Energy Corporation
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]
Proxy Group of Forty-Eight Non-Price Regulated Companies	VL Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Apple Inc.	0.90	0.81	3.1746	0.0792
Abbott Labs.	0.95	0.88	2.7401	0.0684
Assurant Inc.	0.90	0.84	2.9537	0.0737
ANSYS, Inc.	0.85	0.74	2.8841	0.0720
Booz Allen Hamilton	0.90	0.82	3.0468	0.0760
Becton, Dickinson	0.80	0.66	2.8952	0.0722
Brown-Forman 'B'	0.90	0.77	2.7453	0.0685
Broadridge Fin'l	0.85	0.70	2.7332	0.0682
Brady Corp.	1.00	0.93	3.0007	0.0749
CACI Int'l	0.95	0.86	3.1684	0.0791
Casey's Gen'l Stores	0.90	0.78	3.2522	0.0812
Cadence Design Sys.	0.90	0.79	3.0338	0.0757
Cerner Corp.	0.90	0.84	2.7309	0.0681
CSW Industrials	0.90	0.81	2.8884	0.0721
Quest Diagnostics	0.85	0.75	2.7411	0.0684
Lauder (Estee)	0.95	0.85	2.8216	0.0704
Exponent, Inc.	0.90	0.79	2.9131	0.0727
Fastenal Co.	0.90	0.85	3.2203	0.0804
Gentex Corp.	0.95	0.91	2.7546	0.0687
Int'l Flavors & Frag	0.95	0.87	3.2238	0.0804
Ingredion Inc.	0.90	0.78	2.8793	0.0718
Iron Mountain	0.90	0.82	3.0897	0.0771
Hunt (J.B.)	0.95	0.86	2.8344	0.0707
J&J Snack Foods	0.90	0.84	2.9208	0.0729
Henry (Jack) & Assoc	0.85	0.71	2.7734	0.0692
ManTech Int'l 'A'	0.85	0.77	3.0653	0.0765
McCormick & Co.	0.80	0.66	2.7887	0.0696
Altria Group	0.90	0.83	2.9215	0.0729
MSA Safety	1.00	0.94	3.0076	0.0750
MSCI Inc.	0.95	0.87	2.9662	0.0740
Motorola Solutions	0.90	0.80	2.7926	0.0697
Vail Resorts	0.95	0.88	3.1939	0.0797
Maxim Integrated	0.95	0.87	2.9404	0.0734
Northrop Grumman	0.85	0.71	2.9032	0.0724
Old Dominion Freight	0.90	0.83	3.0708	0.0766
PerkinElmer Inc.	0.95	0.86	2.8896	0.0721
Philip Morris Int'l	0.95	0.88	3.2481	0.0811
Pool Corp.	0.85	0.75	3.2001	0.0799
Post Holdings	0.95	0.86	3.0105	0.0751
RLI Corp.	0.80	0.64	2.9883	0.0746
Rollins, Inc.	0.85	0.73	2.9697	0.0741
Selective Ins. Group	0.85	0.77	3.0004	0.0749
Sirius XM Holdings	0.95	0.91	2.7995	0.0699
Bio-Techne Corp.	0.80	0.67	3.2475	0.0810
Tetra Tech	0.90	0.84	3.0245	0.0755
Waters Corp.	0.95	0.86	2.7531	0.0687
West Pharmac. Svcs.	0.85	0.70	3.1887	0.0796
Western Union	0.80	0.67	2.7346	0.0682
Average	0.90	0.80	2.9609	0.0739
Proxy Group of Seven Natural Gas Distribution Companies	0.89	0.79	2.9927	0.0747

Source of Information:

Valueline Proprietary Database, March 2021

Atmos Energy Corporation
 Summary of Cost of Equity Models Applied to
 Proxy Group of Forty-Eight Non-Price Regulated Companies
 Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies

<u>Principal Methods</u>	<u>Proxy Group of Forty-Eight Non- Price Regulated Companies</u>
Discounted Cash Flow Model (DCF) (1)	12.83 %
Risk Premium Model (RPM) (2)	12.49
Capital Asset Pricing Model (CAPM) (3)	<u>11.69</u>
	<u>12.34 %</u>
	<u>12.49 %</u>
	<u>12.42 %</u>

Notes:

- (1) From page 2 of this Schedule.
- (2) From page 3 of this Schedule.
- (3) From page 6 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 Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Eight Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Bloomberg's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
Apple Inc.	0.69 %	14.50 %	12.50 %	12.10 %	17.93 %	14.26 %	0.74 %	15.00 %
Abbott Labs.	1.51	11.50	13.80	13.63	16.49	13.86	1.61	15.47
Assurant Inc.	1.76	11.50	17.50	17.50	17.50	16.00	1.90	17.90
ANSYS, Inc.	-	8.00	12.30	12.58	10.74	10.90	-	NA
Booz Allen Hamilton	1.80	10.50	10.60	13.00	9.67	10.94	1.90	12.84
Becton, Dickinson	1.35	7.50	8.90	8.30	11.85	9.14	1.41	10.55
Brown-Forman 'B'	0.97	11.00	NA	5.39	7.40	7.93	1.01	8.94
Broadridge Fin'l	1.48	8.50	NA	12.30	11.60	10.80	1.56	12.36
Brady Corp.	1.59	7.50	7.00	9.00	7.00	7.63	1.65	9.28
CACI Int'l	-	13.50	13.10	12.06	13.68	13.08	-	NA
Casey's Gen'l Stores	0.63	8.00	NA	15.81	7.85	10.55	0.66	11.21
Cadence Design Sys.	-	9.50	14.40	11.60	14.40	12.48	-	NA
Cerner Corp.	1.18	8.00	12.30	10.46	11.63	10.60	1.24	11.84
CSW Industrials	0.45	8.50	NA	12.00	12.00	10.83	0.47	11.30
Quest Diagnostics	1.91	10.00	26.50	(5.40)	3.26	13.25	2.04	15.29
Lauder (Estee)	0.71	11.00	10.70	18.20	27.18	16.77	0.77	17.54
Exponent, Inc.	0.83	12.50	NA	13.30	15.00	13.60	0.89	14.49
Fastenal Co.	2.21	8.00	9.00	8.70	7.95	8.41	2.30	10.71
Gentex Corp.	1.35	10.50	10.10	13.15	15.80	12.39	1.43	13.82
Int'l Flavors & Frag	2.20	7.50	9.80	21.48	7.72	11.63	2.33	13.96
Ingredion Inc.	2.76	7.50	NA	11.00	1.90	6.80	2.85	9.65
Iron Mountain	6.32	11.50	1.70	0.66	1.70	3.89	6.44	10.33
Hunt (J.B.)	0.71	8.00	15.00	15.00	21.53	14.88	0.76	15.64
J&J Snack Foods	1.55	10.00	NA	NA	6.00	8.00	1.61	9.61
Henry (Jack) & Assoc	1.18	9.00	10.90	12.47	10.64	10.75	1.24	11.99
ManTech Int'l 'A'	1.79	9.00	5.10	5.53	3.87	5.88	1.84	7.72
McCormick & Co.	1.53	5.50	6.70	5.87	6.00	6.02	1.58	7.60
Altria Group	6.94	6.00	4.00	4.35	4.35	4.68	7.10	11.78
MSA Safety	1.10	6.50	NA	9.00	18.00	11.17	1.16	12.33
MSCI Inc.	0.69	16.00	NA	15.00	15.31	15.44	0.74	16.18
Motorola Solutions	1.49	7.00	9.00	12.20	7.37	8.89	1.56	10.45
Vail Resorts	-	9.50	NA	87.08	72.95	56.51	-	NA
Maxim Integrated	-	8.00	10.00	11.95	21.91	12.97	-	NA
Northrop Grumman	1.84	7.00	NA	5.67	5.77	6.15	1.90	8.05
Old Dominion Freight	0.32	9.00	17.20	18.98	18.93	16.03	0.35	16.38
PerkinElmer Inc.	0.21	11.00	37.90	5.66	37.90	23.11	0.23	23.34
Philip Morris Int'l	5.19	6.50	8.70	10.75	12.75	9.67	5.44	15.11
Pool Corp.	0.83	15.00	NA	NA	17.00	16.00	0.90	16.90
Post Holdings	-	11.00	NA	20.30	31.20	20.83	-	NA
RLI Corp.	0.89	12.50	NA	NA	9.80	11.15	0.94	12.09
Rollins, Inc.	0.91	11.50	NA	NA	8.20	9.85	0.95	10.80
Selective Ins. Group	1.33	8.50	9.50	9.51	5.10	8.15	1.38	9.53
Sirius XM Holdings	0.96	35.50	12.70	40.32	10.10	24.66	1.08	25.74
Bio-Techne Corp.	0.32	12.50	14.00	19.03	15.00	15.13	0.34	15.47
Tetra Tech	0.62	13.50	15.00	13.85	15.00	14.34	0.66	15.00
Waters Corp.	-	6.00	7.10	8.19	7.77	7.26	-	NA
West Pharmac. Svcs.	0.22	17.00	25.80	18.55	25.80	21.79	0.24	22.03
Western Union	3.74	6.00	NA	4.57	9.19	6.59	3.86	10.45
Mean								13.33 %
Median								12.33 %
Average of Mean and Median								12.83 %

NA= Not Available

- (1) 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 May 28, 2021. 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, Bloomberg Professional Services, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Source of Information: Value Line Investment Survey
www.zacks.com Downloaded on 05/28/2021
www.yahoo.com Downloaded on 05/28/2021
Bloomberg Professional Services

Atmos Energy Corporation
 Indicated Common Equity Cost Rate
 Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

<u>Line No.</u>		<u>Proxy Group of Forty- Eight Non-Price Regulated Companies</u>
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	4.46 %
2.	Equity Risk Premium (2)	<u>8.03</u>
3.	Risk Premium Derived Common Equity Cost Rate	<u><u>12.49</u> %</u>

Notes: (1) Average forecast of Baa2 corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated June 1, 2021 (see pages 10 and 11 of Schedule DWD-3). The estimates are detailed below.

Second Quarter 2021	3.80 %
Third Quarter 2021	4.00
Fourth Quarter 2021	4.10
First Quarter 2022	4.20
Second Quarter 2022	4.20
Third Quarter 2022	4.30
2023-2027	5.30
2028-2032	<u>5.80</u>
Average	<u><u>4.46</u> %</u>

(2) From page 5 of this Schedule.

Atmos Energy Corporation
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Forty-Eight Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seven Natural Gas Distribution Companies

Proxy Group of Forty-Eight Non-Price Regulated Companies	Moody's Long-Term Issuer Rating May 2021		Standard & Poor's Long-Term Issuer Rating May 2021	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Apple Inc.	Aa1	2.0	AA+	2.0
Abbott Labs.	A2	6.0	A+	5.0
Assurant Inc.	Baa3	10.0	BBB	9.0
ANSYS, Inc.	NA	--	NA	--
Booz Allen Hamilton	NA	--	NA	--
Becton, Dickinson	Baa3	10.0	BBB	9.0
Brown-Forman 'B'	A1	5.0	A-	7.0
Broadridge Fin'l	Baa1	8.0	BBB+	8.0
Brady Corp.	NA	--	NA	--
CACI Int'l	NA	--	BB+	11.0
Casey's Gen'l Stores	NA	--	NA	--
Cadence Design Sys.	Baa2	9.0	BBB+	8.0
Cerner Corp.	NA	--	NA	--
CSW Industrials	NA	--	NA	--
Quest Diagnostics	Baa2	9.0	BBB+	8.0
Lauder (Estee)	A1	5.0	A+	5.0
Exponent, Inc.	NA	--	NA	--
Fastenal Co.	NA	--	NA	--
Gentex Corp.	NA	--	NA	--
Int'l Flavors & Frag	Baa3	10.0	BBB	9.0
Ingredion Inc.	Baa1	8.0	BBB	9.0
Iron Mountain	Ba3	13.0	BB-	13.0
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
J&J Snack Foods	NA	--	NA	--
Henry (Jack) & Assoc	NA	--	NA	--
ManTech Int'l 'A'	WR	--	BB+	11.0
McCormick & Co.	Baa2	9.0	BBB	9.0
Altria Group	A3	7.0	BBB	9.0
MSA Safety	NA	--	NA	--
MSCI Inc.	Ba1	11.0	BB+	11.0
Motorola Solutions	Baa3	10.0	BBB-	10.0
Vail Resorts	B2	15.0	BB	12.0
Maxim Integrated	Baa1	8.0	BBB+	8.0
Northrop Grumman	Baa2	9.0	BBB+	8.0
Old Dominion Freight	NA	--	NA	--
PerkinElmer Inc.	Baa3	10.0	BBB	9.0
Philip Morris Int'l	A2	6.0	A	6.0
Pool Corp.	NA	--	NA	--
Post Holdings	B2	15.0	B+	14.0
RLI Corp.	Baa2	9.0	BBB	9.0
Rollins, Inc.	NA	--	NA	--
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sirius XM Holdings	NA	--	BB	12.0
Bio-Techne Corp.	NA	--	NA	--
Tetra Tech	NA	--	NA	--
Waters Corp.	NA	--	NA	--
West Pharmac. Svcs.	NA	--	NA	--
Western Union	Baa2	9.0	BBB	9.0
Average	Baa2	8.8	BBB	8.9

Notes:

(1) From page 6 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 Forty-Eight Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seven Natural Gas Distribution Companies

<u>Line No.</u>	<u>Equity Risk Premium Measure</u>	<u>Proxy Group of Forty-Eight Non- Price Regulated Companies</u>
<u>Ibbotson-Based Equity Risk Premiums:</u>		
1.	Ibbotson Equity Risk Premium (1)	5.92 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.69
3.	Ibbotson Equity Risk Premium based on PRPM (3)	9.02
4.	Equity Risk Premium Based on <u>Value Line</u> Summary and Index (4)	4.60
5	Equity Risk Premium Based on <u>Value Line</u> S&P 500 Companies (5)	10.76
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	<u>12.78</u>
7.	Conclusion of Equity Risk Premium	8.63 %
8.	Adjusted Beta (7)	<u>0.93</u>
9.	Forecasted Equity Risk Premium	<u><u>8.03 %</u></u>

Notes:

- (1) From note 1 of page 9 of Schedule DWD-3.
- (2) From note 2 of page 9 of Schedule DWD-3.
- (3) From note 3 of page 9 of Schedule DWD-3.
- (4) From note 4 of page 9 of Schedule DWD-3.
- (5) From note 5 of page 9 of Schedule DWD-3.
- (6) From note 6 of page 9 of Schedule DWD-3.
- (7) Average of mean and median beta from page 6 of this Schedule.

Sources of Information:

Stocks, Bonds, Bills, and Inflation - 2021 SBBI Yearbook, John Wiley & Sons, Inc.
Value Line Summary and Index
Blue Chip Financial Forecasts, June 1, 2021
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 Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Eight 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)
Apple Inc.	0.90	1.01	0.96	9.46 %	2.88 %	11.96 %	12.06 %	12.01 %
Abbott Labs.	0.90	0.85	0.88	9.46	2.88	11.20	11.49	11.35
Assurant Inc.	0.90	1.00	0.95	9.46	2.88	11.87	11.99	11.93
ANSYS, Inc.	0.85	0.97	0.91	9.46	2.88	11.49	11.70	11.59
Booz Allen Hamilton	0.90	0.92	0.91	9.46	2.88	11.49	11.70	11.59
Becton, Dickinson	0.80	0.58	0.69	9.46	2.88	9.41	10.14	9.77
Brown-Forman 'B'	0.90	0.97	0.94	9.46	2.88	11.77	11.91	11.84
Broadridge Fin'l	0.80	0.84	0.82	9.46	2.88	10.64	11.06	10.85
Brady Corp.	1.00	1.05	1.02	9.46	2.88	12.53	12.48	12.51
CACI Int'l	0.95	1.01	0.98	9.46	2.88	12.15	12.20	12.17
Casey's Gen'l Stores	0.90	0.91	0.91	9.46	2.88	11.49	11.70	11.59
Cadence Design Sys.	0.90	0.98	0.94	9.46	2.88	11.77	11.91	11.84
Cerner Corp.	0.90	0.89	0.90	9.46	2.88	11.39	11.63	11.51
CSW Industrials	0.90	1.05	0.97	9.46	2.88	12.06	12.13	12.09
Quest Diagnostics	0.85	0.96	0.91	9.46	2.88	11.49	11.70	11.59
Lauder (Estee)	0.95	1.00	0.98	9.46	2.88	12.15	12.20	12.17
Exponent, Inc.	0.90	0.94	0.92	9.46	2.88	11.58	11.77	11.68
Fastenal Co.	0.90	0.95	0.92	9.46	2.88	11.58	11.77	11.68
Gentex Corp.	0.95	1.06	1.01	9.46	2.88	12.43	12.41	12.42
Int'l Flavors & Frag	0.95	1.08	1.02	9.46	2.88	12.53	12.48	12.51
Ingredion Inc.	0.90	0.92	0.91	9.46	2.88	11.49	11.70	11.59
Iron Mountain	0.90	1.02	0.96	9.46	2.88	11.96	12.06	12.01
Hunt (J.B.)	0.95	0.91	0.93	9.46	2.88	11.68	11.84	11.76
J&J Snack Foods	0.90	0.77	0.84	9.46	2.88	10.83	11.20	11.02
Henry (Jack) & Assoc	0.85	0.89	0.87	9.46	2.88	11.11	11.42	11.26
ManTech Int'l 'A'	0.85	1.11	0.98	9.46	2.88	12.15	12.20	12.17
McCormick & Co.	0.80	0.70	0.75	9.46	2.88	9.97	10.57	10.27
Altria Group	0.90	0.88	0.89	9.46	2.88	11.30	11.56	11.43
MSA Safety	1.00	0.99	1.00	9.46	2.88	12.34	12.34	12.34
MSCI Inc.	0.95	0.94	0.94	9.46	2.88	11.77	11.91	11.84
Motorola Solutions	0.90	0.96	0.93	9.46	2.88	11.68	11.84	11.76
Vail Resorts	0.95	1.14	1.05	9.46	2.88	12.81	12.69	12.75
Maxim Integrated	0.95	0.99	0.97	9.46	2.88	12.06	12.13	12.09
Northrop Grumman	0.85	0.80	0.83	9.46	2.88	10.73	11.13	10.93
Old Dominion Freight	0.95	0.97	0.96	9.46	2.88	11.96	12.06	12.01
PerkinElmer Inc.	0.90	0.84	0.87	9.46	2.88	11.11	11.42	11.26
Philip Morris Int'l	0.95	0.91	0.93	9.46	2.88	11.68	11.84	11.76
Pool Corp.	0.85	0.95	0.90	9.46	2.88	11.39	11.63	11.51
Post Holdings	0.95	0.90	0.93	9.46	2.88	11.68	11.84	11.76
RLI Corp.	0.80	0.90	0.85	9.46	2.88	10.92	11.28	11.10
Rollins, Inc.	0.85	0.69	0.77	9.46	2.88	10.16	10.71	10.44
Selective Ins. Group	0.85	0.97	0.91	9.46	2.88	11.49	11.70	11.59
Sirius XM Holdings	0.95	1.10	1.02	9.46	2.88	12.53	12.48	12.51
Bio-Techne Corp.	0.80	0.93	0.86	9.46	2.88	11.02	11.35	11.18
Tetra Tech	0.95	1.06	1.00	9.46	2.88	12.34	12.34	12.34
Waters Corp.	0.95	0.86	0.91	9.46	2.88	11.49	11.70	11.59
West Pharmac. Svcs.	0.80	0.75	0.78	9.46	2.88	10.26	10.78	10.52
Western Union	0.80	1.05	0.93	9.46	2.88	11.68	11.84	11.76
		Mean	0.92			11.55 %	11.75 %	11.65 %
		Median	0.93			11.63 %	11.81 %	11.72 %
		Average of Mean and Median	0.93			11.59 %	11.78 %	11.69 %

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.

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]		[2]	[3]	[4]
		Market Capitalization on May 28, 2021		Applicable Decile of the NYSE/AMEX/NASDAQ (2)	Applicable Size Premium (3)	Spread from Applicable Size Premium (4)
		(millions)	(times larger)			
1.	<u>Atmos Energy Corporation</u>	\$ 597.101		8	1.46%	
2.	<u>Proxy Group of Seven Natural Gas Distribution Companies</u>	\$ 4,615.314	7.7 x	4	0.75%	0.71%
			[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	\$ 29,025.803	\$ 1,966,078.882	-0.22%
			2	13,178.743	28,808.073	0.49%
			3	6,743.361	13,177.828	0.71%
			4	3,861.858	6,710.676	0.75%
			5	2,445.693	3,836.536	1.09%
			6	1,591.865	2,444.745	1.37%
			7	911.586	1,591.765	1.54%
			8	451.955	911.103	1.46%
			9	190.019	451.800	2.29%
		Smallest	10	2.194	189.831	5.01%

*From 2021 Duff & Phelps 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 0.71% in Column [4], Line No. 2 is derived as follows 0.71% = 1.46% - 0.75%.

Atmos Energy Corporation
Market Capitalization of Atmos Energy Corporation and the
Proxy Group of Seven Natural Gas Distribution Companies

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Exchange	Common Stock Shares Outstanding at Fiscal Year End 2020 (millions)	Book Value per Share at Fiscal Year End 2020 (1)	Total Common Equity at Fiscal Year End 2020 (millions)	Closing Stock Market Price on May 28, 2021	Market-to- Book Ratio on May 28, 2021 (2)	Market Capitalization on May 28, 2021 (3) (millions)
Atmos Energy Corporation		NA	NA	340.035 (4)	NA		
Based upon Proxy Group of Seven Natural Gas Distribution Companies						175.6 (5)	\$ 597.101 (6)
Proxy Group of Seven Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	\$ 125.882	\$ 53.949	\$ 6,791.203	\$ 99.170	183.8 %	\$ 12,483.765
New Jersey Resources Corporation	NYSE	95.949	19.226	1,844.692	42.720	222.2	4,098.949
Northwest Natural Holding Company	NYSE	30.589	29.054	888.733	52.880	182.0	1,617.546
ONE Gas, Inc.	NYSE	53.167	42.006	2,233.311	74.320	176.9	3,951.352
South Jersey Industries, Inc.	NYSE	100.592	16.571	1,666.876	26.660	160.9	2,681.781
Southwest Gas Holdings, Inc.	NYSE	57.193	46.771	2,674.953	66.010	141.1	3,775.305
Spire Inc.	NYSE	51.612	44.182	2,280.300	71.660	162.2	3,698.501
Average		\$ 73.569	\$ 35.966	\$ 2,625.724	\$ 61.917	175.6 %	\$ 4,615.314

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 initial requested common equity ratio.

(5) The market-to-book ratio of Atmos Energy Corporation on May 28, 2021 is assumed to be equal to the market-to-book ratio of Proxy Group of Seven Natural Gas Distribution Companies on May 28, 2021 as appropriate.

(6) Column [3] multiplied by Column [5].

Source of Information: 2020 Annual Forms 10K
yahoo.finance.com
Bloomberg Professional

Atmos Energy Corporation
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances and Flotation Costs for FY 2019, 2018, 2017, and 2016

		[Column 1]	[Column 2]	[Column 3]	[Column 4]	[Column 5]	[Column 6]	[Column 7]
Fiscal Year	Transaction (1)	Shares Issued	Average Offering Price per Share (2)	Net Proceeds per Share (3)	Gross Equity Issue before Costs	Total Net Proceeds	Total Flotation Costs (4)	Flotation Cost Percentage (5)
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%
					<u>\$ 1,100,000,000</u>	<u>\$ 1,086,600,000</u>	<u>\$ 13,400,000</u>	<u>1.22%</u>

Flotation Cost Adjustment

	Average Dividend Yield	Average Projected EPS Growth Rate	Adjusted Dividend Yield	Average DCF Cost Rate Unadjusted for Flotation (6)	DCF Cost Rate Adjusted for Flotation (7)	Flotation Cost Adjustment (8)
Proxy Group of Seven Natural Gas Distribution Companies	<u>3.44 %</u>	<u>6.02 %</u>	<u>3.54 %</u>	<u>9.56 %</u>	<u>9.60 %</u>	<u>0.04 %</u>

See page 2 of this Schedule for notes.

Source of Information: Company SEC filings

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-03
Page 1 of 1

REQUEST:

Refer to the Direct Testimony of William D. Matthews, 14:4-8. Further describe the adjustment required in next year's filing.

RESPONSE:

The adjustment described to remove the impact of Winter Storm Uri from the fiscal year 2021 ARM filing will also be made in the fiscal year 2022 ARM filing. The Company will include an adjustment to remove the \$2.2 billion of debt as well as the impact on the Company's deferred income taxes associated with Winter Storm Uri for each of the periods that they remain on the Company's financial statements.

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-04
Page 1 of 2

REQUEST:

Refer to the Petition's Relied Upons, File <p. ADIT 1N ARM Fiscal 2021.xlsx>, Tab "Div 093" and respond to the following:

- a. Define the transactions within the category Fixed Asset Cost Adjustment.
- b. Define the transactions within the category Depreciation Adjustment.
- c. Provide a comprehensive discussion why there has only been minimal change in the balances of the (i) Fixed Cost Adjustment and (ii) Depreciation Adjustment throughout the test period.
- d. Provide the supporting documentation and calculations for the journal entry(ies) made in March 2021 affecting the Fixed Asset timing difference.
- e. Provide the supporting documentation and calculations for the journal entry(ies) made in September 2021 affecting the Depreciation Adjustment timing difference.

RESPONSE:

- a. The capitalization of costs for assets is treated differently for book and tax purposes. Differences may arise from the acquisition of assets either through a stock or asset purchase and reflect the difference in treatment, cost allocation, or basis presentation of the acquired assets. Other cost basis differences are the result of differences in methods between book accounting and tax accounting for items such as capitalized interest, contributions in aid of construction, capitalization of overhead and capitalization of repair and maintenance expenses. In addition, tax legislation such as the enactment or extension of bonus depreciation results in cost basis differences. Cost basis differences are initially reflected within CWIP (Construction Work in Process). As projects within CWIP are completed and assets are placed in service, the basis difference moves to Fixed Asset – Cost Adjustment.
- b. For federal income tax purposes, the Company depreciates assets using the modified accelerated cost recovery method promulgated by §168 of the Internal Revenue Code ("IRC"). For financial statement purposes, Atmos follows a method of depreciation that is acceptable under generally accepted accounting principles ("GAAP"). Use of the modified accelerated cost recovery method for tax purposes results in assets being depreciated faster for income tax accounting than for financial accounting. This difference results in a deferred tax liability early in the life of the assets. This deferred liability reverses as the assets are depreciated.
- c. The minimal change in fixed asset cost adjustment is due to the insignificant change in plant additions and depreciation adjustments in FY21.

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-04
Page 1 of 2

- d. The movement in the fixed asset cost adjustment for FY21 Q1 totaled (\$1,675,245). This movement includes adjustments that create book to tax basis differences such as aid in construction, capitalized interest, capitalized overhead and repairs. The movement of (\$1,675,245) is recorded to the Company's ledger as part of the overall ADIT journal entry process that includes the total Tennessee ADIT movement and other related tax entries.

Please see Attachment 1 for support of March 2021 movement.

- e. The Depreciation Adjustment is recorded to the Company's ledger as part of the overall ADIT journal entry process that includes the total Tennessee ADIT movement and other related tax entries.

Please see Attachment 2 for the September 2021 movement

ATTACHMENTS:

CPAD_1-04_Att1 - Fixed Asset Timing Differences.xlsx
CPAD_1-04_Att2 - Depreciation Adjustment.xlsx

Atmos Energy Corporation
 TN Docket No. 22-00010
 Staff Data Request 1-4 (d)
 Fixed Asset timing Difference Summary

Rate Division:
 S093000

Adjustment Description	Category	Adj Code	Fiscal 2021	Fiscal 2021	Fiscal 2021	
			12/31/2020	3/31/2021	Entries reflected in March Ledgers	
Fixed Asset Cost Adjustment	FXA	FXA01	(61,461,314)	(63,136,559)	(1,675,245)	<i>refer to Note 1</i>

Note 1: Fixed asset cost adjustment includes the following componets comprising of FY21 Q2 March Entry

Aid in Construction Adjustment	526,294
Capitalized Interest Adjustment	(6,461)
Capitalized Overhead Adjustment	(147,965)
Repairs Deduction	(2,047,113)
	<u>(1,675,245)</u>

Atmos Energy Corporation
TN Docket No. 22-00010
Staff Data Request 1-4 (e)
Fixed Asset depreciation Summary

Rate Division:

S093000

Adjustment Description	Category	Adj Code	Fiscal 2021	Fiscal 2021	Fiscal 2021
			6/30/2021	9/30/2021	Entries reflected in September Ledgers
Depreciation Adjustment	FXA	FXA02	(25,471,821)	(26,716,728)	(1,244,907)

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-05
Page 1 of 1

REQUEST:

Refer to the Petition's Relied Upons, File <p. ADIT TN ARM Fiscal 2021.xlsx>, Tab "Div 093" and respond to the following:

- a. Provide all supporting documentation and calculations supporting the \$11,452,512 balance of ADIT associated with the State-Net Operating Loss category for September 2021.
- b. Provide a comprehensive discussion of the nature of the timing difference "State Bonus Depreciation".
- c. Provide the documentation and supporting calculations for the September 2021 balance of "State Bonus Depreciation".

RESPONSE:

- a. Please see Attachment 1. Please see the updated amount included in the Company's response to CPAD 1-09.
- b. Tennessee has fully decoupled from the federal accelerated depreciation provisions under IRC 168(k) such as bonus depreciation. This results in the federal and state depreciation calculations adjustments to differ in current periods. The deferred tax asset for state bonus depreciation represents state depreciation deductions that were decoupled from federal bonus depreciation but will be able to deduct in future periods throughout the asset life.
- c. Please see Attachment 2.

ATTACHMENTS:

CPAD_1-05_Att1 - State NOL.xlsx
CPAD_1-05_Att2 - State Bonus Depreciation.xlsx

Atmos Energy Corporation
TN Docket No. 22-00010
Staff Data Request 1-5(a)
State Net Operating Loss Deferred Reconciliation

	Deferred Balance	
State Net Operating Loss Deferred as of 9-30-2020	4,832,811	<i>Note 1</i>
FY20 Return to Provision Adjustment	(7,716)	<i>Note 2</i>
FY20 Return	4,825,095	<i>Note 3</i>
FY21 Activity	57,990	
StateNet Operating Loss Deferred as of 9-30-2021	4,883,085	
Balance as provided in file ADIT to Rates Sep 2021 - REVISED	4,883,084	
Difference	1	

Note 1

FY20 State Net Operating Loss deferred as of 9-30-2020 Provision

Note 2

FY20 Return to provision adjustment reflects the difference between the State Net Operating Loss deferred recorded as of 9-30-2020 provision versus the State Net Operating loss deferred as filed on the FY20 Return.

Note 3

FY20 State Net Operating Loss per state income tax return filed with TN

Atmos Energy Corporation
TN Docket No. 22-00010
Staff Data Request 1-5(c)
State Bonus Depreciation Deferred Reconciliation

	Deferred Balance	
State Bonus Depreciation Deferred as of 9-30-2020	4,906,257	<i>Note 1</i>
FY20 Return to Provision Adjustment	163,216	<i>Note 2</i>
FY20 Return	5,069,473	<i>Note 3</i>
FY21 Activity	(529,304)	
State Bonus Depreciation Deferred as of 9-30-2021	4,540,169	
Balance as provided in file "ADIT to Rates Sep 2020"	4,540,167	
Difference	2	

Note 1

FY20 Bonus Depreciation Deferred as of 9-30-2020 Provision

Note 2

FY20 Return to provision adjustment reflects the difference between the bonus depreciation deferred recorded as of 9-30-2020 versus the bonus depreciation as filed on the TN return

Note 3

FY20 State Bonus Depreciation per state income tax return filed with TN

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-06
Page 1 of 1

REQUEST:

Refer to the Petition's Relied Upens, File <p. ADIT TN ARM Fiscal 2021.xlsx>, Tab "Div 093". Provide the justification for inclusion of the balance of "Charitable Contribution Carryover" within the ADIT account for Division 093.

RESPONSE:

The inclusion of the Charitable Contributions Carryover is has been consistent based on the ARM model as per the Stipulation and Settlement Agreement under Docket Nos. 14-00146 and 18-00112.

For financial statement purposes, charitable contributions are deducted when paid. For tax purposes, pursuant to Internal Revenue Code §170(b)(2) the total deductions for any taxable year shall not exceed 10 percent of the taxpayer's taxable income. Per §170(d)(2), any contribution made by a corporation in a taxable year in excess of the amount deductible for such year under subsection (b)(2)(A) shall be deductible for each of the 5 succeeding taxable years in order of time. The ADIT item represents the contributions deducted for book purposes and not yet deductible for tax.

Deferred tax items is created as a result of the timing difference between book and tax within the ADIT account. It is included in the ADIT component of rate base as filed in the docket pursuant to the ARM tariff.

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-07
Page 1 of 1

REQUEST:

Refer to the Petition's Relied Upons, File <p. ADIT TN ARM Fiscal 2021.xlsx>, Tab "Div 093". Provide a description of the line item "Regulatory Liability - 2017 Gross Up", providing the rationale for inclusion in the balance of ADIT. Further, provide the support for the September 2021 balance.

RESPONSE:

This ADIT item represents the gross up of the regulatory liability for excess deferred income taxes ("EDIT") resulting from the federal income tax rate reduction enacted by the Tax Cuts and Jobs Act (TCJA). This gross up is necessary to be included in the ADIT because it represents the tax benefit that the customers should receive due to the fact that the Company has less tax liability as a result of the EDIT refund to its customers. Please see Attachment 1 for the September 2021 balance.

ATTACHMENT

CPAD_1-07_Att1 - Regulatory Liability Gross Up Support.xlsx

Atmos Energy Corporation
TN Docket No. 22-00010
Staff Data Request 1-7
Regulatory Liability - 2017 Gross Up Reconciliation

	TN Direct Division		
	Total Regulatory	ExcessDeferred	
	Liability	Income Tax	Gross Up
Orig. Regulatory Liability	(27,673,070)	(19,575,930)	(8,097,140)
Regulatory Liability Adj. with 6/1/2019 Implementation	(1,351,460)	(956,023)	(395,437)
Regulatory liability Adj. with 3/1/2021 Implementation	(312,735)	(221,229)	(91,506)
Reg Liab in 2022 TN ARM 22-0010 Filing	(29,337,265)	(20,753,181)	(8,584,084)
YTD Amortization as of 9/30/2021	6,038,714	4,718,025	1,320,690
Balance recorded 9/30/21	(23,298,551)	(16,035,157)	(7,263,394)
Balance as provided in file ADIT to Rates Sep 2021			(7,263,394)

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-08
Page 1 of 1

REQUEST:

Refer to the Petition's Relied Upens, File <p. ADIT TN ARM Fiscal 2021.xlsx >. Provide the rationale for inclusion of the book/tax timing difference identified as "Regulatory Liability" - NSC for (i) Division 091, and (ii) Division 093 within the balance of ADIT.

RESPONSE:

In 2017, the FASB issued ASU 2017-07, which disallowed non service costs (NSC) relating to OPEB to be capitalized into Plant, Property, and Equipment. As these costs are no longer eligible for capitalization under GAAP but continue to be capitalizable for ratemaking the costs are shown as a regulatory asset.

As a result of the NSC costs relating to pension obligations, book/tax timing differences arises due to the difference treatments for book and tax. For book purposes, Pension asset or liability is accrued throughout the year for the respective divisions. For tax, pension benefits are only deductible when paid pursuant to IRC §404. A deduction is afforded under IRC §404 only as the plan is funded during or within 8 ½ months of year end. A deferred tax asset or liability is booked for the difference between the expenses recognized on the books and those currently deductible for tax.

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-09
Page 1 of 1

REQUEST:

Refer to the Petition's Relied Upons, File <p. ADIT TN ARM Fiscal.xlsx >, Tab "Div 002". Provide the rationale for inclusion of the following book/tax timing differences within the ADIT balance in Division 002:

- a. SEBP Adjustment (Please define the nature of these transactions);
- b. SERP DTL Offset;
- c. Rabbi Trust;
- d. VEBA Contribution Adjustment;
- e. Directors' Stock Award; and
- f. FAS 106 Adjustment.

For each book/tax timing difference identified above, provide the Tennessee jurisdiction expense included in test year results.

RESPONSE:

The inclusion of these listed accounts in the 002 ADIT balances are part of the methodologies for ADIT since Docket No. 14-00146.

However, In the settlement of Docket No. 21-00019, the Company removed items related to SEBP and therefore agrees that the related items above a. SEBP Adjustment and b. SERP DTL Offset from ADIT should be removed and have been in Attachment 1.

The model in attachment 1 has a revised deficiency of \$2,269,523 or a \$1,392,637 reduction from the original filed model with a deficiency of \$3,662,160.

The six adjustments made are described briefly below and in more detail on the DR's referenced with each. The model location of the changes are also noted.

- DR 1-05, WP 7-2, 7-4 Adjust State-Net Operating Loss to remove Uri Impact
- DR 1-09, WP 7-2, 7-4 Remove SEBP/SERP items from ADIT
- DR 1-13, WP 7-10 Exclude interest and RWIP interest from avg Reg Asset
- DR 1-18, WP 9-2 Short-Term Debt Rate Adjusted
- DR 1-28, Sch 4 Remove legal fees not related to Tennessee
- DR 1-29, WP 7-8 Remove capitalized SERP costs

ATTACHMENT:

CPAD_1-09_Att1 - 2022 ARM - Updated.xlsx

Tennessee Distribution System
Cost of Service
Twelve Months Ended September 30, 2021

Line No.	Description	Reference	Amount
	(a)	(b)	(c)
1	Cost of Gas	Schedule 3	\$55,628,730
2			
3	Operation & Maintenance Expense	Schedule 4	22,347,772
4			
5	Taxes Other Than Income Taxes	Schedule 5	8,295,367
6			
7	Depreciation & Amortization Expense	Schedule 6	17,174,980
8			
9	Return	Schedule 7	33,588,589
10			
11	Federal Income and State Excise Tax	Schedule 8	9,176,704
12			
13	AFUDC	Wp 1-2	(659,575)
14			
15	Interest on Customer Deposits	Wp 1-1	34,768
16			
17	Total Cost of Service		<u>\$ 145,587,335</u>
18			
19			
20	Revenue at Present Rates	Sch 11-2	<u>\$ 141,610,603</u>
21			
22	Net Revenue Deficiency (Sufficiency)		\$ 3,976,732
23	Amortization of EDITL	WP 7-9	\$ (6,112,798)
24	Annual Reconciliation Revenue Requirement	Schedule 1R	\$ 4,405,588
25			
26	Total Revenue Deficiency (Sufficiency)		<u><u>\$ 2,269,523</u></u>
27			

Tennessee Distribution System
Cost of Service
Twelve Months Ended September 30, 2021

Line No.	Description (a)	Reference (b)	Amount (c)
1	Cost of Gas	Schedule 3	\$55,628,730
2			
3	Operation & Maintenance Expense	Schedule 4	22,347,772
4			
5	Taxes Other Than Income Taxes	Schedule 5	8,295,367
6			
7	Depreciation & Amortization Expense	Schedule 6	15,745,319
8			
9	Return	Schedule 7R	32,058,035
10			
11	Federal Income and State Excise Tax	Schedule 8R	8,665,989
12			
13	AFUDC	Wp 1-2	(659,575)
14			
15	Interest on Customer Deposits	Wp 1-1	34,768
16			
17	Total Cost of Service		<u>\$ 142,116,406</u>
18			
19			
20	Actual Adjusted Revenue	Schedule 2	<u>\$ 138,165,384</u>
21			
22	Net Revenue Deficiency (Sufficiency)		\$ 3,951,022
23	Carrying Costs	Schedule 9	<u>\$ 454,566</u>
24	Annual Reconciliation Revenue Requirement		<u>\$ 4,405,588</u>

**Tennessee Distribution System
Interest on Customer Deposits
Twelve Months Ended September 30, 2021**

Line No.	Description	Amount
	(a)	(b)
1	Average Customer Deposit Balance	\$ 1,069,783
2		
3	Interest Rate on Customer Deposits	<u>3.25%</u>
4		
5	Adjusted Customer Deposit Interest	<u><u>\$ 34,768</u></u>

Tennessee Distribution System
Allowance for Funds Used During Construction
Twelve Months Ended September 30, 2021

Line No.	Description (a)	Amount (b)
1	Base Period AFUDC per books - Div 093 (1)	\$ (892,947)
2		
3	Less State Excise Tax Effect	<u>(58,042)</u>
4		
5		\$ (834,905)
6		
7	Less Federal Tax Effect	<u>(175,330)</u>
8		
9	Net AFUDC - Base Period	\$ (659,575)
10		
11	Change from Base Period to Attrition Year	<u>-</u>
12		
13	Projected Attrition Year Net AFUDC	<u><u>\$ (659,575)</u></u>
14		
15	Note:	
16	1. Twelve months ended September 30, 2021 - Accounts 4320 and 4191	

Tennessee Distribution System
Summary of Actual Revenues for the Historic Test Period
Twelve Months Ended September 30, 2021

Line	Description		Amount
	(a)	(b)	(c)
1	Base period per books revenue (1)		\$ 137,262,701
2	Adjustments:		
3	Cost of Service Reserve		(1,043,815)
4	Reconciliation Revenue (Oct-May)		(537,823)
5	Reconciliation Revenue (Jun-Sep)		(1,050,601)
6	EDITL (Oct-Feb)		580,157
7	EDITL (Mar-Sep)		2,954,766
8	Test Year Revenue:		
9	Ongoing Gross Margin	\$ 82,536,654	
10	Gas cost	55,628,730	
11	Total		\$ 138,165,384
12			
13			
14	Total Revenue		\$ 138,165,384
15			
16	Note:		
17	1. Twelve months ended September 30, 2021		

Tennessee Distribution System
Cost of Gas
Twelve Months Ended September 30, 2021

Line No.	Description (a)	Amount (b)
1	Base period per books cost of gas (1)	\$ 56,805,646
2		
3	Adjustments	
4	Net Elimination of Intercompany Leased Storage Property	<u>(1,176,917)</u>
5		
6	Total Adjusted Gas Cost	<u><u>\$ 55,628,730</u></u>
7		
8		
9		
10		
11		
12	Note:	
13	1. Twelve months ended September 30, 2021	

Tennessee Distribution System
ELIMINATION OF LEASED PROPERTY-RENT
Twelve Months Ended September 30, 2021

Line No.	Description	Building Rent O&M	Storage Expense O&M	Leased Property Depreciation	Storage Expense Other Taxes	Storage Rent Gas Cost
	(a)	(b)	(c)	(d)	(e)	(f)
1	Oct-20	\$ -	\$ 25,141	\$ 21,503	\$ -	\$ (95,918)
2	Nov-20	-	28,713	21,503	16	(95,918)
3	Dec-20	-	41,069	21,503	8	(98,508)
4	Jan-21	-	34,789	21,503	2,108	(98,508)
5	Feb-21	-	35,384	21,503	2,108	(98,508)
6	Mar-21	-	39,922	21,503	6,166	(98,508)
7	Apr-21	-	30,367	21,503	2,108	(98,508)
8	May-21	-	43,921	21,503	2,108	(98,508)
9	Jun-21	-	52,077	21,503	2,108	(98,508)
10	Jul-21	-	34,813	21,503	14,442	(98,508)
11	Aug-21	-	42,205	21,503	2,108	(98,508)
12	Sep-21	-	28,770	21,503	2,108	(98,508)
13						
14	Total Per Books	\$ -	\$ 437,170	\$ 258,038	\$ 35,388	\$ (1,176,917)

**Tennessee Distribution System
Operation and Maintenance Expenses
Twelve Months Ended September 30, 2021**

Line No.	Description (a)	Amount (b)
1	Base period per books O&M Expense (1)	\$ 21,911,388
2	(with ratemaking adjustments)	
3		
4		
5		
6		
7	<u>Adjustments to O&M</u>	
8		
9	Inclusion of Barnsley Storage Operating Expense	\$ 437,170
10	<u>Less Consumer Advocate Adjustments:</u>	
11	CPAD Adjustment #1-28 Certain Legal Costs	786
12		
13		
14		
15	Total Adjusted O&M TYE 9.30.21	<u>\$ 22,347,772</u>
16	Note:	
17	1. Twelve months ended September 30, 2021	

**Tennessee Distribution System
Operation and Maintenance Expenses
Twelve Months Ended September 30, 2021**

Line No.	Tennessee		SSU		General Office		Total		
	Historic Base		Historic Base		Historic Base		Historic Base	Attrition	Difference
1 Labor	\$	3,236,600	\$	3,458,858	\$	1,377,589	\$	8,073,046	
2 Benefits		987,407		1,410,233		360,086		2,757,726	
3 Employee Welfare		43,254		1,813,407		650,225		2,506,886	
4 Insurance		173,926		1,285,394		12,720		1,472,039	
5 Rent, Maint., & Utilities		741,634		326,336		193,732		1,261,701	
6 Vehicles & Equip		375,327		2,018		36,351		413,696	
7 Materials & Supplies		420,156		46,033		40,314		506,504	
8 Information Technologies		49,936		1,327,400		80,184		1,457,520	
9 Telecom		132,378		131,025		101,182		364,585	
10 Marketing		123,615		10,901		149,065		283,581	
11 Directors & Shareholders & PR		163		268,925		-		269,088	
12 Dues & Donations		122,356		31,020		4,439		157,815	
13 Print & Postages		32,513		21,863		6,331		60,707	
14 Travel & Entertainment		63,088		12,358		66,288		141,734	
15 Training		27,975		28,103		11,549		67,627	
16 Outside Services		5,160,976		810,915		915,417		6,887,307	
17 Provision for Bad Debt		728,391		-		-		728,391	
18 Miscellaneous		4,410		(4,139,784)		(90,520)		(4,225,894)	
19 Total O&M Expenses	\$	12,424,104	\$	6,845,006	\$	3,914,952	\$	23,184,062	
20									
21 Disallowed Items									
22 Other (Sub 05416 and 05412)	\$	(1,636)	\$	(135)	\$	(195)	\$	(1,966)	
23 Incentive Comp (MFR 38)		-		(688,190)		(591,134)		(1,279,325)	
24 FAS 87 Accrual (Sub Account 01202)		(170,007)		(135,594)		(66,891)		(372,492)	
25 SERP (Sub 07489,07490,07492,07493)	\$	-	\$	(111,207)	\$	(17,266)	\$	(128,473)	
26									
27 Rate Case Expense							\$	-	
28									
29 Actual Allocable Pension Contribution	\$	509,581					\$	509,581	
30									
31 Total O&M	\$	12,762,042	\$	5,909,880	\$	3,239,465	\$	21,911,388	

**Tennessee Distribution System
Operation and Maintenance Expenses by FERC
Twelve Months Ended September 30, 2021**

Division 093		
Line No.	FERC Account	Historic Base Period
1	7350	765
2	8500	4,886
3	8560	8,810
4	8570	101
5	8700	1,441,042
6	8711	33,637
7	8740	5,639,286
8	8750	562,863
9	8760	236
10	8770	66
11	8780	432,776
12	8800	6,679
13	8810	314,179
14	8870	18,765
15	8890	191,208
16	8920	7,174
17	8930	3,424
18	8940	1,035
19	9020	351,996
20	9030	744,282
21	9040	728,391
22	9090	11,476
23	9110	223,904
24	9120	102,282
25	9130	2,525
26	9200	137,920
27	9210	2,972
28	9220	10,759,958
29	9230	111,533
30	9240	134,448
31	9250	100,284
32	9260	1,000,795
33	9280	745
34	9302	103,617
35	Total	23,184,062

**Tennessee Distribution System
Operation and Maintenance Expenses by FERC
Twelve Months Ended September 30, 2021**

Division 091		
Line No.	FERC Account	Historic Base Period
36	8170	519
37	8180	363
38	8190	10,059
39	8210	1,992
40	8240	-
41	8250	14,202
42	8500	29,477
43	8560	467
44	8570	1,072
45	8600	165
46	8700	2,472,527
47	8710	90
48	8740	106,728
49	8750	424,669
50	8760	114,927
51	8770	(594)
52	8780	2,152
53	8800	774,628
54	8810	326,163
55	8870	(73)
56	8890	75,568
57	8900	1,549
58	8910	8,219
59	9010	116,249
60	9020	383
61	9030	2,099,956
62	9090	175,229
63	9100	356
64	9110	147,232
65	9120	2,363
66	9130	9,418
67	9200	(191,538)
68	9210	50,879
69	9220	(9,341,331)
70	9230	149,597
71	9240	(330)
72	9250	51,472
73	9260	2,357,217
74	9302	7,980
75	Total	(0)

**Tennessee Distribution System
Operation and Maintenance Expenses by FERC
Twelve Months Ended September 30, 2021**

Division 002		
Line No.	FERC Account	Historic Base Period
76	8510	63
77	8520	72,597
78	8560	20,481
79	8660	34
80	8670	30,773
81	8700	150,440
82	8740	28,551
83	8800	17,909
84	8810	(8,188)
85	8850	-
86	9010	3,748
87	9020	24,023
88	9030	95,848
89	9100	-
90	9110	-
91	9120	147,201
92	9160	-
93	9200	(42,148,810)
94	9210	32,459,021
95	9220	(111,140,871)
96	9230	15,747,764
97	9240	113,148
98	9250	31,038,455
99	9260	66,209,354
100	9302	6,939,123
101	9310	4,951,847
102	9320	318,614
103	Total	5,071,126

**Tennessee Distribution System
Operation and Maintenance Expenses by FERC
Twelve Months Ended September 30, 2021**

Division 012		
Line No.	FERC Account	Historic Base Period
104	8700	3,948
105	8740	67,351
106	9010	4,431,514
107	9030	21,217,974
108	9200	3,245,026
109	9210	8,472,083
110	9220	(50,150,332)
111	9230	1,204,475
112	9240	79,543
113	9250	870
114	9260	10,245,449
115	9302	-
116	9310	1,176,446
117	9320	5,651
118	Total	(0)

[illegible]

Atmos Energy Corp - Tennessee Distribution System
Pension Benchmark Calculation
Twelve Months Ended September 30, 2021

Line No.	Description	Number of Participants	Estimated Liability	Percent of Contribution Applicable to Group	Actual Year Contribution	Allocation Factor to Tennessee	Amount Allocable to Tennessee	Composite Labor Capitalization Rate	Pension Contribution Assigned to Capital/Reduction to O&M Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	All Other (not allocable to Tennessee)	3,956	\$ 471,703,000	78.1%	\$ 7,806,795.86	0.00%	\$ -		-
2	Co 010 - Shared Services	473	66,432,000	11.0%	1,099,465	4.13%	45,424		-
3	Co 010 - CSO	283	22,700,000	3.8%	375,690	4.73%	17,762		-
4	Active Tennessee Jurisdiction Employees	72	12,057,000	2.0%	199,546	100.00%	199,546	60.78%	(121,289)
5	Inactive Tennessee Jurisdiction Employees	188	18,631,000	3.1%	308,347	100.00%	308,347		-
6	Active Division General Office Employees	18	4,422,000	0.7%	73,185	41.91%	30,672	46.12%	(14,147)
7	Inactive Division General Office Employees (pre-merger)	47	5,562,000	0.9%	92,052	26.55%	24,440		-
8	Inactive Division General Office Employees (post-merger)	7	2,714,000	0.4%	44,917	41.91%	18,825		-
9									
10	Total Amount of Contribution Allocable to Tennessee	5,044	\$ 604,221,000	100.00%	\$ 10,000,000		\$ 645,017		\$ (135,436)

1 For General Office employees who worked at United Cities Gas Company prior to the merger with Atmos Energy, the Company has applied the allocation factor used to allocate labor expense in Docket No. 95-02258.

Source:

**Tennessee Distribution System
Taxes Other Than Income Taxes
Twelve Months Ended September 30, 2021**

Line No.	Description (a)	Total (b)
1	Base period per books Other Taxes Expense (1)	\$ 8,259,980
2		
3		
4		
5		
6		
7	Inclusion of Barnsley Storage Other taxes	<u>35,388</u>
8		
9	Adjusted Taxes Other Than Income Taxes	<u><u>\$ 8,295,367</u></u>
10		
11	Note:	
12	1. Twelve months ended September 30, 2021 - Account 408	

Tennessee Distribution System
Taxes Other Than Income Taxes
Twelve Months Ended September 30, 2021

Line No.	Descripton	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Base Period
1	<u>Division 093</u>													
2	FICA	12,942	37,713	17,283	17,285	17,388	10,159	13,617	12,935	11,993	29,303	9,549	12,553	202,721
3	FUTA	-	9	(3)	1,544	180	(83)	14	6	6	11	10	7	1,701
4	SUTA	-	1	(0)	1,557	796	(58)	(12)	18	11	4	4	6	2,327
5	Payroll Tax Projects	-	-	479	-	-	-	-	-	-	-	-	-	479
6	Ad Valorem	305,654	305,654	305,654	445,837	447,579	446,708	446,708	444,478	444,478	444,478	444,478	444,478	4,926,182
7	30105 Corp/State Franchise Tax	83,333	110,067	-	193,400	96,700	96,700	96,700	96,700	96,700	96,700	96,700	96,700	1,160,400
8	30107 City Franchise	167	167	167	167	167	167	167	167	167	167	167	167	2,000
9	30109 State Gross Receipts	48,392	78,824	118,988	132,807	112,409	93,461	58,961	38,944	36,415	37,314	35,896	38,585	830,996
10	30104 State Supv & Inspection	48,815	48,815	48,815	48,815	48,815	48,815	47,818	47,818	47,818	47,818	47,818	47,818	579,799
11	30108 Dot Transmission User Tax	-	-	-	-	-	22,479	-	-	-	-	-	-	22,479
12	Division 91 Allocations	11,256	13,239	25,763	14,499	14,853	17,797	14,353	19,917	15,565	14,749	14,963	14,560	191,516
13	Division 12 Allocations	9,347	24,655	12,814	11,955	10,266	11,713	11,650	10,340	10,941	12,361	9,533	9,334	144,910
14	Division 02 Allocations	14,759	(16,311)	22,679	38,144	14,931	17,280	17,182	15,762	16,774	21,480	16,220	15,571	194,470
15	Total	\$ 534,666	\$ 602,832	\$ 552,638	\$ 906,009	\$ 764,084	\$ 765,138	\$ 707,158	\$ 687,086	\$ 680,867	\$ 704,385	\$ 675,338	\$ 679,779	\$ 8,259,980
16														
17	<u>Division 002</u>													
18	FICA	275,931	(482,447)	467,783	316,721	307,871	372,926	373,301	340,118	363,995	445,776	350,200	341,164	3,473,337
19	FUTA	305	352	212	24,466	3,021	963	210	170	208	312	395	220	30,833
20	SUTA	467	663	418	40,666	9,225	3,074	985	(50)	527	574	727	525	57,800
21	Ad Valorem	80,400	80,400	80,400	41,200	41,200	41,200	41,200	41,200	41,200	41,200	41,200	41,200	612,000
22	30105 Corp/State Franchise Tax	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total	\$ 357,103	\$ (401,032)	\$ 548,813	\$ 423,053	\$ 361,316	\$ 418,162	\$ 415,695	\$ 381,438	\$ 405,929	\$ 487,862	\$ 392,523	\$ 383,108	\$ 4,173,971
24														
25	<u>Division 012</u>													
26	FICA	149,163	472,750	222,557	186,285	181,255	216,860	217,184	190,121	202,463	232,465	172,558	168,531	2,612,190
27	FUTA	165	196	115	14,289	1,827	556	119	94	115	161	194	108	17,939
28	SUTA	253	368	228	23,752	5,524	1,783	565	(39)	293	294	357	259	33,637
29	Ad Valorem	48,100	48,100	48,100	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	400,800
30	Total	\$ 197,681	\$ 521,413	\$ 271,000	\$ 252,826	\$ 217,105	\$ 247,699	\$ 246,368	\$ 218,676	\$ 231,372	\$ 261,419	\$ 201,608	\$ 197,398	\$ 3,064,566
31														
32	<u>Division 091</u>													
33	FICA	26,859	31,581	61,475	31,379	34,368	42,610	34,243	47,498	37,127	35,179	35,691	34,718	452,728
34	FUTA	-	8	(3)	1,602	205	(88)	17	7	4	10	9	7	1,776
35	SUTA	-	1	(0)	1,614	868	(57)	(11)	19	8	3	3	6	2,455
36	Ad Valorem	-	-	-	-	-	-	-	-	-	-	-	-	-
37	30105 Corp/State Franchise Tax	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Total	\$ 26,859	\$ 31,590	\$ 61,472	\$ 34,595	\$ 35,441	\$ 42,465	\$ 34,248	\$ 47,524	\$ 37,138	\$ 35,192	\$ 35,703	\$ 34,731	\$ 456,959

Tennessee Distribution System
Depreciation and Amortization Expense
Twelve Months Ended September 30, 2021

Line No.	Description	Reference	Amount
	(a)	(b)	(c)
1	Base period per books Depreciation Expense (1)		\$ 15,666,182
2			
3	Adjustment to Reflect Year End Plant Levels		<u>1,429,661</u>
4			
5	Total Proforma Depreciation Expense	Wp 6-2	\$ 17,095,843
6			
7	Adjustment to reflect Proposed Depreciation Rates		<u>-</u>
8			
9	Total Proforma Depreciation Expense	Wp 6-1	17,095,843
10			
11	Amortization of Deferred Pension Regulated Asset	Wp 7-3	0
12			
13	Net Elimination of Intercompany Leased Property	Wp 3-1	258,038
14			
15	Adjustment for Depreciation Expense on Capitalized Incentive Comp	Wp 7-8	<u>(178,901)</u>
16			
17	Total Depreciation and Amortization Expense, As Adjusted		<u>\$ 17,174,980</u>
18			
19	Note:		
20	1. Twelve months ended September 30, 2021		

**Tennessee Distribution System
Depreciation Expense Adjustment
Proforma SSU Depreciation at Proposed Depreciation Rates
Twelve Months Ended September 30, 2021**

Line No.	Description	Amount	Allocation	Allocated
	(a)	(b)	(c)	(d)
1	Proforma Depreciation			
2	Tennessee Operations	\$ 15,851,754	100.00%	\$ 15,851,754
3	Mid-States General Office	26,641	41.91%	11,165
4	SSU Div 12 - Customer Service	10,466,260	4.73%	494,841
5	SSU Div 02 - General Office	17,864,789	4.13%	738,083
6				
7	Proforma Depreciation Adjustment			<u>\$ 17,095,843</u>

**Tennessee Distribution System
Depreciation Expense Adjustment
Proforma SSU Depreciation at Current Depreciation Rates
Twelve Months Ended September 30, 2021**

Line No.	Description	Amount	Allocation	Allocated
	(a)	(b)	(c)	(d)
1	Proforma Depreciation			
2	Tennessee Operations	\$ 15,851,754	100.00%	\$ 15,851,754
3	Mid-States General Office	\$ 26,641	41.91%	11,165
4	SSU Div 12 - Customer Service	\$ 10,466,260	4.73%	494,841
5	SSU Div 02 - General Office	\$ 17,864,789	4.13%	738,083
6				
7	Proforma Depreciation Expense			<u>\$ 17,095,843</u>

Tennessee Distribution System
Rate Base & Return
Twelve Months Ended September 30, 2021

Line No.	Description	Historic Base Period (1)	Reference
	(a)	(b)	(c)
1	Original Cost of Plant	\$ 752,763,449	WP 7-10 WP7-2
2			
3	Accumulated Depreciation and Amortization	(236,585,801)	WP7-2
4			
5	Construction Work in Progress per Books	10,767,732	WP7-2
6			
7	Storage Gas Investment	3,804,048	WP7-2
8			
9	Cash Working Capital	1,998,664	WP 7-5
10			
11	Material & Supplies	350,937	WP7-2
12			
13	Regulatory Assets/Liabilities (EDITL & Deferral)	(23,297,122)	WP 7-9
14			
15	Accumulated Deferred Income Tax	(61,668,567)	WP 7-2
16			
17	Customer Advances for Construction	(20,280)	WP7-2
18			
19	Customer Deposits	(1,069,783)	WP7-2
20			
21	Accumulated Interest on Customer Deposits	(14,291)	WP7-2
22			
23	Unadjusted Rate Base	\$ 447,028,985	
24			
25	Adjustments:	(7,218,558)	WP 7-8
26			
27	Net Elimination of Intercompany Leased Property	\$ 6,253,167	WP7-2
28			
29	Total Rate Base	<u>\$ 446,063,594</u>	
30			
31	Return at Overall Cost of Capital on Rate Base	<u>\$ 33,588,589</u>	
32			
33	Note:		
34	1. Twelve months ended September 30, 2021		

Tennessee Distribution System
Rate Base & Return
Twelve Months Ended September 30, 2021

Line No.	Description	Historic Base Period (1)	Reference
	(a)	(b)	(c)
1	Original Cost of Plant	\$ 720,880,870	WP 7-10 WP7-2
2			
3	Accumulated Depreciation and Amortization	(230,720,030)	WP7-2
4			
5	Construction Work in Progress per Books	15,019,610	WP7-2
6			
7	Storage Gas Investment	3,804,048	WP7-2
8			
9	Cash Working Capital	1,998,664	WP 7-5
10			
11	Material & Supplies	350,937	WP7-2
12			
13	Regulatory Assets/Liabilities (EDITL & Deferral)	(25,865,420)	WP 7-9
14			
15	Accumulated Deferred Income Tax	(53,795,581)	WP 7-2
16			
17	Customer Advances for Construction	(20,280)	WP7-2
18			
19	Customer Deposits	(1,069,783)	WP7-2
20			
21	Accumulated Interest on Customer Deposits	<u>(14,291)</u>	WP7-2
22			
23	Unadjusted Rate Base	\$ 430,568,743	
24			
25	Adjustments:	(7,218,558)	WP 7-8
26			
27	Net Elimination of Intercompany Leased Property	\$ 6,382,186	WP7-2
28			
29	Total Rate Base	<u>\$ 429,732,371</u>	
30			
31	Return at Overall Cost of Capital on Rate Base	<u>\$ 32,058,035</u>	
32			
33	Note:		
34	1. Twelve months ended September 30, 2021		

WP 7-1

[illegible]

Tennessee Distribution System
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended September 30, 2021

WP 7-2

Factors										Division 093		Division 091		Division 012		CKV		Division 002		Greenville		AEAM		ALGN																					
Line No.	Month	Division 093 - Tennessee		Division 091 - Mid-States General Office		Division 012 - SSU Customer		Division 002 - SSU General		Greenville		AEAM		ALGN		FY20	100%	40.79%	4.68%	2.00%	4.16%	1.28%	5.10%	9.08%																					
	(a)	(b)	(c)	(d)	(e)	(f)	(g)			FY21	100%	41.91%	4.73%	2.11%	4.13%	1.30%	5.07%	1.26%	Total Tennessee																										
1	Gas Plant in Service (Account 101)																																												
2																																													
3	Sep-20	\$	681,907,605	\$	2,714,030	\$	133,540,878	\$	16,948,650	\$	134,787,275	\$	9,258,178	\$	28,246,300	\$	20,823,328	\$	681,907,605	\$	1,107,053	\$	6,248,128	\$	339,524	\$	5,613,382	\$	118,319	\$	1,440,196	\$	1,890,135	\$	698,664,342										
4	Oct-20		683,039,068		2,726,297		133,647,917		16,948,650		142,843,237		9,258,178		28,266,382		20,823,328		683,039,068		1,142,591		6,318,820		357,082		5,901,564		119,984		1,434,316		261,426		698,574,851										
5	Nov-20		685,721,125		2,726,297		133,646,693		16,948,650		140,126,622		9,258,178		31,805,246		21,270,439		685,721,125		1,142,591		6,318,762		357,082		5,789,327		119,984		1,613,888		267,039		701,329,798										
6	Dec-20		691,442,257				134,398,465		16,948,650		150,314,379		9,258,178		32,010,274		21,271,341		691,442,257				869,713		6,354,306		357,082		6,210,234		119,984		1,624,292		267,051		707,244,919								
7	Jan-21		694,414,529				134,400,456		16,948,650		150,204,316		9,258,178		32,246,240		21,271,232		694,414,529				869,713		6,354,400		357,082		6,205,687		119,984		1,636,265		267,049		710,224,709								
8	Feb-21		695,529,908				134,938,129		16,948,650		149,998,914		9,258,178		32,504,824		21,271,232		695,529,908				869,713		6,379,821		357,082		6,197,201		119,984		1,649,387		267,049		711,370,144								
9	Mar-21		706,649,178				134,938,696		16,948,650		150,011,667		9,258,178		32,506,774		21,271,230		706,649,178				868,861		6,379,848		357,082		6,197,728		119,984		1,649,486		267,049		722,489,215								
10	Apr-21		709,736,078				134,971,336		16,976,257		150,907,935		9,258,178		32,507,275		21,271,230		709,736,078				868,861		6,381,391		357,663		6,234,757		119,984		1,649,511		267,049		725,615,295								
11	May-21		712,306,673				135,098,021		16,999,122		151,481,823		9,258,178		32,705,520		21,271,230		712,306,673				868,861		6,387,380		358,145		6,258,467		119,984		1,659,571		267,049		728,226,131								
12	Jun-21		716,607,841				135,124,803		16,990,310		151,933,266		9,267,669		32,705,704		21,271,230		716,607,841				857,924		6,388,647		357,959		6,277,118		120,107		1,659,580		267,049		732,536,226								
13	Jul-21		722,261,915				135,124,803		16,990,310		151,954,036		9,267,669		32,705,704		21,271,230		722,261,915				857,924		6,388,647		357,959		6,277,976		120,107		1,659,580		267,049		738,191,157								
14	Aug-21		726,241,281				135,162,780		17,005,200		151,378,350		9,267,669		21,271,230		21,271,230		726,241,281				857,924		6,390,442		358,273		6,254,192		120,107		1,079,362		267,049		741,568,631								
15	Sep-21		734,575,926				135,300,137		17,015,495		151,551,930		9,267,669		34,982,672		21,271,230		734,575,926				857,924		6,396,936		358,490		6,261,363		120,107		1,775,120		267,049		750,612,915								
16	Average	\$	704,648,722	\$	2,215,379	\$	134,637,932	\$	16,970,557	\$	148,268,750	\$	9,261,099	\$	31,112,626	\$	21,202,270	\$	704,648,722	\$	926,127	\$	6,360,579	\$	356,193	\$	6,129,154	\$	119,894	\$	1,579,273	\$	391,469	\$	720,511,410										
17																																													
18	Construction Work in Process (Account 1070)																																												
19																																													
20	Sep-20	\$	14,570,613	\$	519,758	\$	1,653,501	\$	-	\$	23,789,041	\$	-	\$	-	\$	-	\$	14,570,613	\$	212,009	\$	77,364	\$	-	\$	990,724	\$	-	\$	-	\$	-	\$	-	\$	15,850,710								
21	Oct-20		16,356,846		445,238		1,573,332		-		17,532,510		-		0		0		16,356,846		186,599		74,387		-		724,355		0		0		0		0		17,342,187								
22	Nov-20		17,630,327		255,240		1,623,310		-		16,392,149		-		0		0		17,630,327		106,971		76,749		-		677,241		0		0		0		0		18,491,289								
23	Dec-20		16,072,974				778,327		-		9,125,512		-		0		0		16,072,974		326,197		44,144		-		377,020		0		0		0		0		16,820,335								
24	Jan-21		16,542,588		(608,068)		962,808		-		10,441,531		-		0		0		16,542,588		(254,841)		45,521		-		431,392		0		0		0		0		16,764,660								
25	Feb-21		17,736,777		(556,561)		451,295		-		13,251,517		-		0		0		17,736,777		(233,255)		21,337		-		547,486		0		0		0		0		18,072,345								
26	Mar-21		10,846,207		774,399		463,894		-		10,999,385		-		0		0		10,846,207		324,551		21,933		-		454,439		0		0		0		0		11,647,130								
27	Apr-21		11,451,094		509,504		541,431		-		11,756,153		-		0		0		11,451,094		213,533		25,599		-		485,705		0		0		0		0		12,175,931								
28	May-21		13,303,185		453,981		1,681,025		-		10,178,507		-		0		0		13,303,185		190,263		79,478		-		420,525		0		0		0		0		13,993,451								
29	Jun-21		14,115,825		693,923		1,908,041		-		13,260,434		-		0		0		14,115,825		290,823		90,211		-		547,854		0		0		0		0		15,044,714								
30	Jul-21		13,150,523		908,248		2,193,867		-		11,346,774		-		0		0		13,150,523		380,647		103,725		-		468,792		0		0		0		0		14,103,687								
31	Aug-21		13,319,669		428,139		2,604,319		-		13,518,891		-		0		0		13,319,669		179,433		123,131		-		558,533		0		0		0		0		14,180,765								
32	Sep-21		9,048,502		474,495		3,809,753		-		32,439,702		-		0		0		9,048,502		198,861		180,124		-		1,340,245		0		0		0		0		10,767,732								
33	Average	\$	14,165,010	\$	390,510	\$	1,569,250	\$	-	\$	14,925,547	\$	-	\$	-	\$	-	\$	14,165,010	\$	163,215	\$	74,131	\$	-	\$	617,255	\$	-	\$	-	\$	-	\$	-	\$	15,019,610								

Tennessee Distribution System
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended September 30, 2021

WP 7-2

		Factors										Division 093		Division 091		Division 012		CKV		Division 002		Greenville		AEAM		ALGN									
		FY20		100%		40.79%		4.68%		2.00%		4.16%		1.28%		5.10%		9.08%																	
Line No.	Month	Division 093 - Tennessee	Division 091 - Mid-States General Office	Division 012 - SSU Customer	CKV	Division 002 - SSU General	Greenville	AEAM	ALGN	FY21	100%	41.91%	4.73%	2.11%	4.13%	1.30%	5.07%	1.26%	Total Tennessee																
	(a)	(b)	(c)	(d)	(e)	(f)	(g)				(h)	(i)	(j)	(k)	(l)	(m)			(n)																
69																																			
70	Customers Deposits (Account 2350)																																		
71																																			
72	Sep-20	\$	(1,138,262)	\$	-	\$	-	\$	-	\$	(1,138,262)	\$	-	\$	-	\$	-	\$	-	\$	(1,138,262)														
73	Oct-20		(1,119,610)		-		-	0	0	0	(1,119,610)	0	0	0	0	0	0	0	0	0	(1,119,610)														
74	Nov-20		(1,119,112)		-		-	0	0	0	(1,119,112)	0	0	0	0	0	0	0	0	0	(1,119,112)														
75	Dec-20		(1,079,292)		-		-	0	0	0	(1,079,292)	0	0	0	0	0	0	0	0	0	(1,079,292)														
76	Jan-21		(1,044,793)		-		-	0	0	0	(1,044,793)	0	0	0	0	0	0	0	0	0	(1,044,793)														
77	Feb-21		(1,041,936)		-		-	0	0	0	(1,041,936)	0	0	0	0	0	0	0	0	0	(1,041,936)														
78	Mar-21		(1,049,205)		-		-	0	0	0	(1,049,205)	0	0	0	0	0	0	0	0	0	(1,049,205)														
79	Apr-21		(1,033,564)		-		-	0	0	0	(1,033,564)	0	0	0	0	0	0	0	0	0	(1,033,564)														
80	May-21		(1,041,964)		-		-	0	0	0	(1,041,964)	0	0	0	0	0	0	0	0	0	(1,041,964)														
81	Jun-21		(1,044,754)		-		-	0	0	0	(1,044,754)	0	0	0	0	0	0	0	0	0	(1,044,754)														
82	Jul-21		(1,056,212)		-		-	0	0	0	(1,056,212)	0	0	0	0	0	0	0	0	0	(1,056,212)														
83	Aug-21		(1,079,291)		-		-	0	0	0	(1,079,291)	0	0	0	0	0	0	0	0	0	(1,079,291)														
84	Sep-21		(1,059,185)		-		-	0	0	0	(1,059,185)	0	0	0	0	0	0	0	0	0	(1,059,185)														
85	Average	\$	(1,069,783)	\$	-	\$	-	\$	-	\$	(1,069,783)	\$	-	\$	-	\$	-	\$	-	\$	(1,069,783)														
86																																			
87																																			
88	Accumulated Deferred FTT (Total Accounts 1900, 2820, 2830)																																		
89																																			
90	Sep-20	\$	(69,664,870)	\$	(4,362,788)	\$	(14,865,719)	\$	-	\$	624,891,109	\$	-	\$	-	\$	-	\$	-	\$	(69,664,870)	\$	(1,779,581)	\$	(695,539)	\$	-	\$	26,024,359	\$	-	\$	-	\$	(46,115,632)
91	Oct-20		(69,684,580)		(4,362,788)		(14,865,719)		-		613,922,401		-		-		-		0		25,364,186		(702,845)		0		0	0	0	0	0	0	(46,851,684)		
92	Nov-20		(69,704,290)		(4,362,788)		(14,865,719)		-		616,008,110		-		-		-		0		25,450,357		(702,845)		0		0	0	0	0	0	0	(46,785,223)		
93	Dec-20		(71,689,870)		(4,494,765)		(15,084,117)		-		596,772,936		-		-		-		0		24,655,656		(1,883,756)		0		0	0	0	0	0	0	(49,631,141)		
94	Jan-21		(71,709,580)		(4,494,765)		(15,084,117)		-		584,799,758		-		-		-		0		24,160,984		(1,883,756)		0		0	0	0	0	0	0	(50,145,522)		
95	Feb-21		(71,729,290)		(4,494,765)		(15,084,117)		-		570,541,234		-		-		-		0		23,571,894		(1,883,756)		0		0	0	0	0	0	0	(50,754,323)		
96	Mar-21		(75,417,107)		(4,657,720)		(14,605,774)		-		500,554,764		-		-		-		0		20,680,405		(1,952,050)		0		0	0	0	0	0	0	(57,379,308)		
97	Apr-21		(75,550,239)		(4,657,720)		(14,605,774)		-		507,871,815		-		-		-		0		20,982,709		(1,952,050)		0		0	0	0	0	0	0	(57,210,135)		
98	May-21		(75,683,370)		(4,657,720)		(14,605,774)		-		510,572,072		-		-		-		0		21,094,270		(1,952,050)		0		0	0	0	0	0	0	(57,231,706)		
99	Jun-21		(76,927,543)		(4,782,964)		(14,171,116)		-		508,625,455		-		-		-		0		21,013,845		(2,004,540)		0		0	0	0	0	0	0	(58,588,243)		
100	Jul-21		(77,060,675)		(4,782,964)		(14,171,116)		-		515,730,554		-		-		-		0		21,307,392		(2,004,540)		0		0	0	0	0	0	0	(58,427,827)		
101	Aug-21		(77,193,806)		(4,782,964)		(14,171,116)		-		515,917,239		-		-		-		0		21,315,105		(2,004,540)		0		0	0	0	0	0	0	(58,553,246)		
102	Sep-21		(81,687,528)		(4,820,265)		(14,654,092)		-		550,211,543		-		-		-		0		22,731,973		(2,020,173)		0		0	0	0	0	0	0	(61,668,567)		
103	Average	\$	(74,130,981)	\$	(4,593,460)	\$	(14,679,559)	\$	-	\$	555,109,153	\$	-	\$	-	\$	-	\$	-	\$	(74,130,981)	\$	(1,921,360)	\$	(693,482)	\$	-	\$	22,950,241	\$	-	\$	-	\$	(53,795,581)

NP 7-2

		Factors		Division 093		Division 091		Division 012		CKV		Division 002		Greenville		AEAM		ALGN	
		FY20		100%		40.79%		4.68%		2.00%		4.16%		1.28%		5.10%		9.08%	
Line No.	Month	Division 093 - Tennessee	Division 091 - Mid-States General Office	Division 012 - SSU Customer	CKV	Division 002 - SSU General	Greenville	AEAM	ALGN	FY21	100%	41.91%	4.73%	2.11%	4.13%	1.30%	5.07%	1.26%	Total Tennessee
	(a)	(b)	(c)	(d)	(e)	(f)	(g)				(h)	(i)	(j)	(k)	(l)	(m)			(n)
104																			
105	Accumulated Depreciation (Account 1080)																		
106																			
107	Sep-20	\$ (219,109,839)	\$ (1,066,700)	\$ (56,470,820)	\$ (4,602,223)	\$ (57,538,247)	\$ (4,281,124)	\$ (15,770,532)	\$ (6,554,161)	\$	\$ (219,109,839)	\$ (435,107)	\$ (2,642,164)	\$ (92,194)	\$ (2,396,251)	\$ (54,712)	\$ (804,093)	\$ (594,922)	\$ (226,129,282)
108	Oct-20	\$ (219,398,336)	\$ (1,069,719)	\$ (57,154,368)	\$ (4,649,465)	\$ (58,316,081)	\$ (4,304,826)	\$ (15,933,036)	\$ (6,670,302)	\$	\$ (219,398,336)	\$ (448,319)	\$ (2,702,236)	\$ (97,957)	\$ (2,409,327)	\$ (55,790)	\$ (808,487)	\$ (83,742)	\$ (226,004,194)
109	Nov-20	\$ (220,257,825)	\$ (1,072,738)	\$ (57,837,911)	\$ (4,696,707)	\$ (59,071,776)	\$ (4,328,528)	\$ (16,108,356)	\$ (6,787,776)	\$	\$ (220,257,825)	\$ (449,584)	\$ (2,734,553)	\$ (98,952)	\$ (2,440,549)	\$ (56,097)	\$ (817,384)	\$ (85,217)	\$ (226,940,161)
110	Dec-20	\$ (221,187,274)	\$ (413,684)	\$ (58,524,417)	\$ (4,743,946)	\$ (59,811,327)	\$ (4,352,229)	\$ (16,284,483)	\$ (6,905,252)	\$	\$ (221,187,274)	\$ (173,375)	\$ (2,767,011)	\$ (99,948)	\$ (2,471,103)	\$ (56,404)	\$ (826,321)	\$ (86,692)	\$ (227,668,127)
111	Jan-21	\$ (222,165,071)	\$ (416,278)	\$ (59,210,930)	\$ (4,791,200)	\$ (60,617,706)	\$ (4,375,931)	\$ (16,461,467)	\$ (7,022,729)	\$	\$ (222,165,071)	\$ (174,462)	\$ (2,799,469)	\$ (100,943)	\$ (2,504,419)	\$ (56,711)	\$ (835,301)	\$ (88,167)	\$ (228,724,543)
112	Feb-21	\$ (222,601,726)	\$ (418,776)	\$ (59,899,807)	\$ (4,838,445)	\$ (61,418,682)	\$ (4,399,633)	\$ (16,639,508)	\$ (7,140,205)	\$	\$ (222,601,726)	\$ (175,509)	\$ (2,832,039)	\$ (101,938)	\$ (2,537,511)	\$ (57,018)	\$ (844,336)	\$ (89,642)	\$ (229,339,719)
113	Mar-21	\$ (223,573,382)	\$ (419,136)	\$ (60,588,687)	\$ (4,885,669)	\$ (62,212,260)	\$ (4,423,334)	\$ (16,817,558)	\$ (7,257,682)	\$	\$ (223,573,382)	\$ (175,660)	\$ (2,864,609)	\$ (102,933)	\$ (2,570,298)	\$ (57,326)	\$ (853,371)	\$ (91,116)	\$ (230,288,694)
114	Apr-21	\$ (224,663,176)	\$ (421,530)	\$ (61,277,676)	\$ (4,932,999)	\$ (62,987,470)	\$ (4,447,036)	\$ (16,995,612)	\$ (7,375,158)	\$	\$ (224,663,176)	\$ (176,663)	\$ (2,897,184)	\$ (103,931)	\$ (2,602,325)	\$ (57,633)	\$ (862,405)	\$ (92,591)	\$ (231,455,909)
115	May-21	\$ (225,652,089)	\$ (423,924)	\$ (61,967,079)	\$ (4,980,596)	\$ (63,755,695)	\$ (4,470,737)	\$ (17,174,956)	\$ (7,492,634)	\$	\$ (225,652,089)	\$ (177,667)	\$ (2,929,779)	\$ (104,933)	\$ (2,634,065)	\$ (57,940)	\$ (871,506)	\$ (94,066)	\$ (232,522,044)
116	Jun-21	\$ (226,746,079)	\$ (400,061)	\$ (62,662,660)	\$ (5,019,272)	\$ (64,536,232)	\$ (4,494,415)	\$ (17,356,045)	\$ (7,610,352)	\$	\$ (226,746,079)	\$ (167,666)	\$ (2,962,666)	\$ (105,748)	\$ (2,666,312)	\$ (58,247)	\$ (880,695)	\$ (95,544)	\$ (233,682,957)
117	Jul-21	\$ (227,665,924)	\$ (402,295)	\$ (63,372,372)	\$ (5,066,457)	\$ (65,335,773)	\$ (4,517,952)	\$ (17,540,882)	\$ (7,728,074)	\$	\$ (227,665,924)	\$ (168,602)	\$ (2,996,220)	\$ (106,742)	\$ (2,699,345)	\$ (58,552)	\$ (890,074)	\$ (97,022)	\$ (234,682,482)
118	Aug-21	\$ (228,339,839)	\$ (404,528)	\$ (64,082,368)	\$ (5,113,753)	\$ (66,119,330)	\$ (4,541,490)	\$ (17,746,411)	\$ (7,845,796)	\$	\$ (228,339,839)	\$ (169,538)	\$ (3,029,789)	\$ (107,739)	\$ (2,731,718)	\$ (58,857)	\$ (900,503)	\$ (98,500)	\$ (235,436,482)
119	Sep-21	\$ (229,406,526)	\$ (406,762)	\$ (64,794,537)	\$ (5,161,579)	\$ (66,923,129)	\$ (4,565,028)	\$ (17,983,381)	\$ (7,963,518)	\$	\$ (229,406,526)	\$ (170,474)	\$ (3,063,460)	\$ (108,746)	\$ (2,764,927)	\$ (59,162)	\$ (912,528)	\$ (99,978)	\$ (236,585,801)
120	Average	\$ (223,905,160)	\$ (564,318)	\$ (60,603,356)	\$ (4,883,255)	\$ (62,203,362)	\$ (4,423,251)	\$ (16,831,710)	\$ (7,257,972)	\$	\$ (223,905,160)	\$ (235,587)	\$ (2,863,168)	\$ (102,516)	\$ (2,571,396)	\$ (57,265)	\$ (854,385)	\$ (130,554)	\$ (230,720,030)
121																			
122																			
123	Customers Advances (Account 2520)																		
124																			
125	Sep-20	\$ (20,280)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$	\$ (20,280)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (20,280)
126	Oct-20	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
127	Nov-20	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
128	Dec-20	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
129	Jan-21	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
130	Feb-21	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
131	Mar-21	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
132	Apr-21	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
133	May-21	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
134	Jun-21	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
135	Jul-21	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
136	Aug-21	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
137	Sep-21	\$ (20,280)	-	-	-	-	-	-	-	\$	\$ (20,280)	0	0	0	0	0	0	0	\$ (20,280)
138	Average	\$ (20,280)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$	\$ (20,280)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (20,280)

NP 7-2

		Factors										Division 093		Division 091		Division 012		CKV		Division 002		Greenville		AEAM		ALGN	
		FY20		100%		40.79%		4.68%		2.00%		4.16%		1.28%		5.10%		9.08%									
Line No.	Month	Division 093 - Tennessee	Division 091 - Mid-States General Office	Division 012 - SSU Customer	CKV	Division 002 - SSU General	Greenville	AEAM	ALGN	FY21	100%	41.91%	4.73%	2.11%	4.13%	1.30%	5.07%	1.26%	Total Tennessee								
	(a)	(b)	(c)	(d)	(e)	(f)	(g)				(h)	(i)	(j)	(k)	(l)	(m)			(n)								
139	Interest on Customer Deposits (Account 2370-26919)																										
141																											
142	Sep-20	\$ (20,060)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (20,060)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (20,060)								
143	Oct-20	(20,277)	-	-	-	-	0	0	0	(20,277)	0	0	0	0	0	0	0	0	(20,277)								
144	Nov-20	(20,621)	-	-	-	-	0	0	0	(20,621)	0	0	0	0	0	0	0	0	(20,621)								
145	Dec-20	(20,960)	-	-	-	-	0	0	0	(20,960)	0	0	0	0	0	0	0	0	(20,960)								
146	Jan-21	(21,972)	-	-	-	-	0	0	0	(21,972)	0	0	0	0	0	0	0	0	(21,972)								
147	Feb-21	(23,417)	-	-	-	-	0	0	0	(23,417)	0	0	0	0	0	0	0	0	(23,417)								
148	Mar-21	(2,793)	-	-	-	-	0	0	0	(2,793)	0	0	0	0	0	0	0	0	(2,793)								
149	Apr-21	(4,907)	-	-	-	-	0	0	0	(4,907)	0	0	0	0	0	0	0	0	(4,907)								
150	May-21	(7,012)	-	-	-	-	0	0	0	(7,012)	0	0	0	0	0	0	0	0	(7,012)								
151	Jun-21	(8,816)	-	-	-	-	0	0	0	(8,816)	0	0	0	0	0	0	0	0	(8,816)								
152	Jul-21	(10,539)	-	-	-	-	0	0	0	(10,539)	0	0	0	0	0	0	0	0	(10,539)								
153	Aug-21	(11,752)	-	-	-	-	0	0	0	(11,752)	0	0	0	0	0	0	0	0	(11,752)								
154	Sep-21	(12,658)	-	-	-	-	0	0	0	(12,658)	0	0	0	0	0	0	0	0	(12,658)								
155	Average	\$ (14,291)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (14,291)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (14,291)								
156																											
157	Net elimination of intercompany leased property																										
158																											
159																											
160	Sep-20	\$ 6,511,205	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6,511,205	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6,511,205								
161	Oct-20	6,489,702	-	-	-	-	0	0	0	6,489,702	0	0	0	0	0	0	0	0	6,489,702								
162	Nov-20	6,468,199	-	-	-	-	0	0	0	6,468,199	0	0	0	0	0	0	0	0	6,468,199								
163	Dec-20	6,446,695	-	-	-	-	0	0	0	6,446,695	0	0	0	0	0	0	0	0	6,446,695								
164	Jan-21	6,425,192	-	-	-	-	0	0	0	6,425,192	0	0	0	0	0	0	0	0	6,425,192								
165	Feb-21	6,403,689	-	-	-	-	0	0	0	6,403,689	0	0	0	0	0	0	0	0	6,403,689								
166	Mar-21	6,382,186	-	-	-	-	0	0	0	6,382,186	0	0	0	0	0	0	0	0	6,382,186								
167	Apr-21	6,360,683	-	-	-	-	0	0	0	6,360,683	0	0	0	0	0	0	0	0	6,360,683								
168	May-21	6,339,180	-	-	-	-	0	0	0	6,339,180	0	0	0	0	0	0	0	0	6,339,180								
169	Jun-21	6,317,676	-	-	-	-	0	0	0	6,317,676	0	0	0	0	0	0	0	0	6,317,676								
170	Jul-21	6,296,173	-	-	-	-	0	0	0	6,296,173	0	0	0	0	0	0	0	0	6,296,173								
171	Aug-21	6,274,670	-	-	-	-	0	0	0	6,274,670	0	0	0	0	0	0	0	0	6,274,670								
172	Sep-21	6,253,167	-	-	-	-	0	0	0	6,253,167	0	0	0	0	0	0	0	0	6,253,167								
173	Average	\$ 6,382,186	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6,382,186	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6,382,186								

**Tennessee Distribution System
Pension Regulated Asset
Twelve Months Ended September 30, 2021**

Line No.				
1	Annual benchmark per Docket 12-00064	2,086,819		
2	Quarterly benchmark	521,705		
3				
4		Contribution	Benchmark	Difference
5	Quarter ended 3/31/13	521,705	521,705	-
6	Quarter ended 6/30/13	641,911	521,705	120,206
7	Quarter ended 9/30/13	1,038,413	521,705	516,708
8	Quarter ended 12/31/13	417,671	521,705	(104,034)
9	Quarter ended 3/30/14	390,181	521,705	(131,524)
10	Quarter ended 6/30/14	1,418,839	521,705	897,134
11		\$ 4,428,719	\$ 3,130,229	\$ 1,298,490
12				
13	Monthly Amortization			
14	2 years amortization		\$	54,104
15				
16		Amortization Expense	Regulated Asset Balance	
17	Sep-15		1,082,075	
18	Oct-15	54,104	1,027,971	
19	Nov-15	54,104	973,868	
20	Dec-15	54,104	919,764	
21	Jan-16	54,104	865,660	
22	Feb-16	54,104	811,556	
23	Mar-16	54,104	757,453	
24	Apr-16	54,104	703,349	
25	May-16	54,104	649,245	
26	Jun-16	54,104	595,141	
27	Jul-16	54,104	541,038	
28	Aug-16	54,104	486,934	
29	Sep-16	54,104	432,830	
30	Oct-16	54,104	378,726	
31	Nov-16	54,104	324,623	
32	Dec-16	54,104	270,519	
33	Jan-17	54,104	216,415	
34	Feb-17	54,104	162,311	
35	Mar-17	54,104	108,208	
36	Apr-17	54,104	54,104	
37	May-17	54,104	-	
38	Jun-17	-	-	
39	Jul-17	-	-	
40	Aug-17	-	-	
41	Sep-17	-	-	
42	Oct-17	-	-	
43	Nov-17	-	-	
44	Dec-17	-	-	
45	Jan-18	-	-	
46	Feb-18	-	-	
47	Mar-18	-	-	
48	Apr-18	-	-	
49	May-18	-	-	
50	Jun-18	-	-	
51	Jul-18	-	-	
52	Aug-18	-	-	
53	Sep-18	-	-	
54	Oct-18	-	-	
55	Nov-18	-	-	
56	Dec-18	-	-	
57	Jan-19	-	-	
58	Feb-19	-	-	
59	Mar-19	-	-	
60	Apr-19	-	-	
61	May-19	-	-	
62	Jun-19	-	-	
63	Jul-19	-	-	
64	Aug-19	-	-	
65	Sep-19	-	-	
66	Oct-19	-	-	
67	Nov-19	-	-	
68	Dec-19	-	-	
69	Jan-20	-	-	
70	Feb-20	-	-	
71	Mar-20	-	-	
72	Apr-20	-	-	
73	May-20	-	-	
74	Jun-20	-	-	
75	Jul-20	-	-	
76	Aug-20	-	-	
77	Sep-20	-	-	
78	Oct-20	-	-	
79	Nov-20	-	-	
80	Dec-20	-	-	
81	Jan-21	-	-	
82	Feb-21	-	-	
83	Mar-21	-	-	
84	Apr-21	-	-	
85	May-21	-	-	
86	Jun-21	-	-	
87	Jul-21	-	-	
88	Aug-21	-	-	
89	Sep-21	-	-	
90	Annual Amortization	\$ -	\$ -	13 month average

**Tennessee Distribution System
Accumulated Deferred Income Tax
Shared Services Division 002
Twelve Months Ended September 30, 2021**

Line No.	Month	Total SSU 002	Non-regulated NOL[1]	Regulated Utility NOL	Other ADIT	SSU Utility ADIT
	(a)	(b)	(c)	(d)	(e)	(f)
1	Sep-20	463,296,368	(161,594,741)	608,544,074	16,347,035	624,891,109
2	Oct-20	452,327,660	(161,594,741)	608,544,074	5,378,327	613,922,401
3	Nov-20	454,413,369	(161,594,741)	608,544,074	7,464,036	616,008,110
4	Dec-20	434,148,449	(162,624,487)	598,045,312	(1,272,376)	596,772,936
5	Jan-21	422,175,271	(162,624,487)	598,045,312	(13,245,554)	584,799,758
6	Feb-21	407,916,747	(162,624,487)	598,045,312	(27,504,078)	570,541,234
7	Mar-21	336,605,904	(163,948,860)	537,424,569	(36,869,805)	500,554,764
8	Apr-21	343,922,955	(163,948,860)	537,424,569	(29,552,754)	507,871,815
9	May-21	346,623,212	(163,948,860)	537,424,569	(26,852,497)	510,572,072
10	Jun-21	343,475,023	(165,150,432)	530,205,732	(21,580,277)	508,625,455
11	Jul-21	350,580,122	(165,150,432)	530,205,732	(14,475,178)	515,730,554
12	Aug-21	350,766,807	(165,150,432)	530,205,732	(14,288,493)	515,917,239
13	Sep-21	384,911,081	(165,300,462)	574,342,040	(24,130,497)	550,211,543
14						
15						
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33						

[1] FD - NOL Credit Carryforward - Non Reg

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Twelve Months Ended September 30, 2021

Line No.		Base Period
1	Revenue Lag	37.50
2		
3	Expense Lag	32.41
4		
5	Net Lag	5.09
6		
7	Daily Cost of Service	393,013
8		
9	Cash Working Capital	1,998,664

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Twelve Months Ended September 30, 2021

Line No.	Description	Attrition Year Expenses	Expense Lag	CWC Requirement (b) x (c)
	(a)	(b)	(c)	(d)
1	Gas Supply Expense			
2	Purchased Gas			
3				
4	Operation and Maintenance Expense			
5	O&M, Labor			
6	O&M, Non-Labor			
7	Total O&M Expense			
8				
9				
10	Taxes Other Than Income			
11	Ad Valorem			
12	State Gross Receipts Tax			
13	Payroll Taxes			
14	Franchise Tax			
15	TRA Inspection Fee			
16	DOT			
17				
18	Allocated Taxes-Shared Services			
19	Ad Valorem	0%		
20	Payroll Taxes	0%		
21				
22	Allocated Taxes-Business Unit			
23	Ad Valorem	0%		
24	Payroll Taxes	0%		
25	Total Taxes Other Than Income			
26				
27	Federal Income Tax			
28	Current Taxes			
29	Deferred Taxes			
30				
31	State Excise Tax			
32	Current Taxes			
33	Deferred Taxes			
34				
35	Depreciation			
36				
37	Interest on Customer Deposits			
38				
39	Interest Expense - LTD			
40				
41	Interest Expense - STD			
42				
43	Return on Equity			
44				
45				
46	TOTAL			
47				
48	Daily Cost of Service			
49				
50				

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Twelve Months Ended September 30, 2021

Line No.	Description	Histori Base Period	Expense Lag	CWC Requirement (b) x (c)
	(a)	(b)	(c)	(d)
1	Gas Supply Expense			
2	Purchased Gas	55,628,730	39.33	2,187,877,949
3				
4	Operation and Maintenance Expense			
5	O&M, Labor	8,073,046	14.07	113,587,763
6	O&M, Non-Labor	14,274,725	29.45	420,390,661
7	Total O&M Expense	22,347,772		533,978,424
8				
9				
10	Taxes Other Than Income			
11	Ad Valorem	4,961,570	241.50	1,198,219,252
12	State Gross Receipts Tax	830,996	(151.50)	(125,895,914)
13	Payroll Taxes	207,228	15.21	3,150,916
14	Franchise Tax	1,162,400	37.50	43,590,002
15	TRA Inspection Fee	579,799	272.50	157,995,151
16	DOT	22,479	59.00	1,326,266
17				
18	Allocated Taxes-Shared Services			
19	Ad Valorem	0% -	241.50	-
20	Payroll Taxes	100% 339,380	15.21	5,160,293
21				
22	Allocated Taxes-Business Unit			
23	Ad Valorem	0% -	241.50	-
24	Payroll Taxes	100% 191,516	15.21	2,912,011
25	Total Taxes Other Than Income	8,295,367		1,286,457,977
26				
27	Federal Income Tax	6,094,032		
28	Current Taxes	-	37.50	-
29	Deferred Taxes	6,094,032	-	-
30				
31	State Excise Tax	2,017,377		
32	Current Taxes	-	37.50	-
33	Deferred Taxes	2,017,377	-	-
34				
35	Depreciation	15,924,220	-	-
36				
37	Interest on Customer Deposits	34,768	182.50	6,345,150
38				
39	Interest Expense - LTD	6,913,986	91.25	630,901,196
40				
41	Interest Expense - STD	178,425	24.05	4,290,894
42				
43	Return on Equity	26,015,029		-
44				
45				
46	TOTAL	143,449,706	32.41	4,649,851,591
47				
48	Daily Cost of Service	393,013		12,739,319
49				
50				

Tennessee Distribution System
Amortization Schedule of Capitalized Incentive Compensation & SERP Adjustments
For the Twelve Months Ended September 30, 2021

Line No.	Description	Amounts	Amounts
1	(a)	(b)	(c)
2	<u>Forward Looking Test Year</u>	Rate Base	Depreciation Expense
3			
4			
5			
6			
7			
8			
9			
10		\$ -	\$ -
11	<u>Historic Base Period</u>		
12	Docket No. 16-00013, 2016 TN ARM Amortization Schedule of Capitalized Incentive Compensation Adjustment, TYE 5-31-16	\$ 1,072,672	\$ 29,796
13	Docket No. 17-00012, 2017 TN ARM Amortization Schedule of Capitalized Incentive Compensation Adjustment, TYE 9-30-17	1,164,018	29,847
14	Docket No. 18-00067, 2018 TN ARM Amortization Schedule of Capitalized Incentive Compensation Adjustment, TYE 9-30-18	917,551	22,939
15	Docket No. 19-00076, 2019 TN ARM Amortization Schedule of Capitalized Incentive Compensation Adjustment, TYE 9-30-19	1,001,202	24,420
16	Docket No. 21-00019, 2020 TN ARM Amortization Schedule of Capitalized Incentive Compensation Adjustment, TYE 9-30-20	1,200,741	28,589
17	Docket No. 22-00010, 2021 TN ARM Amortization Schedule of Capitalized Incentive Compensation & SERP Adjustments, TYE 9-30-21	1,862,373	43,311
18	Total	\$ 7,218,558	\$ 178,901
19			
20			
21			
22	*Historic Base Period Amounts for the period of 2021		

**Tennessee Distribution System
Deferred Regulatory Liability Amortization**

WP 7-9

Date Rates Last Set:	6/1/2019	Reg Liability Currently in Rates:	29,024,530	Current Amortization Period (Years):	28
Date of Next Rate Implementation:	3/1/2021	Final Reg Liability	29,337,265	Final Amortization Period:	29
Final Amortization Month:	9/30/2047	Unprotected Balance:	18,853,052	Unprotected Amortization Period:	3
		Protected Balance:	10,484,213	Max. Monthly Protected Amortization \$	30,127

	Liability			Amortization				GL Balance Div 093			
	Protected Balance	Unprotected Balance	Total Reg Liability Balance	Protected	Unprotected	Accelerated Unprotected	Total Amortization	Cumulative Amortization - Amortization	Accts 2420- 27909, 2530- 27909	Reg liab vs GL diff	Total Reg Liab.
Beginning	(9,888,366)	(17,784,704)	(27,673,070)								
Amortized Through 5/31/21											
10/31/2018	(9,858,239)	(17,732,471)	(27,590,710)	(30,127)	(52,233)		(82,360)	(82,360)			(27,673,070)
11/30/2018	(9,828,112)	(17,680,237)	(27,508,349)	(30,127)	(52,233)		(82,360)	(164,721)			(27,673,070)
12/31/2018	(9,797,985)	(17,628,004)	(27,425,989)	(30,127)	(52,233)		(82,360)	(247,081)			(27,673,070)
1/31/2019	(9,767,858)	(17,575,771)	(27,343,629)	(30,127)	(52,233)		(82,360)	(329,441)			(27,673,070)
2/28/2019	(9,737,731)	(17,523,537)	(27,261,268)	(30,127)	(52,233)		(82,360)	(411,802)			(27,673,070)
3/31/2019	(9,707,604)	(17,471,304)	(27,178,908)	(30,127)	(52,233)		(82,360)	(494,162)			(27,673,070)
4/30/2019	(9,677,477)	(17,419,071)	(27,096,548)	(30,127)	(52,233)		(82,360)	(576,522)			(27,673,070)
5/31/2019	(9,647,350)	(17,366,837)	(27,014,187)	(30,127)	(52,233)		(82,360)	(658,883)			(27,673,070)
Adj. with 6/1/2019 Implementation	(482,915)	(868,545)	(1,351,460)								(1,351,460)
6/30/2019	(10,100,138)	(18,179,127)	(28,279,265)	(30,127)	(56,256)		(86,383)	(745,265)			(29,024,530)
7/31/2019	(10,070,011)	(18,122,871)	(28,192,882)	(30,127)	(56,256)		(86,383)	(831,648)			(29,024,530)
8/31/2019	(10,039,884)	(18,066,616)	(28,106,500)	(30,127)	(56,256)		(86,383)	(918,030)			(29,024,530)
9/30/2019	(10,009,757)	(18,010,360)	(28,020,117)	(30,127)	(56,256)		(86,383)	(1,004,413)	(28,331,420)	311,302	(29,024,530)
10/31/2019	(9,979,630)	(17,954,105)	(27,933,735)	(30,127)	(56,256)		(86,383)	(1,090,795)	(28,249,059)	315,325	(29,024,530)
11/30/2019	(9,949,503)	(17,897,849)	(27,847,352)	(30,127)	(56,256)		(86,383)	(1,177,178)	(28,166,699)	319,347	(29,024,530)
12/31/2019	(9,919,376)	(17,841,594)	(27,760,970)	(30,127)	(56,256)		(86,383)	(1,263,560)	(28,072,272)	311,302	(29,024,530)
1/31/2020	(9,889,249)	(17,785,338)	(27,674,587)	(30,127)	(56,256)		(86,383)	(1,349,943)	(27,985,890)	311,302	(29,024,530)
2/29/2020	(9,859,122)	(17,729,083)	(27,588,205)	(30,127)	(56,256)		(86,383)	(1,436,325)	(27,899,507)	311,302	(29,024,530)
3/31/2020	(9,828,995)	(17,672,827)	(27,501,822)	(30,127)	(56,256)		(86,383)	(1,522,708)	(27,813,125)	311,303	(29,024,530)
4/30/2020	(9,798,868)	(17,616,572)	(27,415,440)	(30,127)	(56,256)		(86,383)	(1,609,090)	(27,726,742)	311,303	(29,024,530)
5/31/2020	(9,768,741)	(17,560,316)	(27,329,057)	(30,127)	(56,256)		(86,383)	(1,695,473)	(27,640,360)	311,303	(29,024,530)
6/30/2020	(9,738,614)	(17,504,060)	(27,242,674)	(30,127)	(56,256)		(86,383)	(1,781,856)	(27,553,977)	311,302	(29,024,530)
7/31/2020	(9,708,487)	(17,447,805)	(27,156,292)	(30,127)	(56,256)		(86,383)	(1,868,238)	(27,467,594)	311,302	(29,024,530)
8/31/2020	(9,678,360)	(17,391,549)	(27,069,909)	(30,127)	(56,256)		(86,383)	(1,954,621)	(27,381,212)	311,302	(29,024,530)
9/30/2020	(9,648,233)	(17,335,294)	(26,983,527)	(30,127)	(56,256)		(86,383)	(2,041,003)	(27,294,830)	311,303	(29,024,530)
10/31/2020	(9,618,106)	(17,279,038)	(26,897,144)	(30,127)	(56,256)		(86,383)	(2,127,386)	(27,208,447)	311,303	(29,024,530)
11/30/2020	(9,587,979)	(17,222,783)	(26,810,762)	(30,127)	(56,256)		(86,383)	(2,213,768)	(27,122,065)	311,303	(29,024,530)
12/31/2020	(9,557,852)	(17,166,527)	(26,724,379)	(30,127)	(56,256)		(86,383)	(2,300,151)	(27,035,681)	311,302	(29,024,530)
1/31/2021	(9,527,725)	(17,110,272)	(26,637,997)	(30,127)	(56,256)		(86,383)	(2,386,533)	(26,949,298)	311,302	(29,024,530)
2/28/2021	(9,497,598)	(17,054,016)	(26,551,614)	(30,127)	(56,256)		(86,383)	(2,472,916)	(26,862,916)	311,302	(29,024,530)
Adj. with 3/1/2021 Implementation	(112,932)	(199,803)	(312,735)								(312,735)
3/31/2021	(9,580,403)	(16,774,546)	(26,354,949)	(30,127)		(479,273)	(509,400)	(2,982,316)	(26,353,518)	(1,432)	(29,337,265)
4/30/2021	(9,550,276)	(16,295,274)	(25,845,550)	(30,127)		(479,273)	(509,400)	(3,491,715)	(25,844,118)	(1,432)	(29,337,265)
5/31/2021	(9,520,149)	(15,816,001)	(25,336,150)	(30,127)		(479,273)	(509,400)	(4,001,115)	(25,334,718)	(1,432)	(29,337,265)
6/30/2021	(9,490,022)	(15,336,728)	(24,826,750)	(30,127)		(479,273)	(509,400)	(4,510,515)	(24,825,317)	(1,433)	(29,337,265)
7/31/2021	(9,459,895)	(14,857,455)	(24,317,350)	(30,127)		(479,273)	(509,400)	(5,019,915)	(24,315,918)	(1,433)	(29,337,265)
8/31/2021	(9,429,768)	(14,378,183)	(23,807,951)	(30,127)		(479,273)	(509,400)	(5,529,314)	(23,806,518)	(1,433)	(29,337,265)
9/30/2021	(9,399,641)	(13,898,910)	(23,298,551)	(30,127)		(479,273)	(509,400)	(6,038,714)	(23,297,122)	(1,429)	(29,337,265)
10/31/2021	(9,369,514)	(13,419,637)	(22,789,151)	(30,127)		(479,273)	(509,400)	(6,548,114)			(29,337,265)
11/30/2021	(9,339,387)	(12,940,364)	(22,279,751)	(30,127)		(479,273)	(509,400)	(7,057,514)			(29,337,265)
12/31/2021	(9,309,260)	(12,461,092)	(21,770,351)	(30,127)		(479,273)	(509,400)	(7,566,914)			(29,337,265)
1/31/2022	(9,279,133)	(11,981,819)	(21,260,952)	(30,127)		(479,273)	(509,400)	(8,076,313)			(29,337,265)
2/28/2022	(9,249,006)	(11,502,546)	(20,751,552)	(30,127)		(479,273)	(509,400)	(8,585,713)			(29,337,265)
3/31/2022	(9,218,879)	(11,023,273)	(20,242,152)	(30,127)		(479,273)	(509,400)	(9,095,113)			(29,337,265)
4/30/2022	(9,188,751)	(10,544,001)	(19,732,752)	(30,127)		(479,273)	(509,400)	(9,604,513)			(29,337,265)
5/31/2022	(9,158,624)	(10,064,728)	(19,223,352)	(30,127)		(479,273)	(509,400)	(10,113,913)			(29,337,265)
6/30/2022	(9,128,497)	(9,585,455)	(18,713,953)	(30,127)		(479,273)	(509,400)	(10,623,312)			(29,337,265)
7/31/2022	(9,098,370)	(9,106,182)	(18,204,553)	(30,127)		(479,273)	(509,400)	(11,132,712)			(29,337,265)
8/31/2022	(9,068,243)	(8,626,910)	(17,695,153)	(30,127)		(479,273)	(509,400)	(11,642,112)			(29,337,265)
9/30/2022	(9,038,116)	(8,147,637)	(17,185,753)	(30,127)		(479,273)	(509,400)	(12,151,512)			(29,337,265)
10/31/2022	(9,007,989)	(7,668,364)	(16,676,353)	(30,127)		(479,273)	(509,400)	(12,660,912)			(29,337,265)
11/30/2022	(8,977,862)	(7,189,091)	(16,166,953)	(30,127)		(479,273)	(509,400)	(13,170,312)			(29,337,265)
12/31/2022	(8,947,735)	(6,709,819)	(15,657,554)	(30,127)		(479,273)	(509,400)	(13,679,711)			(29,337,265)
1/31/2023	(8,917,608)	(6,230,546)	(15,148,154)	(30,127)		(479,273)	(509,400)	(14,189,111)			(29,337,265)
2/28/2023	(8,887,481)	(5,751,273)	(14,638,754)	(30,127)		(479,273)	(509,400)	(14,698,511)			(29,337,265)
3/31/2023	(8,857,354)	(5,272,000)	(14,129,354)	(30,127)		(479,273)	(509,400)	(15,207,911)			(29,337,265)
4/30/2023	(8,827,227)	(4,792,728)	(13,619,954)	(30,127)		(479,273)	(509,400)	(15,717,311)			(29,337,265)
5/31/2023	(8,797,100)	(4,313,455)	(13,110,555)	(30,127)		(479,273)	(509,400)	(16,226,710)			(29,337,265)
6/30/2023	(8,766,973)	(3,834,182)	(12,601,155)	(30,127)		(479,273)	(509,400)	(16,736,110)			(29,337,265)
7/31/2023	(8,736,846)	(3,354,909)	(12,091,755)	(30,127)		(479,273)	(509,400)	(17,245,510)			(29,337,265)
8/31/2023	(8,706,719)	(2,875,637)	(11,582,355)	(30,127)		(479,273)	(509,400)	(17,754,910)			(29,337,265)
9/30/2023	(8,676,592)	(2,396,364)	(11,072,955)	(30,127)		(479,273)	(509,400)	(18,264,310)			(29,337,265)
10/31/2023	(8,646,465)	(1,917,091)	(10,563,556)	(30,127)		(479,273)	(509,400)	(18,773,709)			(29,337,265)
11/30/2023	(8,616,338)	(1,437,818)	(10,054,156)	(30,127)		(479,273)	(509,400)	(19,283,109)			(29,337,265)
12/31/2023	(8,586,210)	(958,546)	(9,544,756)	(30,127)		(479,273)	(509,400)	(19,792,509)			(29,337,265)
1/31/2024	(8,556,083)	(479,273)	(9,035,356)	(30,127)		(479,273)	(509,400)	(20,301,909)			(29,337,265)
2/29/2024	(8,525,956)	(0)	(8,525,956)	(30,127)		(479,273)	(509,400)	(20,811,309)			(29,337,265)
3/31/2024	(8,495,829)	(0)	(8,495,829)	(30,127)			(30,127)	(20,841,436)			(29,337,265)
4/30/2024	(8,465,702)	(0)	(8,465,702)	(30,127)			(30,127)	(20,871,563)			(29,337,265)
5/31/2024	(8,435,575)	(0)	(8,435,575)	(30,127)			(30,127)	(20,901,690)			(29,337,265)
6/30/2024	(8,405,448)	(0)	(8,405,448)	(30,127)			(30,127)	(20,931,817)			(29,337,265)
7/31/2024	(8,375,321)	(0)	(8,375,321)	(30,127)			(30,127)	(20,961,944)			(29,337,265)
8/31/2024	(8,345,194)	(0)	(8,345,194)	(30,127)			(30,127)	(20,992,071)			(29,337,265)
9/30/2024	(8,315,067)	(0)	(8,315,067)	(30,127)			(30,127)	(21,022,198)			(29,337,265)
10/31/2024	(8,284,940)	(0)	(8,284,940)	(30,127)			(30,127)	(21,052,325)			(29,337,265)
11/30/2024	(8,254,813)	(0)	(8,254,813)	(30,127)			(30,127)	(21,082,452)			(29,337,265)
12/31/202											

12/31/2028	(6,778,588)	(0)	(6,778,588)	(30,127)	(30,127)	(22,558,677)	(29,337,265)
1/31/2029	(6,748,461)	(0)	(6,748,461)	(30,127)	(30,127)	(22,588,804)	(29,337,265)
2/28/2029	(6,718,333)	(0)	(6,718,333)	(30,127)	(30,127)	(22,618,932)	(29,337,265)
3/31/2029	(6,688,206)	(0)	(6,688,206)	(30,127)	(30,127)	(22,649,059)	(29,337,265)
4/30/2029	(6,658,079)	(0)	(6,658,079)	(30,127)	(30,127)	(22,679,186)	(29,337,265)
5/31/2029	(6,627,952)	(0)	(6,627,952)	(30,127)	(30,127)	(22,709,313)	(29,337,265)
6/30/2029	(6,597,825)	(0)	(6,597,825)	(30,127)	(30,127)	(22,739,440)	(29,337,265)
7/31/2029	(6,567,698)	(0)	(6,567,698)	(30,127)	(30,127)	(22,769,567)	(29,337,265)
8/31/2029	(6,537,571)	(0)	(6,537,571)	(30,127)	(30,127)	(22,799,694)	(29,337,265)
9/30/2029	(6,507,444)	(0)	(6,507,444)	(30,127)	(30,127)	(22,829,821)	(29,337,265)
10/31/2029	(6,477,317)	(0)	(6,477,317)	(30,127)	(30,127)	(22,859,948)	(29,337,265)
11/30/2029	(6,447,190)	(0)	(6,447,190)	(30,127)	(30,127)	(22,890,075)	(29,337,265)
12/31/2029	(6,417,063)	(0)	(6,417,063)	(30,127)	(30,127)	(22,920,202)	(29,337,265)
1/31/2030	(6,386,936)	(0)	(6,386,936)	(30,127)	(30,127)	(22,950,329)	(29,337,265)
2/28/2030	(6,356,809)	(0)	(6,356,809)	(30,127)	(30,127)	(22,980,456)	(29,337,265)
3/31/2030	(6,326,682)	(0)	(6,326,682)	(30,127)	(30,127)	(23,010,583)	(29,337,265)
4/30/2030	(6,296,555)	(0)	(6,296,555)	(30,127)	(30,127)	(23,040,710)	(29,337,265)
5/31/2030	(6,266,428)	(0)	(6,266,428)	(30,127)	(30,127)	(23,070,837)	(29,337,265)
6/30/2030	(6,236,301)	(0)	(6,236,301)	(30,127)	(30,127)	(23,100,964)	(29,337,265)
7/31/2030	(6,206,174)	(0)	(6,206,174)	(30,127)	(30,127)	(23,131,091)	(29,337,265)
8/31/2030	(6,176,047)	(0)	(6,176,047)	(30,127)	(30,127)	(23,161,218)	(29,337,265)
9/30/2030	(6,145,920)	(0)	(6,145,920)	(30,127)	(30,127)	(23,191,345)	(29,337,265)
10/31/2030	(6,115,792)	(0)	(6,115,792)	(30,127)	(30,127)	(23,221,473)	(29,337,265)
11/30/2030	(6,085,665)	(0)	(6,085,665)	(30,127)	(30,127)	(23,251,600)	(29,337,265)
12/31/2030	(6,055,538)	(0)	(6,055,538)	(30,127)	(30,127)	(23,281,727)	(29,337,265)
1/31/2031	(6,025,411)	(0)	(6,025,411)	(30,127)	(30,127)	(23,311,854)	(29,337,265)
2/28/2031	(5,995,284)	(0)	(5,995,284)	(30,127)	(30,127)	(23,341,981)	(29,337,265)
3/31/2031	(5,965,157)	(0)	(5,965,157)	(30,127)	(30,127)	(23,372,108)	(29,337,265)
4/30/2031	(5,935,030)	(0)	(5,935,030)	(30,127)	(30,127)	(23,402,235)	(29,337,265)
5/31/2031	(5,904,903)	(0)	(5,904,903)	(30,127)	(30,127)	(23,432,362)	(29,337,265)
6/30/2031	(5,874,776)	(0)	(5,874,776)	(30,127)	(30,127)	(23,462,489)	(29,337,265)
7/31/2031	(5,844,649)	(0)	(5,844,649)	(30,127)	(30,127)	(23,492,616)	(29,337,265)
8/31/2031	(5,814,522)	(0)	(5,814,522)	(30,127)	(30,127)	(23,522,743)	(29,337,265)
9/30/2031	(5,784,395)	(0)	(5,784,395)	(30,127)	(30,127)	(23,552,870)	(29,337,265)
10/31/2031	(5,754,268)	(0)	(5,754,268)	(30,127)	(30,127)	(23,582,997)	(29,337,265)
11/30/2031	(5,724,141)	(0)	(5,724,141)	(30,127)	(30,127)	(23,613,124)	(29,337,265)
12/31/2031	(5,694,014)	(0)	(5,694,014)	(30,127)	(30,127)	(23,643,251)	(29,337,265)
1/31/2032	(5,663,887)	(0)	(5,663,887)	(30,127)	(30,127)	(23,673,378)	(29,337,265)
2/29/2032	(5,633,760)	(0)	(5,633,760)	(30,127)	(30,127)	(23,703,505)	(29,337,265)
3/31/2032	(5,603,633)	(0)	(5,603,633)	(30,127)	(30,127)	(23,733,632)	(29,337,265)
4/30/2032	(5,573,506)	(0)	(5,573,506)	(30,127)	(30,127)	(23,763,759)	(29,337,265)
5/31/2032	(5,543,379)	(0)	(5,543,379)	(30,127)	(30,127)	(23,793,886)	(29,337,265)
6/30/2032	(5,513,252)	(0)	(5,513,252)	(30,127)	(30,127)	(23,824,013)	(29,337,265)
7/31/2032	(5,483,124)	(0)	(5,483,124)	(30,127)	(30,127)	(23,854,141)	(29,337,265)
8/31/2032	(5,452,997)	(0)	(5,452,997)	(30,127)	(30,127)	(23,884,268)	(29,337,265)
9/30/2032	(5,422,870)	(0)	(5,422,870)	(30,127)	(30,127)	(23,914,395)	(29,337,265)
10/31/2032	(5,392,743)	(0)	(5,392,743)	(30,127)	(30,127)	(23,944,522)	(29,337,265)
11/30/2032	(5,362,616)	(0)	(5,362,616)	(30,127)	(30,127)	(23,974,649)	(29,337,265)
12/31/2032	(5,332,489)	(0)	(5,332,489)	(30,127)	(30,127)	(24,004,776)	(29,337,265)
1/31/2033	(5,302,362)	(0)	(5,302,362)	(30,127)	(30,127)	(24,034,903)	(29,337,265)
2/28/2033	(5,272,235)	(0)	(5,272,235)	(30,127)	(30,127)	(24,065,030)	(29,337,265)
3/31/2033	(5,242,108)	(0)	(5,242,108)	(30,127)	(30,127)	(24,095,157)	(29,337,265)
4/30/2033	(5,211,981)	(0)	(5,211,981)	(30,127)	(30,127)	(24,125,284)	(29,337,265)
5/31/2033	(5,181,854)	(0)	(5,181,854)	(30,127)	(30,127)	(24,155,411)	(29,337,265)
6/30/2033	(5,151,727)	(0)	(5,151,727)	(30,127)	(30,127)	(24,185,538)	(29,337,265)
7/31/2033	(5,121,600)	(0)	(5,121,600)	(30,127)	(30,127)	(24,215,665)	(29,337,265)
8/31/2033	(5,091,473)	(0)	(5,091,473)	(30,127)	(30,127)	(24,245,792)	(29,337,265)
9/30/2033	(5,061,346)	(0)	(5,061,346)	(30,127)	(30,127)	(24,275,919)	(29,337,265)
10/31/2033	(5,031,219)	(0)	(5,031,219)	(30,127)	(30,127)	(24,306,046)	(29,337,265)
11/30/2033	(5,001,092)	(0)	(5,001,092)	(30,127)	(30,127)	(24,336,173)	(29,337,265)
12/31/2033	(4,970,965)	(0)	(4,970,965)	(30,127)	(30,127)	(24,366,300)	(29,337,265)
1/31/2034	(4,940,838)	(0)	(4,940,838)	(30,127)	(30,127)	(24,396,427)	(29,337,265)
2/28/2034	(4,910,711)	(0)	(4,910,711)	(30,127)	(30,127)	(24,426,554)	(29,337,265)
3/31/2034	(4,880,583)	(0)	(4,880,583)	(30,127)	(30,127)	(24,456,682)	(29,337,265)
4/30/2034	(4,850,456)	(0)	(4,850,456)	(30,127)	(30,127)	(24,486,809)	(29,337,265)
5/31/2034	(4,820,329)	(0)	(4,820,329)	(30,127)	(30,127)	(24,516,936)	(29,337,265)
6/30/2034	(4,790,202)	(0)	(4,790,202)	(30,127)	(30,127)	(24,547,063)	(29,337,265)
7/31/2034	(4,760,075)	(0)	(4,760,075)	(30,127)	(30,127)	(24,577,190)	(29,337,265)
8/31/2034	(4,729,948)	(0)	(4,729,948)	(30,127)	(30,127)	(24,607,317)	(29,337,265)
9/30/2034	(4,699,821)	(0)	(4,699,821)	(30,127)	(30,127)	(24,637,444)	(29,337,265)
10/31/2034	(4,669,694)	(0)	(4,669,694)	(30,127)	(30,127)	(24,667,571)	(29,337,265)
11/30/2034	(4,639,567)	(0)	(4,639,567)	(30,127)	(30,127)	(24,697,698)	(29,337,265)
12/31/2034	(4,609,440)	(0)	(4,609,440)	(30,127)	(30,127)	(24,727,825)	(29,337,265)
1/31/2035	(4,579,313)	(0)	(4,579,313)	(30,127)	(30,127)	(24,757,952)	(29,337,265)
2/28/2035	(4,549,186)	(0)	(4,549,186)	(30,127)	(30,127)	(24,788,079)	(29,337,265)
3/31/2035	(4,519,059)	(0)	(4,519,059)	(30,127)	(30,127)	(24,818,206)	(29,337,265)
4/30/2035	(4,488,932)	(0)	(4,488,932)	(30,127)	(30,127)	(24,848,333)	(29,337,265)
5/31/2035	(4,458,805)	(0)	(4,458,805)	(30,127)	(30,127)	(24,878,460)	(29,337,265)
6/30/2035	(4,428,678)	(0)	(4,428,678)	(30,127)	(30,127)	(24,908,587)	(29,337,265)
7/31/2035	(4,398,551)	(0)	(4,398,551)	(30,127)	(30,127)	(24,938,714)	(29,337,265)
8/31/2035	(4,368,424)	(0)	(4,368,424)	(30,127)	(30,127)	(24,968,841)	(29,337,265)
9/30/2035	(4,338,297)	(0)	(4,338,297)	(30,127)	(30,127)	(24,998,968)	(29,337,265)
10/31/2035	(4,308,170)	(0)	(4,308,170)	(30,127)	(30,127)	(25,029,095)	(29,337,265)
11/30/2035	(4,278,043)	(0)	(4,278,043)	(30,127)	(30,127)	(25,059,222)	(29,337,265)
12/31/2035	(4,247,915)	(0)	(4,247,915)	(30,127)	(30,127)	(25,089,350)	(29,337,265)
1/31/2036	(4,217,788)	(0)	(4,217,788)	(30,127)	(30,127)	(25,119,477)	(29,337,265)
2/29/2036	(4,187,661)	(0)	(4,187,661)	(30,127)	(30,127)	(25,149,604)	(29,337,265)
3/31/2036	(4,157,534)	(0)	(4,157,534)	(30,127)	(30,127)	(25,179,731)	(29,337,265)
4/30/2036	(4,127,407)	(0)	(4,127,407)	(30,127)	(30,127)	(25,209,858)	(29,337,265)
5/31/2036	(4,097,280)	(0)	(4,097,280)	(30,127)	(30,127)	(25,239,985)	(29,337,265)
6/30/2036	(4,067,153)	(0)	(4,067,153)	(30,127)	(30,127)	(25,270,112)	(29,337,265)
7/31/2036	(4,037,026)	(0)	(4,037,026)	(30,127)	(30,127)	(25,300,239)	(29,337,265)
8/31/2036	(4,006,899)	(0)	(4,006,899)	(30,127)	(30,127)	(25,330,366)	(29,337,265)
9/30/2036	(3,976,772)	(0)	(3,976,772)	(30,127)	(30,127)	(25,360,493)	(29,337,265)
10/31/2036	(3,946,645)	(0)	(3,946,645)	(30,127)	(30,127)	(25,390,620)	(29,337,265)
11/30/2036	(3,916,518)	(0)	(3,916,518)	(30,127)	(30,127)	(25,420,747)	(29,337,265)
12/31/2036	(3,886,391)	(0)	(3,886,391)	(30,127)	(30,127)	(25,450,874)	(29,337,265)
1/31/2037	(3,856,264)	(0)	(3,856,264)	(30,127)	(30,127)	(25,481,001)	(29,337,265)
2/28/2037	(3,826,137)	(0)	(3,826,137)	(30,127)	(30,127)	(25,511,128)	(29,337,265)
3/31/2037	(3,796,010)	(0)	(3,796,010)	(30,127)	(30,127)	(25,541,255)	(29,337,265)
4/30/2037	(3,765,883)	(0)	(3,765,883)	(30,127)	(30,127)	(25,571,382)	(29,337,265)
5/31/2037	(3,735,756)	(0)	(3,735,756)	(30,127)	(30,127)	(25,601,509)	(29,337,265)
6/30/2037	(3,705,629)	(0)	(3,705,629)	(30,127)	(30,127)	(25,631,636)	(29,337,265)
7/31/2037	(3,675,502)	(0)	(3,675,502)	(30,127)	(30,127)	(25,661,763)	(29,337,265)
8/31/2037	(3,645,374)	(0)	(3,645,374)	(30,127)	(30,127)	(25,691,891)	(29,337,265)
9/30/2037	(3,615,247)	(0)	(3,615,247)	(30,127)	(30,127)	(25,722,018)	(29,337,265)
10/31/2037	(3,585,120)	(0)	(3,585,120)	(30,127)	(30,127)	(25,752,145)	(29,337,265)
11/30/2037	(3,554,993)	(0)	(3,554,993)	(30,127)	(30,127)	(25,782,272)	(29,337,265)
12/31/2037	(3,524,866)	(0)	(3,524,866)	(30,127)	(30,127)	(25,812,399)	(29,337,265)
1/31/2038	(3,494,739)	(0)	(3,494,739)	(30,127)	(30,127)	(25,842,526)	(29,337,265)
2/28/2038	(3,464,612)	(0)	(3,464,612)	(30,127)	(30,127)	(25,872,653)	(29,337,265)
3/31/2038	(3,434,485)	(0)	(3,434,485)	(30,127)	(30,127)	(25,902,780)	(29,337,265)
4/30/2038	(3,404,358)	(0)	(3,404,358)	(30,127)	(30,127)	(25,932,907)	(29,337,265)
5/31/2038	(3,374,231)	(0)	(3,374,231)	(30,127)	(30,127)	(25,963,034)	(29,337,265)
6/30/2038	(3,344,104)	(0)	(3,344,104)	(30,127)	(30,127)	(25,993,161)	(29,337,265)
7/31/2038	(3,313,977)	(0)	(3,313,977)	(30,127)	(30,127)	(26,023,288)	(29,337,265)
8/31/2038	(3,283,850)	(0)	(3,283,850)	(30,127)	(30,127)	(26,053,415)	(29,337,265)
9/30/2038	(3,253,723)	(0)	(3,25				

8/31/2040	(2,560,801)	(0)	(2,560,801)	(30,127)	(30,127)	(26,776,464)	(29,337,265)
9/30/2040	(2,530,674)	(0)	(2,530,674)	(30,127)	(30,127)	(26,806,591)	(29,337,265)
10/31/2040	(2,500,547)	(0)	(2,500,547)	(30,127)	(30,127)	(26,836,718)	(29,337,265)
11/30/2040	(2,470,420)	(0)	(2,470,420)	(30,127)	(30,127)	(26,866,845)	(29,337,265)
12/31/2040	(2,440,293)	(0)	(2,440,293)	(30,127)	(30,127)	(26,896,972)	(29,337,265)
1/31/2041	(2,410,165)	(0)	(2,410,165)	(30,127)	(30,127)	(26,927,100)	(29,337,265)
2/28/2041	(2,380,038)	(0)	(2,380,038)	(30,127)	(30,127)	(26,957,227)	(29,337,265)
3/31/2041	(2,349,911)	(0)	(2,349,911)	(30,127)	(30,127)	(26,987,354)	(29,337,265)
4/30/2041	(2,319,784)	(0)	(2,319,784)	(30,127)	(30,127)	(27,017,481)	(29,337,265)
5/31/2041	(2,289,657)	(0)	(2,289,657)	(30,127)	(30,127)	(27,047,608)	(29,337,265)
6/30/2041	(2,259,530)	(0)	(2,259,530)	(30,127)	(30,127)	(27,077,735)	(29,337,265)
7/31/2041	(2,229,403)	(0)	(2,229,403)	(30,127)	(30,127)	(27,107,862)	(29,337,265)
8/31/2041	(2,199,276)	(0)	(2,199,276)	(30,127)	(30,127)	(27,137,989)	(29,337,265)
9/30/2041	(2,169,149)	(0)	(2,169,149)	(30,127)	(30,127)	(27,168,116)	(29,337,265)
10/31/2041	(2,139,022)	(0)	(2,139,022)	(30,127)	(30,127)	(27,198,243)	(29,337,265)
11/30/2041	(2,108,895)	(0)	(2,108,895)	(30,127)	(30,127)	(27,228,370)	(29,337,265)
12/31/2041	(2,078,768)	(0)	(2,078,768)	(30,127)	(30,127)	(27,258,497)	(29,337,265)
1/31/2042	(2,048,641)	(0)	(2,048,641)	(30,127)	(30,127)	(27,288,624)	(29,337,265)
2/28/2042	(2,018,514)	(0)	(2,018,514)	(30,127)	(30,127)	(27,318,751)	(29,337,265)
3/31/2042	(1,988,387)	(0)	(1,988,387)	(30,127)	(30,127)	(27,348,878)	(29,337,265)
4/30/2042	(1,958,260)	(0)	(1,958,260)	(30,127)	(30,127)	(27,379,005)	(29,337,265)
5/31/2042	(1,928,133)	(0)	(1,928,133)	(30,127)	(30,127)	(27,409,132)	(29,337,265)
6/30/2042	(1,898,006)	(0)	(1,898,006)	(30,127)	(30,127)	(27,439,259)	(29,337,265)
7/31/2042	(1,867,879)	(0)	(1,867,879)	(30,127)	(30,127)	(27,469,386)	(29,337,265)
8/31/2042	(1,837,752)	(0)	(1,837,752)	(30,127)	(30,127)	(27,499,513)	(29,337,265)
9/30/2042	(1,807,624)	(0)	(1,807,624)	(30,127)	(30,127)	(27,529,641)	(29,337,265)
10/31/2042	(1,777,497)	(0)	(1,777,497)	(30,127)	(30,127)	(27,559,768)	(29,337,265)
11/30/2042	(1,747,370)	(0)	(1,747,370)	(30,127)	(30,127)	(27,589,895)	(29,337,265)
12/31/2042	(1,717,243)	(0)	(1,717,243)	(30,127)	(30,127)	(27,620,022)	(29,337,265)
1/31/2043	(1,687,116)	(0)	(1,687,116)	(30,127)	(30,127)	(27,650,149)	(29,337,265)
2/28/2043	(1,656,989)	(0)	(1,656,989)	(30,127)	(30,127)	(27,680,276)	(29,337,265)
3/31/2043	(1,626,862)	(0)	(1,626,862)	(30,127)	(30,127)	(27,710,403)	(29,337,265)
4/30/2043	(1,596,735)	(0)	(1,596,735)	(30,127)	(30,127)	(27,740,530)	(29,337,265)
5/31/2043	(1,566,608)	(0)	(1,566,608)	(30,127)	(30,127)	(27,770,657)	(29,337,265)
6/30/2043	(1,536,481)	(0)	(1,536,481)	(30,127)	(30,127)	(27,800,784)	(29,337,265)
7/31/2043	(1,506,354)	(0)	(1,506,354)	(30,127)	(30,127)	(27,830,911)	(29,337,265)
8/31/2043	(1,476,227)	(0)	(1,476,227)	(30,127)	(30,127)	(27,861,038)	(29,337,265)
9/30/2043	(1,446,100)	(0)	(1,446,100)	(30,127)	(30,127)	(27,891,165)	(29,337,265)
10/31/2043	(1,415,973)	(0)	(1,415,973)	(30,127)	(30,127)	(27,921,292)	(29,337,265)
11/30/2043	(1,385,846)	(0)	(1,385,846)	(30,127)	(30,127)	(27,951,419)	(29,337,265)
12/31/2043	(1,355,719)	(0)	(1,355,719)	(30,127)	(30,127)	(27,981,546)	(29,337,265)
1/31/2044	(1,325,592)	(0)	(1,325,592)	(30,127)	(30,127)	(28,011,673)	(29,337,265)
2/29/2044	(1,295,465)	(0)	(1,295,465)	(30,127)	(30,127)	(28,041,800)	(29,337,265)
3/31/2044	(1,265,338)	(0)	(1,265,338)	(30,127)	(30,127)	(28,071,927)	(29,337,265)
4/30/2044	(1,235,211)	(0)	(1,235,211)	(30,127)	(30,127)	(28,102,054)	(29,337,265)
5/31/2044	(1,205,084)	(0)	(1,205,084)	(30,127)	(30,127)	(28,132,181)	(29,337,265)
6/30/2044	(1,174,956)	(0)	(1,174,956)	(30,127)	(30,127)	(28,162,309)	(29,337,265)
7/31/2044	(1,144,829)	(0)	(1,144,829)	(30,127)	(30,127)	(28,192,436)	(29,337,265)
8/31/2044	(1,114,702)	(0)	(1,114,702)	(30,127)	(30,127)	(28,222,563)	(29,337,265)
9/30/2044	(1,084,575)	(0)	(1,084,575)	(30,127)	(30,127)	(28,252,690)	(29,337,265)
10/31/2044	(1,054,448)	(0)	(1,054,448)	(30,127)	(30,127)	(28,282,817)	(29,337,265)
11/30/2044	(1,024,321)	(0)	(1,024,321)	(30,127)	(30,127)	(28,312,944)	(29,337,265)
12/31/2044	(994,194)	(0)	(994,194)	(30,127)	(30,127)	(28,343,071)	(29,337,265)
1/31/2045	(964,067)	(0)	(964,067)	(30,127)	(30,127)	(28,373,198)	(29,337,265)
2/28/2045	(933,940)	(0)	(933,940)	(30,127)	(30,127)	(28,403,325)	(29,337,265)
3/31/2045	(903,813)	(0)	(903,813)	(30,127)	(30,127)	(28,433,452)	(29,337,265)
4/30/2045	(873,686)	(0)	(873,686)	(30,127)	(30,127)	(28,463,579)	(29,337,265)
5/31/2045	(843,559)	(0)	(843,559)	(30,127)	(30,127)	(28,493,706)	(29,337,265)
6/30/2045	(813,432)	(0)	(813,432)	(30,127)	(30,127)	(28,523,833)	(29,337,265)
7/31/2045	(783,305)	(0)	(783,305)	(30,127)	(30,127)	(28,553,960)	(29,337,265)
8/31/2045	(753,178)	(0)	(753,178)	(30,127)	(30,127)	(28,584,087)	(29,337,265)
9/30/2045	(723,051)	(0)	(723,051)	(30,127)	(30,127)	(28,614,214)	(29,337,265)
10/31/2045	(692,924)	(0)	(692,924)	(30,127)	(30,127)	(28,644,341)	(29,337,265)
11/30/2045	(662,797)	(0)	(662,797)	(30,127)	(30,127)	(28,674,468)	(29,337,265)
12/31/2045	(632,670)	(0)	(632,670)	(30,127)	(30,127)	(28,704,595)	(29,337,265)
1/31/2046	(602,543)	(0)	(602,543)	(30,127)	(30,127)	(28,734,722)	(29,337,265)
2/28/2046	(572,415)	(0)	(572,415)	(30,127)	(30,127)	(28,764,850)	(29,337,265)
3/31/2046	(542,288)	(0)	(542,288)	(30,127)	(30,127)	(28,794,977)	(29,337,265)
4/30/2046	(512,161)	(0)	(512,161)	(30,127)	(30,127)	(28,825,104)	(29,337,265)
5/31/2046	(482,034)	(0)	(482,034)	(30,127)	(30,127)	(28,855,231)	(29,337,265)
6/30/2046	(451,907)	(0)	(451,907)	(30,127)	(30,127)	(28,885,358)	(29,337,265)
7/31/2046	(421,780)	(0)	(421,780)	(30,127)	(30,127)	(28,915,485)	(29,337,265)
8/31/2046	(391,653)	(0)	(391,653)	(30,127)	(30,127)	(28,945,612)	(29,337,265)
9/30/2046	(361,526)	(0)	(361,526)	(30,127)	(30,127)	(28,975,739)	(29,337,265)
10/31/2046	(331,399)	(0)	(331,399)	(30,127)	(30,127)	(29,005,866)	(29,337,265)
11/30/2046	(301,272)	(0)	(301,272)	(30,127)	(30,127)	(29,035,993)	(29,337,265)
12/31/2046	(271,145)	(0)	(271,145)	(30,127)	(30,127)	(29,066,120)	(29,337,265)
1/31/2047	(241,018)	(0)	(241,018)	(30,127)	(30,127)	(29,096,247)	(29,337,265)
2/28/2047	(210,891)	(0)	(210,891)	(30,127)	(30,127)	(29,126,374)	(29,337,265)
3/31/2047	(180,764)	(0)	(180,764)	(30,127)	(30,127)	(29,156,501)	(29,337,265)
4/30/2047	(150,637)	(0)	(150,637)	(30,127)	(30,127)	(29,186,628)	(29,337,265)
5/31/2047	(120,510)	(0)	(120,510)	(30,127)	(30,127)	(29,216,755)	(29,337,265)
6/30/2047	(90,383)	(0)	(90,383)	(30,127)	(30,127)	(29,246,882)	(29,337,265)
7/31/2047	(60,256)	(0)	(60,256)	(30,127)	(30,127)	(29,277,009)	(29,337,265)
8/31/2047	(30,129)	(0)	(30,129)	(30,127)	(30,127)	(29,307,136)	(29,337,265)
9/30/2047	(2)	(0)	(2)	(30,127)	(30,127)	(29,337,263)	(29,337,265)
Total Amortized from 10/15/2018 - 09/30/2047				(10,484,211)	(1,599,233)	(17,253,819)	(29,337,263)

TN Deferred Interest, Depreciation, & Ad Valorem Tax Expense Sep-21

Company 50 Service Area 093000

WP 7-10

Source - General Ledger

Description	Company	Cost Center	Account	Sub Account	Service Area	Sep-21
Depr Exp to Reg Asset	50	0000	4030	30005	93000	784,844.35
Ad Valorem Exp to Reg Asset	50	0000	4081	30101	93000	104,815.51
Interest to Reg Asset	50	0000	4310	30130	93000	1,435,124.80
RWIP Interest to Reg Asset	50	0000	4310	30130	93000	43,393.66
Grand Total						2,368,178.32

Description	Company	Cost Center	Account	Sub Account	Service Area	Sep-21
Depr Exp to Reg Asset	50	0000	1860	14218	93000	690,682.33
Ad Valorem Exp to Reg Asset	50	0000	1860	14218	93000	104,815.51
Interest to Reg Asset	50	0000	1860	14218	93000	1,353,270.40
RWIP Interest to Reg Asset	50	0000	1860	14218	93000	41,865.05
Grand Total						2,150,533.29

Revised WM

Division	Division Description	Account	unt Descrj	Sub Account	Sub Account Description	Desc	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Average
093	Tennessee Division	1860	Miscellaneous	14218	Rule 8209	Total Deferral	217,645	302,167	391,354	514,593	667,461	821,375	988,818	1,181,228	1,384,421	1,322,678	1,525,933	1,773,420	2,150,533	1,018,587
093	Tennessee Division	1860	Miscellaneous	14218	Rule 8209	Interest & RWIP Interest	(83,383)	(143,682)	(206,636)	(297,544)	(401,713)	(506,639)	(620,027)	(751,858)	(889,679)	(908,969)	(1,040,157)	(1,193,222)	(1,395,135)	(649,127)

Tennessee Distribution System
Computation of State Excise & Income Taxes
Twelve Months Ended September 30, 2021

Line No.	Description	Tax Rate	Test Year
	(a)	(b)	(c)
1	Required Return		\$ 33,588,589
2			
3	Current Return		\$ 30,677,152
4			
5	Pre-Tax Deficiency from Current Return		2,911,437
6	Tax Expansion Factor		1.3659
7	After-Tax Deficiency from Current Return		<u>3,976,732</u>
8			
9	Tax Liability Increase / Decrease (Ln 7 - Ln 3)		1,065,295
10	Current Tax Liability		<u>\$ 8,111,409</u>
11			
12	Income Tax Liability		\$ 9,176,704
13			
14	Less: ITC Amortization		<u>-</u>
15			
16	Total Income Tax Liability		<u><u>9,176,704</u></u>
17			
18	Note:		
19	1. Twelve months ended September 30, 2021		

Tennessee Distribution System
Computation of State Excise & Income Taxes
Twelve Months Ended September 30, 2021

Line No.	Description	Tax Rate	Test Year
	(a)	(b)	(c)
1	Required Return		\$ 32,058,035
2			
3	Current Return		\$ 29,165,421
4			
5	Pre-Tax Deficiency from Current Return		2,892,614
6	Tax Expansion Factor		1.3659
7	After-Tax Deficiency from Current Return		<u>3,951,021</u>
8			
9	Tax Liability Increase / Decrease (Ln 7 - Ln 3)		1,058,407
10	Current Tax Liability		<u>\$ 7,607,582</u>
11			
12	Income Tax Liability		\$ 8,665,989
13			
14	Less: ITC Amortization		<u>-</u>
15			
16	Total Income Tax Liability		<u><u>8,665,989</u></u>
17			
18	Note:		
19	1. Twelve months ended September 30, 2021		

Tennessee Distribution System
Amortization of UCG Deferred Utility ITC
Twelve Months Ended September 30, 2021

Line No.	Description	Amortization	Allocation Factor [1]	Tennessee Allocation
	(a)	(b)	(c)	(d)
1	Fiscal year ended September 30, 2011	50,990		
2	Fiscal year ended September 30, 2012	12,229		
3	Fiscal year ended September 30, 2013	5,820		
4	Fiscal year ended September 30, 2014	-		
5				
6	Base Period ended September 30, 2017	-		-
7				
8	Attrition Year ended May 31, 2020	-		-
9				
10	[1] Division 091 - Mid-States General Office allocation factor excluding Kentucky			

**Tennessee Distribution System
Revenue Conversion Factor
Twelve Months Ended September 30, 2021**

Line No.		Test Year	
		Amount	Balance
1	Operating Revenues		1.000000
2			
3	Add: Forfeited Discounts	(0.000001)	<u>-0.000001</u>
4			
5	Balance		0.999999
6			
7	Uncollectible Ratio	0.008825	<u>0.008825</u>
8			
9	Balance		0.991173
10			
11	State Excise Tax	0.065000	<u>0.064426</u>
12			
13	Balance		0.926747
14			
15	Federal Income Tax	0.210000	<u>0.194617</u>
16			
17	Balance		0.732130
18			
19	Revenue Conversion Factor (Line 1/Line 9)		1.365900

**Tennessee Distribution System
Overall Cost of Capital
Twelve Months Ended September 30, 2021**

Line No.	Description	Percent	Cost Rate	Overall Cost of Capital
	(a)	(b)	(c)	(d)
1	Long Term Debt Capital	39.36%	3.94%	1.55%
2	Short Term Debt	0.05%	69.89%	0.04%
3	Equity Capital	<u>60.59%</u>	9.80%	<u>5.94%</u>
4				
5	Total Capital	<u><u>100.0%</u></u>		<u><u>7.53%</u></u>

**Tennessee Distribution System
Overall Cost of Capital
Twelve Months Ended September 30, 2021**

Line No.	Description	Percent	Cost Rate	Overall Cost of Capital
	(a)	(b)	(c)	(d)
1	Long Term Debt Capital	40.45%	3.94%	1.59%
2	Short Term Debt	0.05%	69.89%	0.04%
3	Equity Capital	<u>59.50%</u>	9.80%	<u>5.83%</u>
4				
5	Total Capital	<u><u>100.0%</u></u>		<u><u>7.46%</u></u>

Tennessee Distribution System
Cost of Capital
Twelve Months Ended September 30, 2021

Line No.	Description	<u>September 30, 2021</u>	
		\$	%
	(a)	(b)	(c)
1	LT Debt	\$ 5,137,313,848	39.36%
2	ST Debt	6,537,896	0.05%
3	Equity	7,906,888,837	60.59%
4			
5	Total Capital	<u>\$ 13,050,740,580</u>	<u>100.00%</u>

Tennessee Distribution System
Cost of Capital
Twelve Months Ended September 30, 2021

Line No.	Description	<u>September 30, 2021</u>	
		\$	%
	(a)	(b)	(c)
1	LT Debt	\$ 5,083,310,847	40.45%
2	ST Debt	6,537,896	0.05%
3	Equity	7,477,338,946	59.50%
4			
5	Total Capital	<u>\$ 12,567,187,689</u>	<u>100.00%</u>

Tennessee Distribution System
Cost of Capital- Short Term Debt Rate
Twelve Months Ended September 30, 2021

Atmos Consolidated Balances					12 Month Avg	12 Month Avg	
					Atmos Consolidated - calc of STD rate		
Line		Long-Term	Short-Term		STD	STD	STD
No.	Date	Debt	Debt	Equity	Avg Daily Bal	Int Exp & fees	avg rate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Sep-20	4,531,944,234	-	6,791,203,456			
2	Oct-20	5,124,535,942	-	6,875,466,222	-	405,501	
3	Nov-20	5,124,818,909	-	6,868,006,033	-	399,760	
4	Dec-20	5,125,033,150	-	7,213,155,664	-	405,501	
5	Jan-21	5,125,258,556	-	7,373,460,669	-	405,516	
6	Feb-21	5,125,483,885	59,994,400	7,438,802,054	15,000,000	398,490	
7	Mar-21	5,125,753,448	-	7,820,925,344	40,645,161	554,528	
8	Apr-21	5,125,978,022	-	7,844,770,874	-	348,096	
9	May-21	5,126,202,515	-	7,787,132,838	-	355,951	
10	Jun-21	5,136,702,172	-	7,773,757,588	-	349,209	
11	Jul-21	5,136,905,214	-	7,780,443,380	-	355,951	
12	Aug-21	5,137,111,123	24,998,243	7,731,393,336	5,645,161	356,486	
13	Sep-21	5,137,313,848	-	7,906,888,837	19,166,667	350,966	
14						4,685,956	
15							
16	Average	5,083,310,847	6,537,896	7,477,338,946	6,704,749		69.89%

Interest on CP or Interest on Draws on Credit Facility	Commitment Fees on Credit Facility	Bank Fees on AEC Credit Facility With RBS
30121		
Detail of Colm (f) Consolidated Int Exp & Fees		
Int Exp	Commit fees	Utility Bank Admin
-	177,988	227,514
-	172,246	227,514
-	177,988	227,514
-	178,002	227,514
1,867	169,109	227,514
5,600	229,002	319,926
-	202,260	145,835
-	209,002	146,949
-	202,260	146,949
-	209,002	146,949
535	209,002	146,949
1,757	202,260	146,949
9,758	2,338,122	2,338,077
per STD rpts:	4,685,956	

Tennessee Distribution System
Cost of Capital- Long Term Debt Rate
Twelve Months Ended September 30, 2021

Line No.	Debt Series (a)	Issued (b)	Outstanding 9/30/2020 (c)	Outstanding 10/31/2020 (d)	Outstanding 11/30/2020 (e)	Outstanding 12/31/2020 (f)	Outstanding 1/31/2021 (g)	Outstanding 2/28/2021 (h)	Outstanding 3/31/2021 (i)	Outstanding 4/30/2021 (j)	Outstanding 5/31/2021 (k)
1	9.40% First Mortgage Bond J due May 2021/RET 2005	04/01/91	-	-	-	-	-	-	-	-	-
2	6.75% Debentures Unsecured due July 2028	07/27/98	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000
3	5.125% Senior Notes due Jan 2013	01/13/03	-	-	-	-	-	-	-	-	-
4	10.43% First Mortgage Bond P due 2017 (eff 2012)	11/01/87	-	-	-	-	-	-	-	-	-
5	9.75% First Mortgage Bond Q due Apr 2020/RET 2005	04/01/90	-	-	-	-	-	-	-	-	-
6	9.32% First Mortgage Bond T due June 2021/RET 2005	06/01/91	-	-	-	-	-	-	-	-	-
7	8.77% First Mortgage Bond U due May 2022/RET 2005	05/01/92	-	-	-	-	-	-	-	-	-
8	6.67% MTN A1 due Dec 2025	12/15/95	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
9	4.95% Sr Note due 10/15/2014	10/22/04	-	-	-	-	-	-	-	-	-
10	5.95% Sr Note due 10/15/2034	10/22/04	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000
11	4.3% Sr Note due 10/1/2048	10/2018	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000
12	Sr Note 5.50% Due 06/15/2041	6/10/11	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000
13	8.50% Sr Note due 3/15/2019	03/23/09	-	-	-	-	-	-	-	-	-
14	4.15% Sr Note due 1/15/2043	01/15/13	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000
15	4.125% Sr Note due 10/15/2044	10/15/14	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000
16	3% Sr Note due 6/15/2027	06/2017	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000
17	4.125% Sr Note due 3/15/49	03/2019	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000
18	2.625% Sr Notes Due 2029	10/2019	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000
19	3.375% Sr Notes Due 2049	10/2019	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000
20	\$200MM 3YR, Sr Credit Facility (Established 9/22/16)	04/2020	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000
23	1.500% Sr Notes Due 2031	10/01/20	-	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000
24	2.850% Sr Notes Due 2052 - Placeholder Oct-21 Issue	10/2021	-	-	-	-	-	-	-	-	-
25	October 2022 - Swap Position	07/2020	-	-	-	-	-	-	-	-	-
26	October 2024 - Swap Position	07/2020	-	-	-	-	-	-	-	-	-
27	October 2023 - Swap Position	07/2020	-	-	-	-	-	-	-	-	-
28	October 2025 - Swap Position	07/2020	-	-	-	-	-	-	-	-	-
29	Subtotal -- Utility Long-Term Debt		\$ 4,560,000,000	\$ 5,160,000,000	\$ 5,160,000,000	\$ 5,160,000,000	\$ 5,160,000,000	\$ 5,160,000,000	\$ 5,160,000,000	\$ 5,160,000,000	\$ 5,160,000,000
30											
31	Othwe Long-Term Debt		-	-	-	-	-	-	-	-	-
32	Total Long-Term Debt		4,560,000,000	5,160,000,000	5,160,000,000	5,160,000,000	5,160,000,000	5,160,000,000	5,160,000,000	5,160,000,000	5,160,000,000
33	Less Unamortized Debt Discount & Debt Premium		\$ 582,716	\$ 3,179,369	\$ 3,123,925	\$ 3,089,529	\$ 3,055,133	\$ 3,020,737	\$ 2,986,341	\$ 2,951,945	\$ 2,917,550
34	Less Unamortized Debt Expense		\$ 36,102,992	\$ 40,918,941	\$ 40,678,160	\$ 40,484,979	\$ 40,280,557	\$ 40,076,135	\$ 39,871,714	\$ 39,667,292	\$ 39,462,870
35	Annualized Amortization of T-Lock Settlement, Debt Exp. & Debt Disct.										
36			\$ 4,523,314,292	\$ 5,115,901,690	\$ 5,116,197,916	\$ 5,116,425,492	\$ 5,116,664,310	\$ 5,116,903,128	\$ 5,117,141,945	\$ 5,117,380,763	\$ 5,117,619,580
37	Effective Avg Cost of Consol Debt										
38	Consolidated & Utility										
39	Other Long-Term Real Estate Lease		\$ 8,629,942	\$ 8,634,252	\$ 8,620,993	\$ 8,607,658	\$ 8,594,246	\$ 8,580,757	\$ 8,611,503	\$ 8,597,259	\$ 8,582,935
40	Total Long-Term Debt Including Capital Leases		\$ 4,531,944,234	\$ 5,124,535,942	\$ 5,124,818,909	\$ 5,125,033,150	\$ 5,125,258,556	\$ 5,125,483,885	\$ 5,125,753,448	\$ 5,125,978,022	\$ 5,126,202,515

Note: includes current maturities

Note: includes current maturities

**Tennessee Distribution System
Rate of Return
Twelve Months Ended September 30, 2021**

Line No.	Description (a)	Reference (b)	Test Year (c)
1	Total Revenues	Sch. 1	\$ 141,610,603
2			
3	Gas Cost	Sch. 3	55,628,730
4			
5	Operation & Maintenance Expense	Sch. 1	22,347,772
6			
7	Taxes Other Than Income Taxes	Sch. 5	8,295,367
8			
9	Depreciation & Amortization Expense	Sch. 1	17,174,980
10			
11	Federal Income and State Excise Tax	WP 10-1	8,111,409
12			
13	Interest on Customer Deposits	Sch. 1	34,768
14			
15	AFUDC Interest credit	WP 1-2	<u>(659,575)</u>
16			
17	Return on Rate Base		<u>\$ 30,677,152</u>
18			
19	Total Rate Base	Sch. 7	\$ 446,063,594
20			
21	Rate of Return on Rate Base		6.88%
22			
23	Interest Expense	Sch. 9, Sch. 7	7,092,411
24			
25			
26	Return on Equity		<u>\$ 23,584,741</u>
27			
28	Rate of Return on Equity		8.73%
29			
30	Note:		
31	1. Twelve months ended September 30, 2021		

Tennessee Distribution System
Rate of Return
Twelve Months Ended September 30, 2021

Line No.	Description (a)	Reference (b)	Historic Base Period (1) (c)
1	Total Revenues	Sch. 1R	\$ 138,165,384
2			
3	Gas Cost	Sch. 3	55,628,730
4			
5	Operation & Maintenance Expense	Sch. 1R	22,347,772
6			
7	Taxes Other Than Income Taxes	Sch. 5	8,295,367
8			
9	Depreciation & Amortization Expense	Sch. 1R	15,745,319
10			
11	Federal Income and State Excise Tax	Wp 10-1R	7,607,582
12			
13	Interest on Customer Deposits	Sch. 1R	34,768
14			
15	AFUDC Interest credit	WP 1-2	<u>(659,575)</u>
16			
17	Return on Rate Base		<u>\$ 29,165,421</u>
18			
19	Total Rate Base	Sch. 7R	\$ 429,732,371
20			
21	Rate of Return on Rate Base		6.79%
22			
23	Interest Expense	Sch. 9R, Sch. 7R	7,004,638
24			
25			
26	Return on Equity		<u>\$ 22,160,784</u>
27			
28	Rate of Return on Equity		8.67%
29			
30	Note:		
31	1. Twelve months ended September 30, 2021		

Tennessee Distribution System
Computation of State Excise and Federal Income Taxes for Sch 10
Twelve Months Ended September 30, 2021

Line	Description	Tax Rate	Test Year
	(a)	(b)	(c)
1	Net Operating Income Before Income Tax		\$ 38,128,986
2			
3	Interest Deduction		<u>7,092,411</u>
4			
5	Equity Portion of Return		\$ 31,036,575
6			
7	Application of Tax Rate to Equity Return - Tennessee	6.5%	2,017,377
8			
9	Application of Tax Rate to Equity Return - Federal	21%	<u>6,094,032</u>
10			
11	Income Tax Expense		<u><u>\$ 8,111,409</u></u>
12			
13	Less: ITC Amortization		<u>-</u>
14			
15	Total Income Tax Liability		<u><u>\$ 8,111,409</u></u>
16			
17	Note:		
18	1. Twelve months ended September 30, 2021		

Tennessee Distribution System
Computation of State Excise and Federal Income Taxes for Sch 10
Twelve Months Ended September 30, 2021

Line	Description	Tax Rate	Historic Base Period (1)
	(a)	(b)	(c)
1	Net Operating Income Before Income Tax		\$ 36,113,429
2			
3	Interest Deduction		<u>7,004,638</u>
4			
5	Equity Portion of Return		\$ 29,108,791
6			
7	Application of Tax Rate to Equity Return - Tennessee	6.5%	1,892,071
8			
9	Application of Tax Rate to Equity Return - Federal	21%	<u>5,715,511</u>
10			
11	Income Tax Expense		<u><u>\$ 7,607,582</u></u>
12			
13	Less: ITC Amortization		<u>-</u>
14			
15	Total Income Tax Liability		<u><u>\$ 7,607,582</u></u>
16			
17	Note:		
18	1. Twelve months ended September 30, 2021		

Tennessee Distribution System
Proof of Revenues and Calculation of Rates
Historic Test Period Margin at Present Rates
Actual Twelve Months Ended September 30, 2021

Line No.	Description	12 Mths Ended Sep 21		Rates effective Sep 21		12 mths Sep 21	Weather	12 mths Sep 21	12 mths Sep 21	12 mths Sep 21
		Base Count	Volumes Mcf	Monthly Customer chg	Commodity Charge/Mcf	Margin at Sep 21 Rates	Adjustment Volumes Mcf	WNA Adjusted Volumes Mcf	Weather adj Margin at Sep 21 Rates	WNA \$ Adj at Sep 21 Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	RESIDENTIAL									
2	210 Residential Gas Service (Summer)	686,137	1,110,233	\$18.00	\$1.409	13,914,785	-	1,110,233	13,914,785	-
3	210 Residential Gas Service (Winter) (weather sensitive)	954,893	7,273,841	\$20.00	\$1.409	29,346,702	400,934	7,674,775	29,911,618	564,916
4	210 Residential Gas Service Senior Citizen (Summer)	362	308	\$0.00	\$1.409	434	-	308	434	-
5	210 Residential Gas Service Senior Citizen (Winter) (weather sensitive)	527	3,517	\$0.00	\$1.409	4,955	-	3,517	4,955	-
6	211 Residential/Sm. Commercial/Industrial Heating & Cooling	-	-	\$16.75	\$0.872	-	-	-	-	-
7	Total Residential	1,641,919	8,387,899			43,266,876	400,934	8,788,833	43,831,792	564,916
8										
9	COMMERCIAL									
10	211 Residential/Sm. Commercial/Industrial Heating & Cooling	-	-	16.75	0.872	-	-	-	-	-
11	220 Commercial Gas Service (weather sensitive)	208,273	5,627,459	42.00	2.819	24,611,273	195,835	5,823,294	25,163,332	552,059
12	230 Large Commercial Gas Service (weather sensitive)	-	-	455.00	2.475	-	-	-	-	-
13	250 Commercial Interruptible Gas Service	-	-	455.00	-	-	-	-	-	-
14	Block 1 Volumes	-	-	-	1.386	-	-	-	-	-
15	Block 2 Volumes	-	-	-	0.918	-	-	-	-	-
16	Block 3 Volumes	-	-	-	0.425	-	-	-	-	-
17	293 Large Tonnage Air Conditioning Gas Service	12	-	42.00	-	504	-	-	504	-
18	Block 1 Volumes	-	9,291	-	1.386	12,878	-	9,291	12,878	-
19	Block 2 Volumes	-	29	-	0.918	26	-	29	26	-
20	Block 3 Volumes	-	-	-	0.425	-	-	-	-	-
21	Total Commercial	208,285	5,636,779			24,624,682	195,835	5,832,614	25,176,741	552,059
22										
23	INDUSTRIAL									
24	220 Industrial Gas Service (weather sensitive)	3,834	669,662	42.00	2.819	2,048,805	23,304	692,966	2,114,499	65,694
25	230 Large Industrial Gas Service	83	63,360	455.00	2.475	194,581	-	63,360	194,581	-
26	240 DEMAND/COMM GS	-	-	455.00	-	-	-	-	-	-
27	Block 1 Volumes	-	-	-	1.386	-	-	-	-	-
28	Block 2 Volumes	-	-	-	0.918	-	-	-	-	-
29	Block 3 Volumes	-	-	-	0.425	-	-	-	-	-
30	Demand Volumes	-	-	-	18,950	-	-	-	-	-
31	250 Industrial Interruptible Gas Service	185	-	455.00	-	84,175	-	-	84,175	-
32	Block 1 Volumes	-	207,355	-	1.386	287,394	-	207,355	287,394	-
33	Block 2 Volumes	-	666,668	-	0.918	612,001	-	666,668	612,001	-
34	Block 3 Volumes	-	181,317	-	0.425	77,060	-	181,317	77,060	-
35	250/240/280 Industrial/Demand/Economic Dev	-	-	455.00	-	-	-	-	-	-
36	Block 1 Volumes	-	-	-	1.386	-	-	-	-	-
37	Block 1 Volumes @ Discount Rate	-	-	-	1.040	-	-	-	-	-
38	Block 2 Volumes	-	-	-	0.918	-	-	-	-	-
39	Block 2 Volumes @ Discount Rate	-	-	-	0.689	-	-	-	-	-
40	Block 3 Volumes	-	-	-	0.425	-	-	-	-	-
41	Block 3 Volumes @ Discount Rate	-	-	-	0.319	-	-	-	-	-
42	Demand Volumes	-	-	-	18,950	-	-	-	-	-
43	Demand Volumes @ Discount Rate	-	-	-	14,213	-	-	-	-	-
44	280/250 Economic Development Gas Service	12	-	455.00	-	5,460	-	-	5,460	-
45	Block 1 Volumes	-	-	-	1.386	-	-	-	-	-
46	Block 1 Volumes @ Discount Rate	-	26,175	-	1.040	27,208	-	26,175	27,208	-
47	Block 2 Volumes	-	-	-	0.918	-	-	-	-	-
48	Block 2 Volumes @ Discount Rate	-	39,803	-	0.689	27,405	-	39,803	27,405	-
49	Block 3 Volumes	-	-	-	0.425	-	-	-	-	-
50	Block 3 Volumes @ Discount Rate	-	-	-	0.319	-	-	-	-	-
51	292 Cogeneration, CNG, Prime Movers Service	12	-	42.00	-	504	-	-	504	-
52	Block 1 Volumes	-	3,514	-	1.386	4,871	-	3,514	4,871	-
53	Block 2 Volumes	-	-	-	0.918	-	-	-	-	-
54	Block 3 Volumes	-	-	-	0.425	-	-	-	-	-
55	Total Industrial	4,126	1,857,854			3,369,464	23,304	1,881,158	3,435,158	65,694
56										
57	PUBLIC AUTHORITY									
58	211 Residential/Sm. Commercial/Industrial Heating & Cooling	-	-	16.75	\$0.872	-	-	-	-	-
59	221 Experimental School Gas Service	36	21,513	42.00	1.369	30,964	749	22,262	31,988	1,025
60	225 Public Authority Gas Service (Sr. Citizen) (Summer)	-	-	0.00	1.409	-	-	-	-	-
61	225 Public Authority Gas Service (Sr. Citizen) (Winter)	-	-	0.00	1.409	-	-	-	-	-
62	225 Public Authority Gas Service (Summer)	3,268	5,113	18.00	1.409	66,029	-	5,113	66,029	-
63	225 Public Authority Gas Service (Winter)	4,767	25,498	20.00	1.409	131,267	1,463	26,962	133,329	2,062
64	Total Public Authority	8,071	52,125			228,260	2,212	54,337	231,346	3,087
65										
66	TRANSPORTATION									
67	260 - TRANSP (220 SML COM/INDG)	120	128,509	455.00	2.819	416,866	-	128,509	416,866	-
68	260 - TRANSP (230 LRG COM/INDG)	516	1,441,254	455.00	2.475	3,801,883	-	1,441,254	3,801,883	-
69	260 - TRANSP (240 DEMAND)	75	-	455.00	-	34,125	-	0	34,125	-
70	Block 1 Volumes	-	150,248	-	1.386	208,244	-	150,248	208,244	-
71	Block 2 Volumes	-	408,882	-	0.918	375,354	-	408,882	375,354	-
72	Block 3 Volumes	-	-	-	0.425	0	-	0	0	-
73	Demand Volumes	-	26,838	-	18,950	508,586	-	26,838	508,586	-
74	260 - TRANSP (250 OPT GS)	648	-	455.00	-	294,840	-	0	294,840	-
75	Block 1 Volumes	-	1,243,979	-	1.386	1,724,155	-	1,243,979	1,724,155	-
76	Block 2 Volumes	-	5,253,351	-	0.918	4,822,576	-	5,253,351	4,822,576	-
77	Block 3 Volumes	-	215,826	-	0.425	91,726	-	215,826	91,726	-
78	260 - TRANSP (280/240 ECON DEV/DEMAND)	-	-	455.00	-	0	-	0	0	-
79	Block 1 Volumes	-	-	-	1.386	0	-	0	0	-
80	Block 1 Volumes @ Discount Rate	-	-	-	1.040	0	-	0	0	-
81	Block 2 Volumes	-	-	-	0.918	0	-	0	0	-
82	Block 2 Volumes @ Discount Rate	-	-	-	0.689	0	-	0	0	-
83	Block 3 Volumes	-	-	-	0.425	0	-	0	0	-
84	Block 3 Volumes @ Discount Rate	-	-	-	0.319	0	-	0	0	-
85	Demand Volumes	-	-	-	18,950	0	-	0	0	-
86	Demand Volumes @ Discount Rate	-	-	-	14,213	0	-	0	0	-
87	260 - TRANSP (280/250 ECON DEV - OPT GS)	-	-	455.00	-	0	-	0	0	-
88	Block 1 Volumes	-	-	-	1.386	0	-	0	0	-
89	Block 1 Volumes @ Discount Rate	-	-	-	1.040	0	-	0	0	-
90	Block 2 Volumes	-	-	-	0.918	0	-	0	0	-
91	Block 2 Volumes @ Discount Rate	-	-	-	0.689	0	-	0	0	-
92	Block 3 Volumes	-	-	-	0.425	0	-	0	0	-
93	Block 3 Volumes @ Discount Rate	-	-	-	0.319	0	-	0	0	-
94	SPECIAL CONTRACTS	24	2,952,420			977,625	-	2,952,420	977,625	-
95	Total Transportation	1,383	11,794,469			13,255,980	0	11,794,469	13,255,980	0
96										
97	TOTALS	1,863,784	27,729,127			\$84,745,261	622,285	28,351,411	\$85,931,017	\$1,185,756
98										
99	Other					125,495			0	
100	4870 - Forfeited Discount					(\$200)			(\$200)	
101	4880 - Miscellaneous Service charges					\$51,056			51,056	
102	4960 Tax Reform Cost of Service Reserve					\$1,043,815			0	
103	TOTAL MARGIN REVENUES					<u>\$85,965,427</u>			<u>\$85,961,873</u>	

										210,211,225 220,221,230C		0.00% 0.00%							
Line No.	Description	12 Mths Ended Sep 21		Rates effective Sep 21		12 mths Sep 21 Weather adj Margin at Sep 21 Rates	N O T E	Customer Changes at Sep 21 Rates		Customer Growth		Declining Usage Volumes Mcf	Adjusted Base Count	Adjusted Volumes Mcf	Total Adjusted Margin Rev				
		Base Count	Weather Adj. Vol Mcf	Monthly Customer chg	Commodity Charge/Mcf			Base Count	Volumes Mcf	Base Count	Volumes Mcf								
1	RESIDENTIAL	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)				
2	210 Residential Gas Service (Summer)	686,137	1,110,233		\$18.00	\$1,409	\$13,914,785			0	0	0	686,137	1,110,233	\$13,914,785				
3	210 Residential Gas Service (Winter) (weather sensitive)	954,693	7,674,775		\$20.00	\$1,409	29,911,618			0	0	0	954,693	7,674,775	29,911,618				
4	210 Residential Gas Service Senior Citizen (Summer)	362	308		\$0.00	\$1,409	434			0	0	0	362	308	434				
5	210 Residential Gas Service Senior Citizen (Winter) (weather sensitive)	527	3,517		\$0.00	\$1,409	4,955			0	0	0	527	3,517	4,955				
6	211 Residential/Sm. Commercial/Industrial Heating & Cooling Service	0	0		\$16.75	\$0.872	0			0	0	0	0	0	0				
7	Total Residential	1,641,919	8,788,833				43,831,792	0	0	0	0	0	1,641,919	8,788,833	43,831,792				
8																			
9	COMMERCIAL																		
10	211 Residential/Sm. Commercial/Industrial Heating & Cooling Service	0	0		16.75	0.872	0			0	0	0	0	0	0				
11	220 Commercial Gas Service (weather sensitive)	208,273	5,823,294		42.00	2,819	25,163,332			0	0	0	208,273	5,823,294	25,163,332				
12	230 Large Commercial Gas Service (weather sensitive)	0	0		455.00	2,475	0			0	0	0	0	0	0				
13	250 Commercial Interruptible Gas Service	0	0		455.00	0	0			0	0	0	0	0	0				
14	Block 1 Volumes		0			1,386	0			0	0	0	0	0	0				
15	Block 2 Volumes		0			0,918	0			0	0	0	0	0	0				
16	Block 3 Volumes		0			0,425	0			0	0	0	0	0	0				
17	293 Large Tonnage Air Conditioning Gas Service	12			42.00		504						12	0	504				
18	Block 1 Volumes		9,291			1,386	12,878						0	9,291	12,878				
19	Block 2 Volumes		29			0,918	26						0	29	26				
20	Block 3 Volumes		0			0,425	0						0	0	0				
21	Total Commercial	208,285	5,832,614				25,176,741	0	0	0	0	0	208,285	5,832,614	25,176,741				
22																			
23	INDUSTRIAL																		
24	220 Industrial Gas Service (weather sensitive)	3,834	692,966		42.00	2,819	2,114,499			0	0		3,834	692,966	2,114,499				
25	230 Large Industrial Gas Service	83	63,360		455.00	2,475	194,581						83	63,360	194,581				
26	240 DEMAND/COMM GS	0	0		455.00	0	0						0	0	0				
27	Block 1 Volumes		0			1,386	0						0	0	0				
28	Block 2 Volumes		0			0,918	0						0	0	0				
29	Block 3 Volumes		0			0,425	0						0	0	0				
30	Demand Volumes		0			18,950	0						0	0	0				
31	250 Industrial Interruptible Gas Service	185			455.00		84,175						185	0	84,175				
32	Block 1 Volumes		207,355			1,386	287,394						0	207,355	287,394				
33	Block 2 Volumes		666,668			0,918	612,001						0	666,668	612,001				
34	Block 3 Volumes		181,317			0,425	77,060						0	181,317	77,060				
35	250/240/280 Industrial/Demand/Economic Dev	0	0		455.00	0	0						0	0	0				
36	Block 1 Volumes		0			1,386	0						0	0	0				
37	Block 1 Volumes @ Discount Rate		0			1,040	0						0	0	0				
38	Block 2 Volumes		0			0,918	0						0	0	0				
39	Block 2 Volumes @ Discount Rate		0			0,689	0						0	0	0				
40	Block 3 Volumes		0			0,425	0						0	0	0				
41	Block 3 Volumes @ Discount Rate		0			0,319	0						0	0	0				
42	Demand Volumes		0			18,950	0						0	0	0				
43	Demand Volumes @ Discount Rate		0			14,213	0						0	0	0				
44	280/250 Economic Development Gas Service	12			455.00		5,460						12	0	5,460				
45	Block 1 Volumes		0			1,386	0						0	0	0				
46	Block 1 Volumes @ Discount Rate		26,175			1,040	27,208						0	26,175	27,208				
47	Block 2 Volumes		0			0,918	0						0	0	0				
48	Block 2 Volumes @ Discount Rate		39,803			0,689	27,405						0	39,803	27,405				
49	Block 3 Volumes		0			0,425	0						0	0	0				
50	Block 3 Volumes @ Discount Rate		0			0,319	0						0	0	0				
51	292 Cogeneration, CNG, Prime Movers Service	12			42.00		504						12	0	504				
52	Block 1 Volumes		3,514			1,386	4,871						0	3,514	4,871				
53	Block 2 Volumes		0			0,918	0						0	0	0				
54	Block 3 Volumes		0			0,425	0						0	0	0				
55	Total Industrial	4,126	1,881,158				3,435,158	0	0	0	0	0	4,126	1,881,158	3,435,158				
56																			
57	PUBLIC AUTHORITY																		
58	211 Residential/Sm. Commercial/Industrial Heating & Cooling Service	0	0		16.75	0.872	0						0	0	0				
59	221 Experimental School Gas Service	36	22,262		42.00	1,369	31,988			0	0		36	22,262	31,988				
60	225 Public Authority Gas Service (Sr. Citizen) (Summer)	0	0		0.00	1,409	0						0	0	0				
61	225 Public Authority Gas Service (Sr. Citizen) (Winter) (weather sensitive)	0	0		0.00	1,409	0						0	0	0				
62	225 Public Authority Gas Service (Summer)	3,268	5,113		18.00	1,409	66,029			0	0		3,268	5,113	66,029				
63	225 Public Authority Gas Service (Winter) (weather Sensitive)	4,767	26,962		20.00	1,409	133,329			0	0		4,767	26,962	133,329				
64	Total Public Authority	8,071	54,337				231,346	0	0	0	0	0	8,071	54,337	231,346				
65																			
66	TRANSPORTATION																		
67	260 - TRANSP (220 SML COM/INDG)	120	128,509		455.00	2,819	416,866						120	128,509	416,866				
68	260 - TRANSP (230 LRG COM/INDG)	516	1,441,254		455.00	2,475	3,801,883						516	1,441,254	3,801,883				
69	260 - TRANSP (240 DEMAND)	75			455.00	0	34,125						75	0	34,125				
70	Block 1 Volumes		150,248			1,386	208,244						0	150,248	208,244				
71	Block 2 Volumes		408,882			0,918	375,354						0	408,882	375,354				
72	Block 3 Volumes		0			0,425	0						0	0	0				
73	Demand Volumes		26,838			18,950	508,586						0	26,838	508,586				
74	260 - TRANSP (250 OPT GS)	648			455.00		294,840						648	0	294,840				
75	Block 1 Volumes		1,243,979			1,386	1,724,155						0	1,243,979	1,724,155				
76	Block 2 Volumes		5,253,351			0,918	4,822,576						0	5,253,351	4,822,576				
77	Block 3 Volumes		215,826			0,425	91,726						0	215,826	91,726				
78	260 - TRANSP (280/240 ECON DEV/DEMAND)	-			455.00	0	0						0	0	0				
79	Block 1 Volumes		0			1,386	0						0	0	0				
80	Block 1 Volumes @ Discount Rate		0			1,040	0						0	0	0				
81	Block 2 Volumes		0			0,918	0						0	0	0				
82	Block 2 Volumes @ Discount Rate		0			0,689	0						0	0	0				
83	Block 3 Volumes		0			0,425	0						0	0	0				
84	Block 3 Volumes @ Discount Rate		0			0,319	0						0	0	0				
85	Demand Volumes		0			18,950	0						0	0	0				
86	Demand Volumes @ Discount Rate		0			14,213	0						0	0	0				
87	260 - TRANSP (280/250 ECON DEV - OPT GS)	-			455.00	0	0						0	0	0				
88	Block 1 Volumes		0			1,386	0						0	0	0				
89	Block 1 Volumes @ Discount Rate		0			1,040	0						0	0	0				
90	Block 2 Volumes		0			0,918	0						0	0	0				
91	Block 2 Volumes @ Discount Rate		0			0,689	0						0	0	0				
92	Block 3 Volumes		0			0,425	0						0	0	0				
93	Block 3 Volumes @ Discount Rate		0			0,319	0						0	0	0				
94	SPECIAL CONTRACTS	24	2,952,420				977,625						24	2,952,420	977,625				
95	Total Transportation	1,383	11,794,469				13,255,980	0	0	0	0	0	1,383	11,794,469	13,255,980				
96																			
97	TOTALS	1,863,784	28,351,411				\$85,931,017	0	0	0	0	0	1,863,784	28,351,411	\$85,931,017				
98																			
99	4870 - Forfeited Discount						(200)								(\$200)				
100	4880 - Miscellaneous Service charges						51,056								51,056				
101	TOTAL MARGIN REVENUES						\$85,981,873								\$85,981,873				

Tennessee Distribution System
Proof of Revenues and Calculation of Rates
Rate Design for Rate Effective Year
Twelve Months Ended September 30, 2021

Additional Revenue: 2,269,523

Line No.		Rates effective Sep 21		Adjusted Base	Adjusted Volumes	Total	Cust	Commodity	Cust	Commodity	%	Allocated	Proposed	Proposed	Proposed	Proposed		Cust	Commodity	%
	Description	Monthly Customer chg	Commodity Charge/Mcf	Count	Mcf	Adjusted Margin Rev	Charge Rev	Charge Rev	Charge %	Charge %	of Total Rev	Amount of Increase	Cust Charge	Commodity Charge	Cust Rev	Commodity Rev	Total	Charge %	Charge %	of Total Rev
(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
1	Rate Schedule 210/225																			
2	210/225 SUMMER	\$18.00	\$1.409	689,405	1,115,347	\$13,980,814	\$12,409,290	\$1,571,524					18.70	1.411	\$12,891,874	\$1,574,298	14,466,172			
3	210/225 WINTER (weather sensitive)	\$20.00	\$1.409	959,660	7,701,737	\$30,044,947	\$19,193,200	\$10,851,747					20.70	1.411	\$19,864,962	\$10,870,906	30,735,868			
4	210/225 SR CIT	\$0.00	\$1.409	889	3,825	\$5,389	\$0	\$5,389					0.00	1.411	\$0	\$5,398	5,398			
5	Total 210/225			1,649,954	8,820,908	\$44,031,149	\$31,602,490	\$12,428,659	72%	28%	51.83%	1,176,288			\$32,756,836	\$12,450,602	\$45,207,438	72%	28%	51.83%
6																				
7	Rate Schedule 211																			
8	211 HVAC	\$16.75	\$0.872	0	0	\$0	\$0	\$0	0%	0%	0.00%	0	16.75	0.872	\$0	\$0	\$0	0%	0%	0.00%
9																				
10	Rate Schedule 220																			
11	220 Commercial / Industrial Gas Service	\$42.00	\$2.819	212,107	6,516,260	\$27,277,831	\$8,908,494	\$18,369,337	33%	67%			44.00	2.866	\$9,332,708	\$18,677,704	\$28,010,412	33%	67%	
12	220 Transportation	\$455.00	\$2.819	120	128,509	\$416,866	\$54,600	\$362,266	13%	87%			465.00	2.866	\$55,800	\$368,347	\$424,147	13%	87%	
13	Total 220			212,227	6,644,769	\$27,694,697	\$8,963,094	\$18,731,603	32%	68%	32.60%	739,861			\$9,388,508	\$19,046,051	\$28,434,559	33%	67%	32.60%
14																				
15	Rate Schedule 221																			
16	221 Experimental School Gas Service	\$42.00	\$1.369	36	22,262	\$31,988	\$1,512	\$30,476	5%	95%	0.04%	855	44.00	1.404	\$1,584	\$31,259	\$32,843	5%	95%	0.04%
17																				
18	Rate Schedule 230																			
19	230 Large Commercial / Industrial Gas Service	\$455.00	\$2.475	83	63,360	\$194,581	\$37,765	\$156,816	19%	81%			465.00	2.542	\$38,595	\$161,060	\$199,655	19%	81%	
20	230 Transportation	\$455.00	\$2.475	516	1,441,254	\$3,801,883	\$234,780	\$3,567,103	6%	94%			465.00	2.542	\$239,940	\$3,663,635	\$3,903,575	6%	94%	
21	Total 230			599	1,504,614	\$3,996,465	\$272,545	\$3,723,920	7%	93%	4.70%	106,765			\$278,535	\$3,824,695	\$4,103,230	7%	93%	4.70%
22																				
23	Rate Schedule 240/250/280/292/293																			
24	240 Demand/Commodity Gas Service	\$455.00		75		\$34,125	\$34,125						465.00		\$34,875		\$34,875			
25	Block 1 Volumes		\$1.386		150,248	\$208,244		\$208,244						1.425		\$214,166	\$214,166			
26	Block 2 Volumes		\$0.918		408,882	\$375,354		\$375,354						0.944		\$386,026	\$386,026			
27	Block 3 Volumes		\$0.425		0	\$0		\$0						0.437		\$0	\$0			
28	Demand Volumes		\$18.950		26,838	\$508,586		\$508,586						19.000		\$509,928	\$509,928			
29	250 Interruptible Gas Service	\$455.00		833		\$379,015							465.00		\$387,345		\$387,345			
30	Block 1 Volumes		\$1.386		1,451,334	\$2,011,549		\$2,011,549						1.425		\$2,068,749	\$2,068,749			
31	Block 2 Volumes		\$0.918		5,920,019	\$5,434,577		\$5,434,577						0.944		\$5,589,090	\$5,589,090			
32	Block 3 Volumes		\$0.425		397,142	\$168,785		\$168,785						0.437		\$173,584	\$173,584			
33	280 ECON DEV - OPT GS	\$455.00		12		\$5,460							465.00		\$5,580		\$5,580			
34	Block 1 Volumes		\$1.386		0	\$0		\$0						1.425		\$0	\$0			
35	Block 1 Volumes @ Discount Rate		\$1.040		26,175	\$27,208		\$27,208						1.069		\$27,982	\$27,982			
36	Block 2 Volumes		\$0.918		0	\$0		\$0						0.944		\$0	\$0			
37	Block 2 Volumes @ Discount Rate		\$0.689		39,803	\$27,405		\$27,405						0.708		\$28,184	\$28,184			
38	Block 3 Volumes		\$0.425		0	\$0		\$0						0.437		\$0	\$0			
39	Block 3 Volumes @ Discount Rate		\$0.32		0	\$0		\$0						0.328		\$0	\$0			
40	292 Cogeneration, CNG, Prime Movers Service	\$42.00		12		\$504							44.00		\$528		\$528			
41	Block 1 Volumes		\$1.386		3,514	\$4,871		\$4,871						1.425		\$5,009	\$5,009			
42	Block 2 Volumes		\$0.918		0	\$0		\$0						0.944		\$0	\$0			
43	Block 3 Volumes		\$0.425		0	\$0		\$0						0.437		\$0	\$0			
44	293 Large Tonnage Air Conditioning Gas Service	\$42.00		12		\$504							44.00		\$528		\$528			
45	Block 1 Volumes		\$1.386		9,291	\$12,878		\$12,878						1.425		\$13,244	\$13,244			
46	Block 2 Volumes		\$0.918		29	\$26		\$26						0.944		\$27	\$27			
47	Block 3 Volumes		\$0.425		0	\$0		\$0						0.437		\$0	\$0			
48	Total 240/250/280/292/293			944	8,433,277	\$9,199,092	\$419,608	\$8,779,484	5%	95%	10.83%	245,753			\$428,856	\$9,015,989	\$9,444,845	5%	95%	10.83%
49																				
50	TOTALS			1,863,760	25,425,830	\$84,953,392	\$41,259,249	\$43,694,143	49%	51%	100.00%	2,269,523			\$42,854,319	\$44,368,596	\$87,222,915	49%	51%	100.00%

Atmos Energy Corp - Tennessee Distribution System
Proof of Revenues and Calculation of Rates
Summary Of Present And Proposed Rates
For the Rate Effective Year

	<u>Current Rate</u> Monthly	<u>Proposed Rate</u> Monthly
Sales and Transportation Revenues:		
210 Residential Gas Service (WINTER)		
Customer Charge	\$20.00	\$20.70
Commodity Charge	\$1.409	\$1.411
210 Residential Gas Service (SUMMER)		
Customer Charge	\$18.00	\$18.70
Commodity Charge	\$1.409	\$1.411
211 Residential & Small Commercial/Industrial Heating & Cooling		
Customer Charge	\$16.75	\$16.75
Commodity Charge	\$0.872	\$0.872
220 Commercial & Industrial Gas Service		
Customer Charge	\$42.00	\$44.00
Commodity Charge	\$2.819	\$2.866
221 Experimental School Gas Service		
Customer Charge	\$42.00	\$44.00
Commodity Charge	\$1.369	\$1.404
225 Public Housing Authority Gas Service (WINTER)		
Customer Charge	\$20.00	\$20.70
Commodity Charge	\$1.409	\$1.411
225 Public Housing Authority Gas Service (SUMMER)		
Customer Charge	\$18.00	\$18.70
Commodity Charge	\$1.409	\$1.411
230 Large Commercial & Industrial Gas Service		
Customer Charge	\$455.00	\$465.00
Commodity Charge	\$2.475	\$2.542
240 Demand/Commodity Gas Service		
Customer Charge	\$455.00	\$465.00
1 - 2,000 Mcf	\$1.386	\$1.425
Next 48,000 Mcf	\$0.918	\$0.944
Over 50,000 Mcf	\$0.425	\$0.437
Demand Charge	\$18.950	\$19.000
250 Interruptible Gas Service		
Customer Charge	\$455.00	\$465.00
1 - 2,000 Mcf	\$1.386	\$1.425
Next 48,000 Mcf	\$0.918	\$0.944
Over 50,000 Mcf	\$0.425	\$0.437
260 Transportation Service / 250 Interruptible Gas Service		
Customer Charge	\$455.00	\$465.00
1 - 2,000 Mcf	\$1.386	\$1.425
Next 48,000 Mcf	\$0.918	\$0.944
Over 50,000 Mcf	\$0.425	\$0.437
260 Transportation Service / 220 Commercial & Industrial Gas Service		
Customer Charge	\$455.00	\$465.00
Commodity Charge	\$2.819	\$2.866
260 Transportation Service / 230 Large Commercial & Industrial Gas Service		
Customer Charge	\$455.00	\$465.00
Commodity Charge	\$2.475	\$2.542
Schedule 280 Economic Development Gas Service		
Customer Charge	\$455.00	\$465.00
1 - 2,000 Mcf	\$1.386	\$1.425
1 - 2,000 Mcf @ Discount Rate	\$1.040	\$1.069
Next 48,000 Mcf	\$0.918	\$0.944
Next 48,000 Mcf @ Discount Rate	\$0.689	\$0.708
Over 50,000 Mcf	\$0.425	\$0.437
Over 50,000 Mcf @ Discount Rate	\$0.319	\$0.328
Schedule 292 Cogeneration, CNG. Prime Movers, Fuel Cell Service		
Customer Charge	\$42.00	\$44.00
1 - 2,000 Mcf	\$1.386	\$1.425
Next 48,000 Mcf	\$0.918	\$0.944
Over 50,000 Mcf	\$0.425	\$0.437
Schedule 293 Large Tonnage Air Conditioning Gas Service		
Customer Charge	\$42.00	\$44.00
1 - 2,000 Mcf	\$1.386	\$1.425
Next 48,000 Mcf	\$0.918	\$0.944
Over 50,000 Mcf	\$0.425	\$0.437

Atmos Energy Corporation
Revenue Deficiency (Surplus)
Twelve Months Ended September 30, 2021

Line No.		Company	Reference
1	Rate Base	446,063,594	See 2RB
2	Operating Income at Present Rates	30,676,571	See 3 IS
3	Earned Rate of Return (L 2 / L 1)	6.88%	
4	Fair Rate of Return	7.53%	See 8 CC
5	Required Operating Income (L 1 x L 4)	33,588,589	
6	Operating Income Deficiency (Surplus) (L 5 - L 2)	2,912,018	
7	Gross Revenue Conversion Factor	1.365900	See 7 GU
8	Revenue Deficiency (Surplus)	3,977,525	

Atmos Energy Corporation
Rate Base
Twelve Months Ended September 30, 2021

Line No.		Company	Reference
1	Utility Plant in Service	752,763,449	Sch 7, Col (d), Ln 1
2	Construction Work in Progress	10,767,732	Sch 7, Col (d), Ln 5
3	Materials and Supplies / Storage Gas	4,154,984	Sch 7, Col (d), Ln 11
4	Working Capital/Deferred Rate Case	1,998,664	Sch 7, Col (d), Ln 9
5	Net Elimination of Intercompany Leased Property	6,253,167	Sch 7, Col (d), Ln 27
6	Deferred Pension Regulated Asset	(23,297,122)	Sch 7, Col (d), Ln 13
7	Total Additions	<u>752,640,874</u>	
	Deductions:		
8	Accumulated Depreciation	236,585,801	Sch 7, Col (d), Ln 3
9	Customer Deposits	1,069,783	Sch 7, Col (d), Ln 19
10	Contributions and Advances in Aid of Construction	20,280	Sch 7, Col (d), Ln 17
11	Accumulated Deferred Tax-Accel. Depreciation	61,668,567	Sch 7, Col (d), Ln 15
12	Accrued Interest on Customer Deposits	14,291	Sch 7, Col (d), Ln 21
13	Adjustment for Capitalized Incentive Compensation	7,218,558	
14	Total Deductions	<u>306,577,280</u>	
15	Rate Base	<u>446,063,594</u>	

Atmos Energy Corporation
Income Statement
Twelve Months Ended September 30, 2021

Line No.		Company	Reference
1	Revenues - Sales, forfeited discounts & other	141,610,603	Sch 1, Col (c), Ln 20
2	Cost of Gas	55,628,730	Sch 1, Col (c), Ln 1
3	Gross margin on sales and service	85,981,873	
4	AFUDC	659,575	Sch 1, Col (c), Ln 13
5	Operating Margin	86,641,448	
6	Other Operation and Maintenance	22,348,558	See 4 O&M
7	Interest on Customer Deposits	34,768	Sch 1, Col (c), Ln 13
8	Depreciation and Amortization Exp.	17,174,980	Sch 1, Col (c), Ln 13
9	Taxes Other Than Income	8,295,367	See 5 Tax
10	State Excise Tax	2,017,326	See 6 FIT
11	Federal Income Tax	6,093,877	See 6 FIT
12	Total Operating Expense	55,964,877	
13	Net Operating Income for Return	30,676,571	
14	Plus amortization-Gain	-	
15	Plus adjustments	-	
16	Adjusted Net Operating Income	30,676,571	

Atmos Energy Corporation
Operations and Maintenance Expenses
Twelve Months Ended September 30, 2021

Line No.		Company	Reference
1	Labor	8,073,046	WP 4-1, Excel Col Q, Ln 1
2	Benefits	3,267,307	WP 4-1, Excel Col Q, Ln 2 + Ln 29
3	Employee Welfare	2,506,886	WP 4-1, Excel Col Q, Ln 3
4	Insurance	1,472,039	WP 4-1, Excel Col Q, Ln 4
5	Rent, Maint., & Utilities	1,261,701	WP 4-1, Excel Col Q, Ln 5
6	Vehicles & Equip	413,696	WP 4-1, Excel Col Q, Ln 6
7	Materials and Supplies	506,504	WP 4-1, Excel Col Q, Ln 7
8	Information Technologies	1,457,520	WP 4-1, Excel Col Q, Ln 8
9	Telecom	364,585	WP 4-1, Excel Col Q, Ln 9
10	Marketing	283,581	WP 4-1, Excel Col Q, Ln 10
11	Directors & Shareholders & PR	269,088	WP 4-1, Excel Col Q, Ln 11
12	Dues & Donations	157,815	WP 4-1, Excel Col Q, Ln 12
13	Print & Postage	60,707	WP 4-1, Excel Col Q, Ln 13
14	Travel & Entertainment	141,734	WP 4-1, Excel Col Q, Ln 14
15	Training	67,627	WP 4-1, Excel Col Q, Ln 15
16	Outside Services	6,887,307	WP 4-1, Excel Col Q, Ln 16
17	Provision for Bad Debt	728,391	WP 4-1, Excel Col Q, Ln 17
18	Miscellaneous	(4,225,894)	WP 4-1, Excel Col Q, Ln 18
19	Rate Case Expense	-	WP 4-1, Excel Col Q, Ln 27
20	Elimination of Intercompany Leased Property - Rent	-	WP 3-1, Excel Col C, Ln 14
21	Inclusion of Barnsley Storage Operating Expense	437,170	WP 3-1, Excel Col D, Ln 14
22	Interest Expense	7,092,411	WP 7-7, Excel Col E, Ln 39 & Ln 41
23	Disallowed Items	(1,782,255)	WP 4-1, Excel Col P, Ln 22 : Ln 25
24			
25			
26	Total O&M Expense	<u>29,440,969</u>	

Atmos Energy Corporation
Operations and Maintenance Expense
Twelve Months Ended September 30, 2021

Line No.		Company	Reference
1	Property Taxes	4,961,570	WP 7-6, Col (b), Ln 11+Ln19+Ln23
2	State Gross Receipts Tax	830,996	WP 7-6, Col (b), Ln 12
3	Payroll Taxes	738,123	WP 7-6, Col (b), Ln 13+Ln20+Ln24
4	State Franchise Tax	1,162,400	WP 7-6, Col (b), Ln 14
5	Other General Taxes	22,479	WP 7-7, Col (b), Ln 16
6	TRA Inspection Fee	579,799	WP 7-6, Col (b), Ln 15
7	Total Taxes Other Than Income Taxes	8,295,367	

Atmos Energy Corporation
Federal and Excise Taxes
Twelve Months Ended September 30, 2021

Line No.		Company	Reference
1	Operating Margin	85,981,873	See 3 IS
2	Other Operation and Maintenance	22,348,558	See 3 IS
3	Depreciation and Amortization Expense	17,174,980	See 3 IS
4	Taxes Other Than Income	8,295,367	See 3 IS
5	NOI Before Excise and Income Taxes	38,162,968	
6	less Interest on Customer Deposits	34,768	See 3 IS
7	less Interest Expense	7,092,411	See 3 IS
8	Pre-tax Book Income	31,035,789	
9	Schedule M Adjustments	-	
10	Excise Taxable Income	31,035,789	
11	Excise Tax Rate	6.50%	
12	Excise Tax	2,017,326	
13	Pre-tax Book Income	31,035,789	
14	Excise Tax	2,017,326	
15	Schedule M Adjustments	-	
16	FIT Taxable Income	29,018,462	
17	FIT Rate	21.00%	
18	Subtotal FIT	6,093,877	
19	Less: ITC Amortization	-	
20	Federal Income Tax Expense	6,093,877	

Atmos Energy Corporation
Gross Revenue Conversion Factor
Twelve Months Ended September 30, 2021

Line No.		Amount	Balance	Reference
1	Operating Revenues		1.000000	
2	Add: Forfeited Discounts	(0.000001) A/	<u>(0.000001)</u>	WP 8-2, Excel Col D, Ln 3
3	Balance		0.999999	
4	Uncollectible Ratio	0.008825 B/	<u>0.008825</u>	WP 8-2, Excel Col D, Ln 7
5	Balance		0.991173	
6	State Excise Tax	0.065000 C/	<u>0.064426</u>	WP 8-2, Excel Col D, Ln 11
7	Balance		0.926747	
8	Federal Income Tax	0.210000 C/	<u>0.194617</u>	WP 8-2, Excel Col D, Ln 15
9	Balance		<u>0.732130</u>	
10	Revenue Conversion Factor (1 / Line 9)		<u><u>1.365900</u></u>	

A/ Forfeited discounts on gross revenues = forfeited discounts/gross revenues (excluding forfeited discounts)

B/ Uncollectible expense/Gross margin on sales

C/ Statutory Rate

Atmos Energy Corporation
Cost of Capital
Twelve Months Ended September 30, 2021

Line No.		Ratio	Cost	Weighted Cost	Reference
1	Short Term Debt	0.05%	69.89%	0.0%	Sch 9, Ln 2
2	Long Term Debt	39.36%	3.94%	1.6%	Sch 9, Ln 1
3	Preferred Stock				
4	Stockholder's Equity	<u>60.59%</u>	9.80%	<u>5.9%</u>	Sch 9, Ln 3
5	Total	<u><u>100.00%</u></u> A/		<u><u>7.53%</u></u>	

A/ Should be 100%

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-10
Page 1 of 1

REQUEST:

Provide a comprehensive discussion of the method used to isolate the impact of winter storm Uri on taxable income. Provide supporting documentation identifying the portion of Net Operating Loss ("NOL") associated with the winter storm.

RESPONSE:

Winter Storm Uri resulted in record low temperatures throughout Texas, Kansas and other surrounding jurisdictions during February 11-19th 2021, and extremely higher gas cost for that period.

For book purpose and under normal circumstance, the purchase gas costs are recoverable through purchased gas cost adjustment mechanisms in each state where the Company operates and provides a method of recovering purchased gas costs on an ongoing basis without filing a rate case because they provide a dollar-for-dollar offset to increases or decreases in the cost of natural gas.

However, due to the unprecedented level of purchased gas costs incurred during Winter Storm Uri, the Company is allowed to record a regulatory asset to account for the associated extraordinary costs pursuant to the orders and legislation in Texas and Kansas.

Atmos Energy recorded a total regulatory asset of \$2,101M regulatory asset, of which \$2,012M is to account for the extraordinary costs associated with the Winter Storm Uri as authorized by the Texas RRC and \$89.01M was set up for the state of Kansas as of September 30th, FY2021.

For federal income tax purposes, these costs are treated as deductible when the payments are made, regardless when these gas costs can be recovered. This in turn, result in a large, deferred tax liability that is associated with the Winter Storm Uri Regulatory Asset with a total DTL of 2,101M(gross), with \$2,012M belong to Texas and of \$89.01M belong to Kansas.

Since the Company is in a net operating loss carryforward position, this DTL also generated a corresponding Deferred Tax Asset in federal NOL carryforwards for FY21.

Please see the relied file "p.ADIT TN ARM Fiscal 2021.xlsx" included with the refiled ARM model as Attachment 1 to the Company's response to CPAD 1-09.

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-11
Page 1 of 1

REQUEST:

Provide the underlying calculations supporting the balance of the NOL asset attributable to regulated operations as reflected on Schedule 7-4.

RESPONSE:

Please see Attachment 1.

ATTACHMENT:

CPAD_1-11_Att1- Federal NOL.xlsx

Ellie to send. Sent to rates

Atmos Energy Corporation
TN Docket No. 22-00010
Staff Data Request 1-11
Schedule of NOLs
Cumulative to 9/30/2021

As of 9/30/2017	Prior year carryforward
9/30/2018	FY18 return
9/30/2019	FY19 return
9/30/2020	FY20 Return
9/30/2021	FY21 Provision
	Exclude: Winter Storm URI Fed NOL for TN
	NOL as of 9/30/2021

Regulated Operations	Tax Rate	Regulated Operations
Gross		Tax Effected
(2,263,102,021)	21.00%	(475,251,424)
(466,201,471)	21.00%	(97,902,309)
(214,857,575)	21.00%	(45,120,091)
52,344,589	21.00%	10,992,364
(1,943,873,010)	21.00%	(408,213,332)
2,100,727,995	21.00%	441,152,879
		-
(2,734,961,493)	21.00%	(574,341,914)
21.00%		
(574,341,914)		
ADIT 574,342,040		

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-12
Page 1 of 1

REQUEST:

Given the Company's adjustment to the total company NOL balance to remove impacts on the NOL from non-regulated operations, why is it then not appropriate to remove impacts on the balance of equity associated with non-regulated operating results?

RESPONSE:

The Company's DTA NOL for non-regulated operations is appropriate because it does not relate to the regulated operations for Atmos Energy Corporation in Tennessee or any of the other regulated operations of the Company. Stipulation and Settlement Agreement under Docket No. 14-00146 and subsequent filings have been consistently followed in this regards.

The use of the consolidated capital structure for Atmos Energy Corporation has been used per the terms of the Stipulation and Settlement Agreement in Docket No. 14-00146 without any adjustment for non-regulated operations. Please see Attachment 2, Section IX (particularly page 52-53) for a detailed description regarding the organization and capitalization of Atmos Energy Corporation. Atmos Energy's non-regulated operations have no external financing, while it would be possible to make an adjustment to exclude the equity/intercompany accounts, it would not be reflective of how the overall external financing is managed for the Company.

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-13
Page 1 of 1

REQUEST:

Refer to the Petition's Revenue Requirement Schedules, File <2022 ARM.xls>, WP 7-10 and respond to the following:

- a. Confirm that the balances of Depreciation Expense and Ad Valorem Expense deferred to account 186 otherwise reduce the revenue requirement in the test period if such deferral provisions were not in place.
- b. Confirm that the Deferred Interest balance does not reduce the revenue requirement in the base period as presented by the Company. If this is not confirmed, provide an explanation where the test period interest expense is reduced due to this deferral.
- c. Provide an explanation why the credit to the 400 accounts does not match the charges to account 186.

RESPONSE:

WP 7-10 has been revised in the refiled ARM model to exclude the components of the regulatory asset associated with the Interest Deferrals and RWIP Interest Deferrals per Docket No. 18-00112.

- a. Confirmed.
- b. Confirmed.
- c. The credits to the 400 accounts shown on WP 7-10 contain both the fiscal year 2020 as well as fiscal year 2021 amounts. The fiscal year 2020 credits of \$217,645 were relieved from account 1860 in June 2021 when rates from Docket No. 21-00019 were placed in service.

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-14
Page 1 of 1

REQUEST:

Refer to the Petition's Revenue Requirement Schedules, File <2022 ARM.xls>, WP 9-3 and respond to the following:

- a. Provide the rationale for annualizing interest costs in cell R 33 at September 30, 2021 rather than using the actual interest expenses for the twelve month period ending September 30, 2021. This results in the imputation of interest expense associated with \$600 million in debt in October when the outstanding debt balance was zero.
- b. Provide the analytical support for the recognition of the \$38,645,183 balance of Unamortized Debt Discount within the calculation of the weighted cost of debt.
- c. Explain the amount of "Other Long-Term Real Estate Lease costs" included in the filing. Explain how this is recorded on the books of Atmos Energy Tennessee.

RESPONSE:

- a. The \$600 million in debt referenced was issued on October 1, 2020 and was therefore in place for the entire test period.
- b. Please see Attachment 1.
- c. The amount referenced represents the total of our finance leases that qualify under FASB lease accounting standard 842. The amount is a consolidated total, not specific to Tennessee.

ATTACHMENT:

CPAD_1-14_Att1 - Unamortized Debt Expense Detail_Sept21.xls

Atmos Energy Corporation

Basic Balance Sheet

For the Month Ended September, 2021
Company

	Fiscal 2021 September
Unamortized debt expense - Med Terms Ser A-1 2241-13501	(32,727.76)
Unamortized debt expense - 150MM 6.75% due Jul-28 2241-13521	(380,536.65)
Unamortized debt expense - 200MM 5.95% due Oct-34 2241-13530	(983,739.79)
Unamortized debt expense - 400MM 5.5% due Jun-41 2241-13534	(2,830,549.91)
Unamortized debt expense - 500MM 4.15% due JAN-43 2241-13535	(3,808,796.56)
Unamortized debt expense - 750MM 4.125% due Oct-44 2241-13536	(6,508,329.61)
Unamortized debt expense - 500MM 3.000% due Jun-27 2241-13537	(2,383,640.13)
Unamortized debt expense - 600MM 4.300% due Oct-48 2241-13539	(5,809,339.99)
Unamortized debt expense - 450MM 4.125% due Mar-49 2241-13540	(4,417,856.40)
Unamortized debt expense - 300MM 2.625% due Sep-29 2241-13541	(1,989,333.58)
Unamortized debt expense - 500MM 3.375% due Sep-49 2241-13542	(4,918,148.73)
Unamortized debt expense - 600MM 1.500% due Jan-31 2241-13543	(4,582,184.05)
Total Capitalization	(38,645,183.16)

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-15
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REQUEST:

Regarding elimination of the \$2.2 billion in debt associated with winter storm Uri, did the Company incur commitment fees or related costs associated with securing this debt which was allocated to the Company's Tennessee operations? If so, identify the amount charged to Tennessee operations.

RESPONSE:

The Company did incur fees associated with issuing the \$2.2 billion in debt associated with Winter Storm Uri; however, none of the fees associated with this \$2.2 billion in debt have been included in the Company's ARM filings; therefore, no amount is charged to the Tennessee operations.

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Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
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REQUEST:

Regarding elimination of the \$2.2 billion in debt associated with winter storm Uri, identify the date this debt was secured.

RESPONSE:

The issue date for the \$2.2 billion of debt associated with Winter Storm Uri was March 9, 2021. Please see the Company's response to CAPD 1-01 for the Texas order and the status of the Kansas securitization. The securitization law requires that the Texas Public Finance Authority issue the securitization debt within 180 days of the financing order, which would be early August 2022.

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REQUEST:

Refer to the Petition's Revenue Requirement Schedules, File <2022 ARM.xls>, Schedule 6. Confirm that the Base Period depreciation expense of \$15,666,182 is the balance of depreciation net of depreciation deferrals. Provide documentation demonstrating such deferrals were removed from this depreciation balance.

RESPONSE:

Confirmed. Please see Attachment 1 for detail of accounts and associated sub-accounts that equate to depreciation net of deferrals recorded to sub account 30005.

ATTACHMENT:

CPAD_ 1-17_Att1 - Depreciation Expense Amortization FY21 - Div093.xls

TN Depreciation Deferral
Account 4030 & 4060
FY 2021

Sum of Amount Account	Service Area	Sub Account	GL Journal Category	Month Number												Grand Total
				202010	202011	202012	202101	202102	202103	202104	202105	202106	202107	202108	202109	
4030	093000	09344	SSU Billing	1,100.37	1,095.17	914.99	915.11	879.57	829.20	829.60	830.92	811.17	809.12	808.41	810.76	10,634.39
		30004	Depreciation	29,970.06	29,970.06	29,970.06	29,970.06	29,970.06	29,970.06	29,970.06	29,970.06	29,970.06	29,970.06	29,970.06	29,970.06	359,640.72
		30005	Depreciation	1,139,813.01	1,142,145.45	1,148,335.21	1,151,612.28	1,153,089.14	1,167,985.96	1,174,475.20	1,179,743.20	1,190,444.07	1,208,396.70	1,228,535.27	1,306,656.94	14,191,232.43
			Rate Adjustments	(24,123.83)	(26,230.31)	(32,238.43)	(36,180.73)	(38,211.36)	(42,408.30)	(48,391.98)	(59,726.01)	(41,583.01)	(60,421.58)	(82,775.23)	(164,553.70)	(650,582.37)
		30007	Depreciation	46,096.15	46,032.67	46,420.47	46,625.02	46,337.21	46,792.35	46,859.49	46,674.04	47,185.11	47,185.02	42,560.69	38,686.45	547,454.67
		30031	Depreciation	9,942.84	9,942.84	9,943.52	9,943.52	9,943.52	9,839.34	9,839.34	9,839.34	9,839.34	9,839.34	9,839.34	9,839.34	118,591.62
		30032	Allocation	(5,498.44)	(5,719.10)	(5,554.09)	(5,549.23)	(5,363.69)	(5,572.36)	(5,555.94)	(5,502.91)	(5,617.64)	(5,714.89)	(5,748.55)	(5,636.99)	(67,033.83)
		30041	Depreciation	228.29	228.29	228.29	228.29	228.29	228.29	228.29	228.29	228.29	228.29	182.85	182.85	2,557.72
		30042	Allocation	(223.72)	(223.72)	(223.72)	(223.72)	(223.72)	(223.72)	(223.72)	(223.72)	(223.72)	(179.19)	(179.19)	(179.19)	(2,506.52)
		30051	Depreciation	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	3.72	3.72	3.72	118.88
		30052	Allocation	(7.19)	(7.48)	(7.26)	(7.25)	(7.01)	(7.36)	(7.34)	(7.27)	(2.12)	(2.16)	(2.17)	(2.13)	(66.74)
		30061	Depreciation	22,185.67	22,641.07	23,222.35	23,463.68	23,581.64	23,555.28	23,622.96	23,714.81	23,873.59	24,988.79	25,459.54	30,394.80	290,704.18
		30062	Allocation	(12,268.79)	(13,023.10)	(12,971.17)	(13,094.50)	(12,720.30)	(13,340.18)	(13,339.08)	(13,263.14)	(13,630.32)	(14,514.00)	(14,874.51)	(17,413.27)	(164,452.36)
		41124	Depreciation	42,285.21	41,307.09	44,245.12	44,270.73	44,290.64	43,441.34	42,210.27	42,443.11	53,048.70	53,059.40	53,336.55	56,276.21	560,214.37
		41129	Depreciation	33,423.07	33,422.90	33,573.11	33,613.82	33,728.14	33,728.24	33,732.08	33,751.67	39,806.19	39,806.19	39,818.73	39,918.83	428,322.97
		09344	SSU Billing	3,446.01	3,446.01	3,446.01	3,446.01	3,446.01	3,446.01	3,446.01	3,446.01	3,446.01	3,446.01	3,446.01	3,446.01	41,352.12
4060	093000															
Grand Total				1,286,281.71	1,285,040.84	1,289,222.46	1,289,046.09	1,288,979.14	1,298,276.25	1,297,168.24	1,297,931.40	1,337,598.53	1,336,855.38	1,330,381.52	1,329,400.69	15,666,182.25

Company	Account	Sub Account	Service Area	Month Number	GL Journal Category	Source	Quantity	Amount
050	4030	09344	093000	202010	SSU Billing	GL-Entries	0	\$1,100.37
050	4030	09344	093000	202011	SSU Billing	GL-Entries	0	\$1,095.17
050	4030	09344	093000	202012	SSU Billing	GL-Entries	0	\$914.99
050	4030	09344	093000	202101	SSU Billing	GL-Entries	0	\$915.11
050	4030	09344	093000	202102	SSU Billing	GL-Entries	0	\$879.57
050	4030	09344	093000	202103	SSU Billing	GL-Entries	0	\$829.20
050	4030	09344	093000	202104	SSU Billing	GL-Entries	0	\$829.60
050	4030	09344	093000	202105	SSU Billing	GL-Entries	0	\$830.92
050	4030	09344	093000	202106	SSU Billing	GL-Entries	0	\$811.17
050	4030	09344	093000	202107	SSU Billing	GL-Entries	0	\$809.12
050	4030	09344	093000	202108	SSU Billing	GL-Entries	0	\$808.41
050	4030	09344	093000	202109	SSU Billing	GL-Entries	0	\$810.76
050	4030	30004	093000	202010	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202011	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202012	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202101	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202102	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202103	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202104	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202105	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202106	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202107	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202108	Depreciation	Powerplant	0	\$29,970.06
050	4030	30004	093000	202109	Depreciation	Powerplant	0	\$29,970.06
050	4030	30005	093000	202010	Rate Adjustments	Journal Lines	0	\$67.98
050	4030	30005	093000	202010	Depreciation	Powerplant	0	\$1,139,813.01
050	4030	30005	093000	202010	Rate Adjustments	Powerplant	0	(\$24,291.81)
050	4030	30005	093000	202011	Rate Adjustments	Journal Lines	0	\$0.13
050	4030	30005	093000	202011	Depreciation	Powerplant	0	\$1,142,145.45
050	4030	30005	093000	202011	Rate Adjustments	Powerplant	0	(\$26,230.44)
050	4030	30005	093000	202012	Rate Adjustments	Journal Lines	0	(\$8.43)
050	4030	30005	093000	202012	Depreciation	Powerplant	0	\$1,148,335.21
050	4030	30005	093000	202012	Rate Adjustments	Powerplant	0	(\$32,325.00)
050	4030	30005	093000	202101	Rate Adjustments	Journal Lines	0	\$2.98
050	4030	30005	093000	202101	Depreciation	Powerplant	0	\$1,151,612.28
050	4030	30005	093000	202101	Rate Adjustments	Powerplant	0	(\$36,183.71)
050	4030	30005	093000	202102	Rate Adjustments	Journal Lines	0	\$4.16
050	4030	30005	093000	202102	Depreciation	Powerplant	0	\$1,153,089.14
050	4030	30005	093000	202102	Rate Adjustments	Powerplant	0	(\$38,217.52)
050	4030	30005	093000	202103	Rate Adjustments	Journal Lines	0	(\$63.91)
050	4030	30005	093000	202103	Depreciation	Powerplant	0	\$1,167,985.96
050	4030	30005	093000	202103	Rate Adjustments	Powerplant	0	(\$42,345.29)
050	4030	30005	093000	202104	Rate Adjustments	Journal Lines	0	\$51.31
050	4030	30005	093000	202104	Depreciation	Powerplant	0	\$1,174,475.20
050	4030	30005	093000	202104	Rate Adjustments	Powerplant	0	(\$48,983.29)
050	4030	30005	093000	202105	Rate Adjustments	Journal Lines	0	\$10.37
050	4030	30005	093000	202105	Depreciation	Powerplant	0	\$1,179,743.20
050	4030	30005	093000	202105	Rate Adjustments	Powerplant	0	(\$53,736.38)
050	4030	30005	093000	202106	Rate Adjustments	Journal Lines	0	\$191.37
050	4030	30005	093000	202106	Depreciation	Powerplant	0	\$1,190,444.07
050	4030	30005	093000	202106	Rate Adjustments	Powerplant	0	(\$41,774.38)
050	4030	30005	093000	202107	Rate Adjustments	Journal Lines	0	(\$1,527.06)
050	4030	30005	093000	202107	Depreciation	Powerplant	0	\$1,208,396.70
050	4030	30005	093000	202107	Rate Adjustments	Powerplant	0	(\$58,894.52)
050	4030	30005	093000	202108	Rate Adjustments	Journal Lines	0	\$1,523.69
050	4030	30005	093000	202108	Depreciation	Powerplant	0	\$1,228,535.27
050	4030	30005	093000	202108	Rate Adjustments	Powerplant	0	(\$84,298.92)
050	4030	30005	093000	202109	Rate Adjustments	Journal Lines	0	(\$2,085.80)
050	4030	30005	093000	202109	Depreciation	Powerplant	0	\$1,306,656.94
050	4030	30005	093000	202109	Rate Adjustments	Powerplant	0	(\$161,467.90)
050	4030	30007	093000	202010	Depreciation	Powerplant	0	\$46,096.15
050	4030	30007	093000	202011	Depreciation	Powerplant	0	\$46,032.67
050	4030	30007	093000	202012	Depreciation	Powerplant	0	\$46,420.47
050	4030	30007	093000	202101	Depreciation	Powerplant	0	\$46,625.02
050	4030	30007	093000	202102	Depreciation	Powerplant	0	\$46,337.21
050	4030	30007	093000	202103	Depreciation	Powerplant	0	\$46,792.35
050	4030	30007	093000	202104	Depreciation	Powerplant	0	\$46,859.49
050	4030	30007	093000	202105	Depreciation	Powerplant	0	\$46,674.04
050	4030	30007	093000	202106	Depreciation	Powerplant	0	\$47,185.11
050	4030	30007	093000	202107	Depreciation	Powerplant	0	\$47,185.02
050	4030	30007	093000	202108	Depreciation	Powerplant	0	\$42,560.69
050	4030	30007	093000	202109	Depreciation	Powerplant	0	\$38,686.45
050	4030	30031	093000	202010	Depreciation	Powerplant	0	\$9,942.84
050	4030	30031	093000	202011	Depreciation	Powerplant	0	\$9,942.84
050	4030	30031	093000	202012	Depreciation	Powerplant	0	\$9,943.52
050	4030	30031	093000	202101	Depreciation	Powerplant	0	\$9,943.52
050	4030	30031	093000	202102	Depreciation	Powerplant	0	\$9,943.52
050	4030	30031	093000	202103	Depreciation	Powerplant	0	\$9,839.34
050	4030	30031	093000	202104	Depreciation	Powerplant	0	\$9,839.34
050	4030	30031	093000	202105	Depreciation	Powerplant	0	\$9,839.34
050	4030	30031	093000	202106	Depreciation	Powerplant	0	\$9,839.34
050	4030	30031	093000	202107	Depreciation	Powerplant	0	\$9,839.34
050	4030	30031	093000	202108	Depreciation	Powerplant	0	\$9,839.34
050	4030	30031	093000	202109	Depreciation	Powerplant	0	\$9,839.34
050	4030	30032	093000	202010	Allocation	GL-Entries	0	(\$5,498.44)
050	4030	30032	093000	202011	Allocation	GL-Entries	0	(\$5,719.10)
050	4030	30032	093000	202012	Allocation	GL-Entries	0	(\$5,554.09)
050	4030	30032	093000	202101	Allocation	GL-Entries	0	(\$5,549.23)
050	4030	30032	093000	202102	Allocation	GL-Entries	0	(\$5,363.69)
050	4030	30032	093000	202103	Allocation	GL-Entries	0	(\$5,572.36)
050	4030	30032	093000	202104	Allocation	GL-Entries	0	(\$5,555.94)
050	4030	30032	093000	202105	Allocation	GL-Entries	0	(\$5,502.91)
050	4030	30032	093000	202106	Allocation	GL-Entries	0	(\$5,617.64)

Company	Account	Sub Account	Service Area	Month Number	GL Journal Category	Source	Quantity	Amount
050	4030	30032	093000	202107	Allocation	GL-Entries	0	(\$5,714.89)
050	4030	30032	093000	202108	Allocation	GL-Entries	0	(\$5,748.55)
050	4030	30032	093000	202109	Allocation	GL-Entries	0	(\$5,636.99)
050	4030	30041	093000	202010	Depreciation	Powerplant	0	\$228.29
050	4030	30041	093000	202011	Depreciation	Powerplant	0	\$228.29
050	4030	30041	093000	202012	Depreciation	Powerplant	0	\$228.29
050	4030	30041	093000	202101	Depreciation	Powerplant	0	\$228.29
050	4030	30041	093000	202102	Depreciation	Powerplant	0	\$228.29
050	4030	30041	093000	202103	Depreciation	Powerplant	0	\$228.29
050	4030	30041	093000	202104	Depreciation	Powerplant	0	\$228.29
050	4030	30041	093000	202105	Depreciation	Powerplant	0	\$228.29
050	4030	30041	093000	202106	Depreciation	Powerplant	0	\$182.85
050	4030	30041	093000	202107	Depreciation	Powerplant	0	\$182.85
050	4030	30041	093000	202108	Depreciation	Powerplant	0	\$182.85
050	4030	30041	093000	202109	Depreciation	Powerplant	0	\$182.85
050	4030	30042	093000	202010	Allocation	GL-Entries	0	(\$223.72)
050	4030	30042	093000	202011	Allocation	GL-Entries	0	(\$223.72)
050	4030	30042	093000	202012	Allocation	GL-Entries	0	(\$223.72)
050	4030	30042	093000	202101	Allocation	GL-Entries	0	(\$223.72)
050	4030	30042	093000	202102	Allocation	GL-Entries	0	(\$223.72)
050	4030	30042	093000	202103	Allocation	GL-Entries	0	(\$223.72)
050	4030	30042	093000	202104	Allocation	GL-Entries	0	(\$223.72)
050	4030	30042	093000	202105	Allocation	GL-Entries	0	(\$223.72)
050	4030	30042	093000	202106	Allocation	GL-Entries	0	(\$179.19)
050	4030	30042	093000	202107	Allocation	GL-Entries	0	(\$179.19)
050	4030	30042	093000	202108	Allocation	GL-Entries	0	(\$179.19)
050	4030	30042	093000	202109	Allocation	GL-Entries	0	(\$179.19)
050	4030	30051	093000	202010	Depreciation	Powerplant	0	\$13.00
050	4030	30051	093000	202011	Depreciation	Powerplant	0	\$13.00
050	4030	30051	093000	202012	Depreciation	Powerplant	0	\$13.00
050	4030	30051	093000	202101	Depreciation	Powerplant	0	\$13.00
050	4030	30051	093000	202102	Depreciation	Powerplant	0	\$13.00
050	4030	30051	093000	202103	Depreciation	Powerplant	0	\$13.00
050	4030	30051	093000	202104	Depreciation	Powerplant	0	\$13.00
050	4030	30051	093000	202105	Depreciation	Powerplant	0	\$13.00
050	4030	30051	093000	202106	Depreciation	Powerplant	0	\$3.72
050	4030	30051	093000	202107	Depreciation	Powerplant	0	\$3.72
050	4030	30051	093000	202108	Depreciation	Powerplant	0	\$3.72
050	4030	30051	093000	202109	Depreciation	Powerplant	0	\$3.72
050	4030	30052	093000	202010	Allocation	GL-Entries	0	(\$7.19)
050	4030	30052	093000	202011	Allocation	GL-Entries	0	(\$7.48)
050	4030	30052	093000	202012	Allocation	GL-Entries	0	(\$7.26)
050	4030	30052	093000	202101	Allocation	GL-Entries	0	(\$7.25)
050	4030	30052	093000	202102	Allocation	GL-Entries	0	(\$7.01)
050	4030	30052	093000	202103	Allocation	GL-Entries	0	(\$7.36)
050	4030	30052	093000	202104	Allocation	GL-Entries	0	(\$7.34)
050	4030	30052	093000	202105	Allocation	GL-Entries	0	(\$7.27)
050	4030	30052	093000	202106	Allocation	GL-Entries	0	(\$2.12)
050	4030	30052	093000	202107	Allocation	GL-Entries	0	(\$2.16)
050	4030	30052	093000	202108	Allocation	GL-Entries	0	(\$2.17)
050	4030	30052	093000	202109	Allocation	GL-Entries	0	(\$2.13)
050	4030	30061	093000	202010	Depreciation	Powerplant	0	\$22,185.67
050	4030	30061	093000	202011	Depreciation	Powerplant	0	\$22,641.07
050	4030	30061	093000	202012	Depreciation	Powerplant	0	\$23,222.35
050	4030	30061	093000	202101	Depreciation	Powerplant	0	\$23,463.68
050	4030	30061	093000	202102	Depreciation	Powerplant	0	\$23,581.64
050	4030	30061	093000	202103	Depreciation	Powerplant	0	\$23,555.28
050	4030	30061	093000	202104	Depreciation	Powerplant	0	\$23,622.96
050	4030	30061	093000	202105	Depreciation	Powerplant	0	\$23,714.81
050	4030	30061	093000	202106	Depreciation	Powerplant	0	\$23,873.59
050	4030	30061	093000	202107	Depreciation	Powerplant	0	\$24,988.79
050	4030	30061	093000	202108	Depreciation	Powerplant	0	\$25,459.54
050	4030	30061	093000	202109	Depreciation	Powerplant	0	\$30,394.80
050	4030	30062	093000	202010	Allocation	GL-Entries	0	(\$12,268.79)
050	4030	30062	093000	202011	Allocation	GL-Entries	0	(\$13,023.10)
050	4030	30062	093000	202012	Allocation	GL-Entries	0	(\$12,971.17)
050	4030	30062	093000	202101	Allocation	GL-Entries	0	(\$13,094.50)
050	4030	30062	093000	202102	Allocation	GL-Entries	0	(\$12,720.30)
050	4030	30062	093000	202103	Allocation	GL-Entries	0	(\$13,340.18)
050	4030	30062	093000	202104	Allocation	GL-Entries	0	(\$13,339.08)
050	4030	30062	093000	202105	Allocation	GL-Entries	0	(\$13,263.14)
050	4030	30062	093000	202106	Allocation	GL-Entries	0	(\$13,630.32)
050	4030	30062	093000	202107	Allocation	GL-Entries	0	(\$14,514.00)
050	4030	30062	093000	202108	Allocation	GL-Entries	0	(\$14,874.51)
050	4030	30062	093000	202109	Allocation	GL-Entries	0	(\$17,413.27)
050	4030	41124	093000	202010	Depreciation	Powerplant	0	\$42,285.21
050	4030	41124	093000	202011	Depreciation	Powerplant	0	\$41,307.09
050	4030	41124	093000	202012	Depreciation	Powerplant	0	\$44,245.12
050	4030	41124	093000	202101	Depreciation	Powerplant	0	\$44,270.73
050	4030	41124	093000	202102	Depreciation	Powerplant	0	\$44,290.64
050	4030	41124	093000	202103	Depreciation	Powerplant	0	\$43,441.34
050	4030	41124	093000	202104	Depreciation	Powerplant	0	\$42,210.27
050	4030	41124	093000	202105	Depreciation	Powerplant	0	\$42,443.11
050	4030	41124	093000	202106	Depreciation	Powerplant	0	\$53,048.70
050	4030	41124	093000	202107	Depreciation	Powerplant	0	\$53,059.40
050	4030	41124	093000	202108	Depreciation	Powerplant	0	\$53,336.55
050	4030	41124	093000	202109	Depreciation	Powerplant	0	\$56,276.21
050	4030	41129	093000	202010	Depreciation	Powerplant	0	\$33,423.07
050	4030	41129	093000	202011	Depreciation	Powerplant	0	\$33,422.90
050	4030	41129	093000	202012	Depreciation	Powerplant	0	\$33,573.11
050	4030	41129	093000	202101	Depreciation	Powerplant	0	\$33,613.82
050	4030	41129	093000	202102	Depreciation	Powerplant	0	\$33,728.14
050	4030	41129	093000	202103	Depreciation	Powerplant	0	\$33,728.24

Company	Account	Sub Account	Service Area	Month Number	GL Journal Category	Source	Quantity	Amount
050	4030	41129	093000	202104	Depreciation	Powerplant	0	\$33,732.08
050	4030	41129	093000	202105	Depreciation	Powerplant	0	\$33,751.67
050	4030	41129	093000	202106	Depreciation	Powerplant	0	\$39,806.19
050	4030	41129	093000	202107	Depreciation	Powerplant	0	\$39,806.19
050	4030	41129	093000	202108	Depreciation	Powerplant	0	\$39,818.73
050	4030	41129	093000	202109	Depreciation	Powerplant	0	\$39,918.83
050	4060	09344	093000	2021010	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	2021011	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	2021012	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	2021011	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	2021012	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	202103	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	202104	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	202105	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	202106	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	202107	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	202108	SSU Billing	GL-Entries	0	\$3,446.01
050	4060	09344	093000	202109	SSU Billing	GL-Entries	0	\$3,446.01

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-18
Page 1 of 1

REQUEST:

Refer to the Petition's Revenue Requirement Schedules, File <2022 ARM.xls>, Schedule 8. Provide support for the hard-coded Short Term Debt rate of 80.94% associated with short-term debt. If this is not an error, provide a comprehensive explanation supporting the justification for an 80.94% cost rate for short-term debt.

RESPONSE:

Please see Attachment 1. The short-term rate has been adjusted to 69.89% due to an adjustment to the amortization schedule for debt issuance costs in accordance with ASC 470. This resulted in a decrease of \$740,777 to fiscal 2021 related bank fees. This adjustment is also reflected in the revised ARM model in Attachment 1 to the Company's response to CPAD DR 1-09.

ATTACHMENT:

CPAD_1-18_Att1 - Short-Term Debt Rate.xls

Atmos Energy Corp - Consolidated

Schedule of Debt and Equity
September 30, 2021

Atmos Consolidated Balances				Atmos Consolidated - calc of STD rate		
Line No.	Date	Long-Term Debt**	Short-Term Debt	Equity	12 Month Avg STD Avg Daily Bal	12 Month Avg STD Int Exp & fees
	(a)	(b)	(c)	(d)	(e)	(f)
1 Sep-20		4,531,944,234	0	6,791,203,456		
2 Oct-20		5,124,535,942	0	6,875,466,222	-	405,501
3 Nov-20		5,124,818,909	0	6,868,006,033	-	399,760
4 Dec-20		5,125,033,150	0	7,213,155,664	-	405,501
5 Jan-21		5,125,258,556	0	7,373,460,669	-	405,516
6 Feb-21		5,125,483,885	59,994,400	7,438,802,054	15,000,000	398,490
7 Mar-21		7,316,580,609	0	7,820,925,344	40,645,161	554,528
8 Apr-21		7,317,569,587	0	7,844,770,874	-	348,096
9 May-21		7,318,060,061	0	7,787,132,838	-	355,951
10 Jun-21		7,328,947,454	0	7,773,757,588	-	349,209
11 Jul-21		7,329,538,232	0	7,780,443,380	-	355,951
12 Aug-21		7,330,131,876	24,998,243	7,731,393,336	5,645,161	356,486
13 Sep-21		7,330,656,877	0	7,906,888,837	19,166,667	350,966
14						4,685,956
15						
16 Average		6,263,735,336	6,537,896	7,477,338,946	6,704,749	69.89%

Interest on CP or Interest on Draws on Credit Facility	Commitment Fees on Credit Facility	CA-Effective 09/25/15 to mature 9/25/23 Bank Fees on AEC Credit Facility
30120,30121	30121	30121
Detail of Colm (f) Consolidated Int Exp & Fees		
Int Exp	Commit fees	Utility Bank Admin
-	177,988	227,514
-	172,246	227,514
-	177,988	227,514
-	178,002	227,514
1,867	169,109	227,514
5,600	229,002	319,926
-	202,260	145,835
-	209,002	146,949
-	202,260	146,949
-	209,002	146,949
535	209,002	146,949
1,757	202,260	146,949
9,758.34	2,338,121.51	2,338,076.62
per STD rpts:	4,685,956	

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-19
Page 1 of 1

REQUEST:

Provide the underlying support for the Company's Allowance for Funds Used During Construction ("AFUDC") rate as of September 2021 applied to September's Construction Work in in Progress ("CWIP") balance.

RESPONSE:

Please see Attachment 1.

ATTACHMENT:

CPAD_1-19_Att1 - AFUDC Computation Sep_2021.xls

Atmos Energy Corporation
Computation of Tennessee AFUDC Rate
September 2021

Per 18 CFR Part 201, Gas Plant Instructions, Components of construction costs, item 17.

Line No.	Description	Amounts	References
(a)		(b)	(c)
1	<u>Formulae:</u>		
2			
3	$A_i = s(S/W) + d(D/(D+P+C))(1-S/W)$		
4			
5	$A_e = [1-S/W][p(P/(D+P+C)) + c(C/(D+P+C))]$		
6			
7			
8	<u>Where:</u>		
9			
10	A_i = Gross allowance for borrowed funds used during construction rate.		
11	A_e = Allowance for other funds used during construction rate.		
12			
13	S = Average short-term debt.	\$6,774,194	See Wp S
14	s = Short-term debt interest rate.	80.9607%	See Wp S
15	D = Long-term debt.	\$4,531,944,234	[2]
16	d = Long-term debt interest rate.	4.29%	See Wp L Rate
17	P = Preferred stock	\$0	
18	p = Preferred stock cost rate.	0.00%	
19	C = Common equity	\$6,791,203,456	[2]
20	c = Common equity cost rate.	13.27%	[3]
21	W = Average balance in construction work in progress.	\$459,181,351	See Wp W
22			
23			
24			
25	<u>Results: [1]</u>		
26			
27	$A_i =$ 2.887%		
28			
29	$A_e =$ 7.840%		
30			
31	$A(i+e) =$ 10.728%		
32			
33			

[1] If the short-term debt balance (line 13) is greater than the average balance in construction work in progress only the short-term rate is indicated. (line 14)

[2] Actual Book Balances as of the end of the prior fiscal year.

[3] The latest approved ROE for Tennessee of 9.80%, grossed up at a Tennessee's approved tax rate of 26.

Atmos Energy Corp. - Consolidated
Capital Structure and Proforma Cost of Capital

13 Month Average at September 30, 2020

Line No.	Description	Capital	Ratio	Cost Rate	Proforma Wtd Cost of Capital
	(a)	(b)	(c)	(d)	(e)
Atmos Energy Corp., Consolidated:					
1	Long Term Debt Capital	\$4,353,728,889	40.98%	4.36%	1.79%
2	Short Term Debt	\$25,271,339	0.24%	17.10%	0.04%
3	Equity Capital	\$6,245,652,242	58.78%	10.50%	6.17%
4	Total Capital	<u>\$10,624,652,470</u>	<u>100.00%</u>		<u>8.00%</u>

Atmos Energy Corp. - Consolidated
Capital Structure and Proforma Cost of Capital

September 30, 2020

Line No.	Description	Capital	Ratio	Cost Rate	Proforma Wtd Cost of Capital
	(a)	(b)	(c)	(d)	(e)
Atmos Energy Corp., Consolidated:					
5	Long Term Debt Capital	\$4,531,944,234	40.02%	4.29%	1.72%
6	Short Term Debt	\$0	0.00%	17.10%	0.00%
7	Equity Capital	\$6,791,203,456	59.98%	10.50%	6.30%
8	Total Capital	<u>\$11,323,147,690</u>	<u>100.00%</u>		<u>8.02%</u>

Atmos Energy Corp - Consolidated

Schedule of Debt and Equity
September 30, 2020

Atmos Consolidated Balances				Atmos Consolidated - calc of STD rate			Interest on CP or Interest on Draws on Credit Facility			Commitment Fees on Credit Facility	CA-Effective 09/25/15 to mature 9/25/23 Bank Fees on AEC Credit Facility
Line No.	Date	Long-Term Debt**	Short-Term Debt	Equity	12 Month Avg STD Avg Daily Bal	12 Month Avg STD Int Exp & fees	STD avg rate	30120,30121 Detail of Colm (f) Consolidated Int Exp & Fees			
(a)	(b)	(c)	(d)	(e)	(f)	(g)		Int Exp	Commit fees	Utility Bank Admin	
1 Sep-19	3,529,452,246	464,914,793	5,750,222,025								
2 Oct-19	4,323,929,862	0	5,786,654,551	48,696,774	352,975			90,071	131,821		131,083
3 Nov-19	4,324,112,264	0	5,889,337,249	-	258,652			-	127,569		131,083
4 Dec-19	4,324,334,969	0	6,127,776,288	-	262,904			-	131,821		131,083
5 Jan-20	4,324,453,053	0	6,226,778,984	-	237,063			-	105,980		131,083
6 Feb-20	4,324,629,840	0	6,237,903,335	-	230,226			-	99,143		131,083
7 Mar-20	4,328,996,996	199,923,347	6,304,414,573	51,523,968	336,740			99,677	105,980		131,083
8 Apr-20	4,529,030,709	0	6,333,528,945	61,723,500	400,702			96,788	172,831		131,083
9 May-20	4,529,195,706	0	6,318,537,073	-	469,297			-	178,592		290,705
10 Jun-20	4,531,497,968	0	6,461,470,109	3,333,333	436,494			313	172,831		263,350
11 Jul-20	4,531,685,721	0	6,469,473,585	-	441,338			-	177,988		263,350
12 Aug-20	4,531,858,276	24,998,125	6,496,178,973	5,645,161	442,213			875	177,988		263,350
13 Sep-20	4,531,944,234	0	6,791,203,456	132,333,333	452,148			16,551	172,246		263,350
14					4,320,751			304,274.35	1,754,790.66		2,261,686.38
15											
16 Average	4,358,855,527	53,064,328	6,245,652,242	25,271,339	17.10%			per STD rpts:	4,320,751		

Atmos Energy Corporation

Consolidated Long-Term Debt Outstanding w/ calculation of Effective Interest Rates
September 30, 2020

Atmos Energy Corp., Consolidated:

Line	Debt Series (a)	Issued (b)	Outstanding 9/30/2019 (d)	Outstanding 10/31/2019 (e)	Outstanding 11/30/2019 (f)	Outstanding 12/31/2019 (g)	Outstanding 1/31/2020 (h)	Outstanding 2/29/2020 (i)	Outstanding 3/31/2020 (j)	Outstanding 4/30/2020 (k)	Outstanding 5/31/2020 (l)	Outstanding 6/30/2020 (m)	Outstanding 7/31/2020 (n)
1	9.40% First Mortgage Bond J due May 2021/RET 2005	04/01/91	-	-	-	-	-	-	-	-	-	-	-
2	6.75% Debentures Unsecured due July 2028	07/27/98	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000
3	5.125% Senior Note due Jan 2013	01/13/03	-	-	-	-	-	-	-	-	-	-	-
4	10.43% First Mortgage Bond P due 2017 (eff 2012)	11/01/87	-	-	-	-	-	-	-	-	-	-	-
5	9.75% First Mortgage Bond Q due Apr 2020/RET 2005	04/01/90	-	-	-	-	-	-	-	-	-	-	-
6	9.32% First Mortgage Bond T due June 2021/RET 2005	06/01/91	-	-	-	-	-	-	-	-	-	-	-
7	8.77% First Mortgage Bond U due May 2022/RET 2005	05/01/92	-	-	-	-	-	-	-	-	-	-	-
8	6.67% MTN A1 due Dec 2025	12/15/95	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
9	4.95% Sr Note due 10/15/2014	10/22/04	-	-	-	-	-	-	-	-	-	-	-
10	5.95% Sr Note due 10/15/2034	10/22/04	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000
11	4.3% Sr Note due 10/1/2048	10/2018	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000	600,000,000
12	Sr Note 5.50% Due 06/15/2041	6/10/2011	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000
13	8.50% Sr Note due 3/15/2019	03/23/09	-	-	-	-	-	-	-	-	-	-	-
14	4.15% Sr Note due 1/15/2043	01/15/13	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000
15	4.125% Sr Note due 10/15/2044 (500MM(2014) & 250MM(2017))	10/15/2014	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000	750,000,000
16	3% Sr Note due 6/15/2027	06/2017	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000
17	4.125% Sr Note due 3/15/49	03/2019	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000
18	2.625% Sr Notes Due 2029	10/2019	-	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000	300,000,000
19	3.375% Sr Notes Due 2049	10/2019	-	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000
20	\$200MM 3YR. Term Loan (Established 4/09/20)	04/2020	-	-	-	-	-	-	-	200,000,000	200,000,000	200,000,000	200,000,000
21	October 2020 - Swap Position	04/2020	-	-	-	-	-	-	-	-	-	-	-
22	October 2021 - Swap Position	04/2020	-	-	-	-	-	-	-	-	-	-	-
23	October 2022 - Swap Position	07/2020	-	-	-	-	-	-	-	-	-	-	-
24	October 2024 - Swap Position	07/2020	-	-	-	-	-	-	-	-	-	-	-
25	Subtotal -- Utility Long-Term Debt		\$ 3,560,000,000	\$ 4,360,000,000	\$ 4,360,000,000	\$ 4,360,000,000	\$ 4,360,000,000	\$ 4,360,000,000	\$ 4,360,000,000	\$ 4,560,000,000	\$ 4,560,000,000	\$ 4,560,000,000	\$ 4,560,000,000
26													
27	Other Long-Term Debt												
28	Total Long-Term Debt		<u>3,560,000,000</u>	<u>4,360,000,000</u>	<u>4,360,000,000</u>	<u>4,360,000,000</u>	<u>4,360,000,000</u>	<u>4,360,000,000</u>	<u>4,360,000,000</u>	<u>4,560,000,000</u>	<u>4,560,000,000</u>	<u>4,560,000,000</u>	<u>4,560,000,000</u>
29	Less Unamortized Debt Discount & Debt Premium		\$ 192,885	\$ 732,066	\$ 716,190	\$ 702,843	\$ 689,496	\$ 676,148	\$ 662,801	\$ 649,453	\$ 636,106	\$ 622,758	\$ 609,411
30	Less Unamortized Debt Expense		\$ 30,354,868	\$ 37,831,223	\$ 37,660,377	\$ 37,496,696	\$ 37,333,187	\$ 37,169,678	\$ 37,006,168	\$ 36,842,659	\$ 36,679,149	\$ 36,515,640	\$ 36,352,131
31	Annualized Amortization of T-Lock Settlement, Debt Exp, Debt Disc. & Debt Prem.												
32			<u>\$ 3,529,452,246</u>	<u>\$ 4,321,436,711</u>	<u>\$ 4,321,623,433</u>	<u>\$ 4,321,800,461</u>	<u>\$ 4,321,977,317</u>	<u>\$ 4,322,154,174</u>	<u>\$ 4,322,331,031</u>	<u>\$ 4,522,507,888</u>	<u>\$ 4,522,684,745</u>	<u>\$ 4,522,861,602</u>	<u>\$ 4,523,038,458</u>
33	Effective Avg Cost of Consol Debt												
34	Consolidated & Utility												
35	Other Long-Term Real Estate Lease		-	2,493,151	2,488,831	2,534,508	2,475,736	2,475,666	6,665,965	6,522,821	6,510,961	8,636,367	8,647,263
36	Total Long-Term Debt Including Capital Leases		<u>3,529,452,246</u>	<u>4,323,929,862</u>	<u>4,324,112,264</u>	<u>4,324,334,969</u>	<u>4,324,453,053</u>	<u>4,324,629,840</u>	<u>4,328,996,996</u>	<u>4,529,030,709</u>	<u>4,529,195,706</u>	<u>4,531,497,968</u>	<u>4,531,685,721</u>
	Note: includes current maturities												
	ck Fin Rptg Bal		\$ 3,529,452,246	\$ 4,323,929,862	\$ 4,324,112,264	\$ 4,324,334,969	\$ 4,324,453,053	\$ 4,324,629,840	\$ 4,328,996,996	\$ 4,529,030,709	\$ 4,529,195,706	\$ 4,531,497,968	\$ 4,531,685,721
	diff Fin Rptg vs calc		-	-	-	-	-	-	-	-	-	-	-

	Acct 2241	Acct 2241	Acct 2241	Acct 2241	Acct 2241	Acct 2241	Acct 2241	Acct 2241	Acct 2241	Acct 2241	Acct 2241	Acct 2241	Acct 2241
	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	5/31/2020	6/30/2020	7/31/2020		
Note:	Unamortized Debt Expense	30,354,868.24	37,831,223.23	37,660,376.96	37,496,696.30	37,333,186.91	37,169,677.52	37,006,168.13	36,842,658.74	36,679,149.35	36,515,639.96	36,352,130.57	

**In Sept 16 the Company implemented FASB ASU 2015.03.

Atmos Energy Corporation

Consolidated Long-Term Debt Outstanding w/ calculation of Effective Interest Rate
September 30, 2020

Atmos Energy Corp., Consolidated:

Line	Debt Series	Issued	September 30, 2020	September 30, 2020	September 30, 2020	September 30, 2020	September 30, 2020	September 30, 2020	September 30, 2020	September 30, 2020	September 30, 2020
	(a)	(b)	(aa)	(ab)	(ac)	(ad)	(ae)	(af)	(ag)	(ah)	
1	9.40% First Mortgage Bond J due May 2021/RET 2005	04/01/91				46,700		-	326,899		
2	6.75% Debentures Unsecured due July 2028	07/27/98		4,641	3,688		436,225			342,938	
3	5.125% Senior Note due Jan 2013	01/13/03			-	-	-	-		-	
4	10.43% First Mortgage Bond P due 2017 (eff 2012)	11/01/87				-	-	0			
5	9.75% First Mortgage Bond Q due Apr 2020/RET 2005	04/01/90				-	-	(0)			
6	9.32% First Mortgage Bond T due June 2021/RET 2005	06/01/91				30,229		241,831			
7	8.77% First Mortgage Bond U due May 2022/RET 2005	05/01/92				30,727		583,806			
8	6.67% MTN A1 due Dec 2025	12/15/95		648			40,505				
9	4.95% Sr Note due 10/15/2014	10/22/04					-				
10	5.95% Sr Note due 10/15/2034	10/22/04	(587)	6,266	3,378		1,058,930			567,467	(99,246)
11	4.3% Sr Note due 10/1/2048	10/2018		17,930	8,350		6,024,501			2,805,600	
12	Sr Note 5.50% Due 06/15/2041	6/10/2011	(55,775)	11,994	3,578		2,974,476			887,289	(13,832,232)
13	8.50% Sr Note due 3/15/2019	03/23/09	-	-	-	-	-	0		-	-
14	4.15% Sr Note due 1/15/2043	01/15/13	185,071	14,907	2,611	13,988	3,987,683	3,741,882		697,167	49,599,135
15	4.125% Sr Note due 10/15/2044 (500MM(2014) & 250MM(2017)	10/15/2014	75,668	23,538	(27,168)		6,790,789			(7,839,231)	21,868,048
16	3% Sr Note due 6/15/2027	06/2017	-	34,798	11,458		2,801,212			922,396	-
17	4.125% Sr Note due 3/15/49	03/2019	250,393	13,428	4,925		4,578,994			1,679,425	85,634,323
18	2.625% Sr Notes Due 2029	10/2019		20,722	1,500		2,238,000			162,000	
19	3.375% Sr Notes Due 2049	10/2019		14,637	1,028		5,093,797			357,667	
20	\$200MM 3YR. Term Loan (Established 4/09/20)	04/2020		6,875			125,583				
21	October 2020 - Swap Position	04/2020									4,426,059
22	October 2021 - Swap Position	04/2020									(23,912,500)
23	October 2022 - Swap Position	07/2020									(23,522,912)
24	October 2024 - Swap Position	07/2020									(25,619,877)
25	Subtotal – Utility Long-Term Debt		454,770	170,384	13,347	121,644	36,150,695	4,894,417		582,716	74,540,798
26											
27	Other Long-Term Debt										
28	Total Long-Term Debt										
29	Less Unamortized Debt Discount & Debt Premium		454,770	170,384	13,347	121,644	36,150,695	4,894,417		582,716	74,540,798
30	Less Unamortized Debt Expense										
31	Annualized Amortization of T-Lock Settlement, Debt Exp, Debt Disc. & Debt Prem.		ck	ck		ck	ck	ck		ck	ck
32			454,770	183,732		121,644	36,150,695	4,894,417		582,716	74,540,798
33	Effective Avg Cost of Consol Debt		0	-		-	-	-		-	-
34	Consolidated & Utility										
35	Other Long-Term Real Estate Lease										
36	Total Long-Term Debt Including Capital Leases										

Note: includes current maturities

ck Fin Rptg Bal
diff Fin Rptg vs calc

Diff -

Note: Unamortized Debt Expense

**In Sept 16 the Company implemented FASB ASU 201503.

Realized
Realized
Realized
Realized
Realized
Realized
Realized
Realized
Unrealized
Unrealized
Unrealized
Unrealized

	Ledger Bal 09/30/20	Per Amort Sch & Value Def Tax Bal	Per Amort Sch & Value Lock Bal	Amort Sch vs. G/L Diff
20102	(76,993.21)	22,252.98	(99,246.19)	0.00
20103	-	-	-	-
20104	-	-	-	-
20105	(10,730,769.23)	3,101,463.14	(13,832,232.38)	(0.00)
20107	38,478,017.13	(11,121,118.10)	49,599,135.24	-
20108	(8,323,035.79)	2,405,567.41	(10,728,603.19)	-
20109	25,287,829.90	(7,308,821.08)	32,596,650.98	(0.00)
20111	66,433,395.37	(19,200,927.98)	85,634,323.35	0.00
20112	3,433,648.05	(992,410.95)	4,426,059.00	-
20113	(18,550,838.92)	5,361,660.66	(23,912,499.58)	-
20114	(18,248,604.82)	5,274,307.37	(23,522,912.19)	-
20115	(19,875,388.19)	5,744,488.83	(25,619,877.02)	-
	57,827,260.29	(16,713,537.73)	74,540,798.02	(0.00)

Atmos Energy Corporation
Allowance for Funds Used During Construction
Budget 2021

		31	30	31	31	28	31	30	31	30	31	31	30			
		Budget 2021														
		October	November	December	January	February	March	April	May	June	July	August	September	Total	12-mo Avg	
47	Equity Rate in AFUDC by Jurisdiction	(c)														
59	Tennessee	7.93%	7.90%	7.90%	7.89%	6.82%	7.84%	7.87%	7.88%	7.86%	7.88%	7.92%	7.84%			
70																
71	AFUDC Rate by Jurisdiction	(d)														
83	Tennessee	093DIV	10.77%	10.86%	10.80%	10.82%	9.47%	10.69%	10.76%	10.79%	10.77%	10.56%	10.82%	10.73%		

{a} ST DEBT / CWIP * ST Debt Cost Rate

{b} (1 - ST DEBT / CWIP) * LT Debt % * LT Debt Cost

{c} Equity % * Equity Cost (of Jurisdiction)

{d} Debt rate in AFUDC + Equity Rate in AFUDC

Budget
Formulas
Updated for actuals
Updated for projections
Input numbers

[illegible]

Atmos Energy Corporation
Computation of AFUDC Rate
September 2021
Methodology

18 CFR Part 201, Gas Plant Instructions, Components of construction costs, item 17.

(17) "Allowance for funds used during construction" includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed without prior approval of the Commission allowances computed in accordance with the formula prescribed in paragraph (a) below, except when such other funds are used for exploration and development or leases acquired after October 7, 1969, no allowance on such other funds shall be included in these accounts. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.

(a) The formula and elements for the computation of the allowance for funds used during construction shall be:

$$A_i = s \left(\frac{S}{W} \right) + d \left(\frac{D}{D + P + C} \right) \left(1 - \frac{S}{W} \right)$$

$$A_e = \left[1 - \frac{S}{W} \right] \left[p \left(\frac{P}{D + P + C} \right) + c \left(\frac{C}{D + P + C} \right) \right]$$

A_i = Gross allowance for borrowed funds used during construction rate.

A_e = Allowance for other funds used during construction rate.

S = Average short-term debt.

s = Short-term debt interest rate.

D = Long-term debt.

d = Long-term debt interest rate.

P = Preferred stock.

p = Preferred stock cost rate.

C = Common equity.

c = Common equity cost rate.

W = Average balance in construction work in progress.

(b) The rates shall be determined annually. The balances for long-term debt [1], preferred stock and common equity [2] shall be the actual book balances as of the end of the prior year. The cost rates for long-term debt and preferred stock shall be the weighted average cost determined in the manner indicated in subpart D of part 154 of the Commission's Regulations Under the Natural Gas Act. The cost rate for common equity shall be the rate granted common equity in the last rate proceeding before the ratemaking body having primary rate jurisdiction [3]. If such cost rate is not available, the average rate actually earned during the preceding three years shall be used. The short-term debt balances [4] and related cost and the average balance for construction work in progress [5] shall be estimated for the current year with appropriate adjustments as actual data becomes available.

NOTE: When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation, or ready for service, shall be treated as "Gas Utility Plant" and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service, except as limited in item 17, above.

[1] Please see WP L - LTD.

[2] Please see Wp C.

[3] The most recent case in which an ROE Mid-Tex 2012.
The rate agreed to in this proceeding was 10.5%.

[4] Please see Wp S.

[5] Please see Wp W - CWIP.

The USOA appears to contemplate AFUDC booked to individual projects based upon the length of time the project is in progress. For example, a project remaining open for 85 days would receive 85 days of interest recorded monthly based upon the cost rate applicable for each month.

beg_afudc_base	comp_desc	co_short	subtotal_value_desc	afudc_type_id	input_afudc_ratio	description
1,343,070.96	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3343.SR 99 PH1B
838,622.70	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3342.FranklinRdStreetscap
92,512.71	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.Southern Springs 7-8
302,307.02	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3342.EddyLaneROW
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.093.3434.FOOTHILL.MALL.DR
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.093.3435.THORNWOOD.SINT
1,861,015.51	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3343.NolenPktRockyFk
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342. Avenue Downs Ph. 1
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	COM.3342.Carlsle Lane extens
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3434.MRVL West Purch
157,270.92	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	FAM.3343.Salem Landing Ph1
604,797.09	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3434.N Wright Ph1
113,513.21	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	Wilson Pike / Triune Valves
12,899.03	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3436.MEADOW.PH3
287,285.92	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3343.Compton rd farm tap
617.61	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	COM.3342.Franklin Christian E
(5,137.86)	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.Southhallapproach
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.Starnes Creek P 1
6,692.68	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.Canterbury 18-19-20
49,718.43	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.Copperridge Phase 5
253,000.96	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.GR.Rosebrooke
9,366.46	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	COM.3342.Belshire Com.
18,206.83	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3435.Oak Grove Repl.
15,435.41	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.The Cove Phase 2
72.03	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3343.The Preserve Sec2
181,909.30	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3343.TDOTThompsonLnEase
587,016.49	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3342.SINTColNorthStationR
1,309.61	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3338.Countrywood St Ext
638.28	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3436.VILLAS.AT.OLD.MILL.2
496.89	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3436.VILLAS.AT.MILL.2.2
3,170.23	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.Harv Ph11,12,14,15
85,220.47	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3344. Del Ray replacement
2,222.16	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3343.Murfreesboro Airport
1,225.10	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	COM.3342.Southhall
304.27	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3439.5TH.ST.AT.CEDAR
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	FAM.3342.Kings Chapel Sec10
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	FAM.3342.Kings Chapel Sec11
8,252.65	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3343.Compton road lowerin
671.71	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	FAM.3343.Davenport Sec 3.3
13,061.85	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3344.McGrew and Main repl
2,446.76	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	FAM.3343.Shelton Square 3-1
39.26	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	FAM.3343.Shelton Square 3-2
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.093.3435.ALEX.HALL.LN.REI
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.Daventry Phase 3
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3343.Warrior. Hwy 99
23,713.40	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3342.GMRelocationROW
6,370.50	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	3342.Cemetary Ave repl
39,120.87	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.093.3434.ALCOA.HWY.PH4.RE
120,026.53	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.093.3434.ALCOA.HWY.RELOC
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	WMR.Lynchburg M400
78.52	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	COM.3343.MarketplaceatSavPH1
18,681.64	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.093.3435.HWY.11E.RD.WIDEN
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3434.Old Niles Ferry Rpl
407.01	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3436.5TH.STREET
46,589.29	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3342.BucknerLnReloPh1
40,997.16	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3343.BradyvillePikeRepl
40,357.07	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3344.TDOTSR55MooreCty
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.Morgan Meadows
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	FAM.3342.Lochnridge PH4
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	050.3342.TomJHitchPh2
-	050 Mid-States Division	Mid-States Division	093 - Tennessee Division	332	1	RES.3342.Waters Edge Phase 6
7,185,594.64	-	-	-	20,252.00		
64,261.80						

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-20
Page 1 of 2

REQUEST:

With regard to the Return to (Tax) Provision entries made during the test period, provide the following:

- a. Identify the entries made by division that reconcile the Income Tax related recordings with the company's most recently filed tax return. Also, identify the period in which such entries were made. Confirm that these true-up entries relate to the tax period ending September 2020.
- b. Provide a comprehensive discussion of the impact of these adjustments on the operating results recorded during the test period.

RESPONSE:

- a. As noted in the Company's response to CPAD 1-03, "A separate journal entry and workpapers specific to the true-ups is not available. The true-ups calculations and journal entries are a component of the overall workpapers and journal entries to record the following year provision for income tax expense."

A true-up adjustment is recorded to the financial statements after the filing of federal and state tax returns. Under GAAP, this adjustment is currently made in September of the year following the year when the income tax expense accrual (Provision) is first recorded, after the income tax returns had been filed with federal and state tax authorities. For example, the true-up entries related to the tax period ending September 2020 will be recorded to the Company's financials in September 2021.

- b. The income tax expense in the TN 22-00010 ARM filing was calculated by applying the federal and Tennessee statutory income tax rates to the required return, as shown on Schedule 8/8R. This calculation reflects actual income tax expense for Atmos Energy Tennessee for the 12 month period ending September 30, 2021 based on the revenue requirement in the model. Income tax expense in this filing has been calculated for the operations included in the test period being reconciled and using statutory rates at which the Company will pay tax for Tennessee operations. This methodology has been consistent based on the ARM model as per the Stipulation and Settlement Agreement under Docket Nos. 14-00146 and 18-00112.

This results in the proper collection of income tax associated with the Tennessee operations and the required return. The methodology yields the amount of income tax that will be remitted by the Company either currently or in the future based upon the required return for the period associated with this filing. This required return from customers will be taxed by the federal and Tennessee governments and calculating the tax in this manner ensures the Company collects as part of rates its liability to the federal and Tennessee governments.

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For financial reporting purposes, the Company calculates and records income tax expenses for each legal entity under ASC 740 within GAAP rule for each fiscal year. The Company's legal entity including the operations of Atmos Energy Tennessee, along with all other regulated operations, is Atmos Energy Corporation. The book income tax expense is based on the total income of Atmos Energy Corporation, which include Tennessee and all other jurisdictions.

Therefore, including per-books income tax for Atmos Energy Tennessee would not be reflective of actual Tennessee income tax expense. Instead, actual income tax expense is the amount resulting from applying the federal and Tennessee statutory income tax rates to the required return.

The Company records Return to (Tax) Provision to income tax expense resulting from the filing of the fiscal year ended 9/30/20 federal and state income tax returns in September 2021 books.

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-21
Page 1 of 1

REQUEST:

Refer to the Petition's Relied Upons, File <j. Income Statement.xlsx> and respond to the following:

- a. Identify the accounts/subaccounts and account titles of those accounts comprising the balance of "Other Operating Revenue" of \$1,094,874.
- b. Identify the accounts credited associated with the Expense recordings associated with "Franchise Taxes" and "Gross Receipts Taxes" and indicate whether such credits are incorporated into the test period revenue requirement deficiency.
- c. Describe the nature of the transactions giving rise to "Others Income" of \$612,607.

RESPONSE:

- a. Please see Attachment 1 for the Summary of "Other Operating Revenue" of \$1,094,874.
- b. Please see Attachment 2 for the accounts associated with "Franchise Taxes" and "Gross Receipts Taxes". The Corp/State Franchise Tax is the accrual for the 2021 Tennessee Franchise Tax that the Company pays as part of its income tax return in Tennessee. The Gross Receipts Taxes is for the Tennessee Gross Receipts Tax. These were included with Taxes Other Than Income Taxes in WP 5-1, which are a part of Cost of Service.
- c. Please see Attachment 3 for the Summary of Transactions for "Others Income" of \$612,607 which primarily consists of Account 419.1 "Allowance for other funds used during construction," which is a credit from Cost of Service in WP 1-2.

ATTACHMENTS:

CPAD_1-21_Att1 - Other Operating Revenues FY21.xlsx
CPAD_1-21_Att2 - Franchise Taxes & Gross Receipt Taxes FY21 - Div 093.xlsx
CPAD_1-21_Att3 - Others Income FY21 - Div 093.xlsx

Atmos Energy Corporation - Kentucky/Mid-States (Co050)
Division 093 - Mid-States-Tennessee
Other Operating Revenue
Fiscal Year 2021

Division	Division Description	Account	Account Description	Sub Account	Sub Account Description	OCT-20	NOV-20	DEC-20	JAN-21	FEB-21	MAR-21	APR-21	MAY-21	JUN-21	JUL-21	AUG-21	SEP-21	FY21
093	Mid-States-Tennessee	4880	Miscellaneous service revenues	31301	Misc Service Revenue	5,056	4,544	6,140	4,672	4,600	4,088	3,724	3,312	3,700	3,620	3,476	4,124	51,056
093	Mid-States-Tennessee	4950	Other gas revenues	31309	Other Gas Revenues	1	0	0	0	1	1	-	-	-	-	-	-	2
093	Mid-States-Tennessee	4960	Provision for Rate Refunds	31380	COS refund Residential	31,315	48,824	79,140	100,915	93,797	82,276	58,156	34,589	-	-	-	-	529,012
093	Mid-States-Tennessee	4960	Provision for Rate Refunds	31381	COS refund Commercial	14,184	23,579	42,561	66,720	66,970	53,629	36,327	19,787	-	-	-	-	323,757
093	Mid-States-Tennessee	4960	Provision for Rate Refunds	31382	COS refund Industrial	1,856	2,856	4,800	7,603	9,489	8,718	5,836	2,100	-	-	-	-	43,258
093	Mid-States-Tennessee	4960	Provision for Rate Refunds	31384	COS refund Public Auth	176	256	389	478	371	335	251	144	-	-	-	-	2,399
093	Mid-States-Tennessee	4960	Provision for Rate Refunds	31385	COS refund Transportation	11,200	16,018	22,656	23,328	24,621	22,372	13,416	11,778	-	-	-	-	145,389
						63,788	96,077	155,687	203,716	199,848	171,419	117,710	71,710	3,700	3,620	3,476	4,124	1,094,874

Atmos Energy Corporation - Kentucky/Mid-States (Co050)
Division 093 - Mid-States-Tennessee
Franchise Taxes & Gross Receipts Taxes
Fiscal Year 2021

Division	Division Description	Account	Account Description	Sub Account	Sub Account Description	OCT-20	NOV-20	DEC-20	JAN-21	FEB-21	MAR-21	APR-21	MAY-21	JUN-21	JUL-21	AUG-21	SEP-21	FY21
093	Mid-States-Tennessee	4081	Taxes other than income taxes, utility operating income	30105	Corp/State Franchise Tax	83,333	110,067	-	193,400	96,700	96,700	96,700	96,700	96,700	96,700	96,700	96,700	1,160,400
093	Mid-States-Tennessee	4081	Taxes other than income taxes, utility operating income	30107	City Franchise	167	167	167	167	167	167	167	167	167	167	167	167	2,000
093	Mid-States-Tennessee	4081	Taxes other than income taxes, utility operating income	30109	State Gross Receipts	48,392	78,824	118,988	132,807	112,409	93,461	58,961	38,944	36,415	37,314	35,896	38,585	830,996
						<u>131,892</u>	<u>189,057</u>	<u>119,155</u>	<u>326,373</u>	<u>209,276</u>	<u>190,328</u>	<u>155,828</u>	<u>135,811</u>	<u>133,281</u>	<u>134,181</u>	<u>132,763</u>	<u>135,452</u>	<u>1,993,396</u>

Atmos Energy Corporation - Kentucky/Mid-States (Co050)
Division 093 - Mid-States-Tennessee
Other Income
Fiscal Year 2021

Division	Division Description	Account	Account Description	Sub Account	Sub Account Description	Line Description	Journal Name	OCT-20	NOV-20	DEC-20	JAN-21	FEB-21	MAR-21	APR-21	MAY-21	JUN-21	JUL-21	AUG-21	SEP-21	FY21
093	Mid-States-Tennessee	4073	Regulatory Debits	41136	Billed from HQ - Below the line	Billing of MidStates HQ to Div 093	Billing of MidStates HQ to Div 093 ATC Reverses "Billing of MidStates HQ to Div 093 ATO"08-OCT-2021 15:23:34	(4,941)	(4,941)	(4,941)	(4,941)	(4,941)	(4,941)	(4,941)	(4,941)	(4,941)	(4,941)	(4,941)	(9,882)	(64,234)
093	Mid-States-Tennessee	4073	Regulatory Debits	41136	Billed from HQ - Below the line	Billing of MidStates HQ to Div 093	093 ATO"08-OCT-2021 15:23:34	-	-	-	-	-	-	-	-	-	-	-	4,941	4,941
093	Mid-States-Tennessee	4170	Revenues from nonutility operation	30526	Misc Other Revenue	Journal Import Createc	SAP-FIGL USD	975	1,000	1,025	1,025	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,075	12,450
093	Mid-States-Tennessee	4191	Allowance for other funds used during construction	00000	Default	Journal Import Createc	CR-Manual USD	67,946	51,180	73,586	64,988	62,001	49,573	46,528	53,548	65,082	57,740	18,106	38,207	648,484
093	Mid-States-Tennessee	4191	Allowance for other funds used during construction	41134	Billed from SS - Below the line	Billing of SS BTL for Div 093	Billing of SS BTL for Div 093 ATO Reverses "Billing of SS BTL for Div 093	-	-	147	295	256	296	297	312	326	-	540	1,606	4,075
093	Mid-States-Tennessee	4191	Allowance for other funds used during construction	41134	Billed from SS - Below the line	Billing of SS BTL for Div 093	ATO"08-OCT-2021 15:23:20	-	-	-	-	-	-	-	-	-	-	-	(803)	(803)
093	Mid-States-Tennessee	4210	Miscellaneous nonoperating income	41134	Billed from SS - Below the line	Billing of SS BTL for Div 093	Billing of SS BTL for Div 093 ATO Reverses "Billing of SS BTL for Div 093	567	-	-	-	-	-	2	-	-	-	-	2	570
093	Mid-States-Tennessee	4210	Miscellaneous nonoperating income	41134	Billed from SS - Below the line	Billing of SS BTL for Div 093	ATO"08-OCT-2021 15:23:20	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)
093	Mid-States-Tennessee	4211	Gain on Disposition of Property	30557	Gain or loss on disposition of leased property	LAM ADJ: FLT-GE-21284-093	842-050 Other USD	-	-	-	-	-	-	461	-	-	-	-	-	461
093	Mid-States-Tennessee	4211	Gain on Disposition of Property	30557	Gain or loss on disposition of leased property	LAM ADJ: FLT-GE-32326-093	842-050 Other USD	-	-	-	-	-	-	4,167	-	-	-	-	-	4,167
093	Mid-States-Tennessee	4211	Gain on Disposition of Property	30557	Gain or loss on disposition of leased property	LEASE AUTO RETIRE: FLT-GE-32328-093	842-050 Other USD	-	-	-	-	-	-	-	-	2,276	-	-	-	2,276
093	Mid-States-Tennessee	4211	Gain on Disposition of Property	41134	Billed from SS - Below the line	Billing of SS BTL for Div 093	Billing of SS BTL for Div 093 ATO	-	-	-	-	-	-	-	-	-	117	104	-	221
								64,546	47,239	69,817	61,366	58,366	45,977	47,562	49,969	63,794	53,966	14,859	35,145	612,607

Docket No. 22-00010
Atmos Energy Corporation, Tennessee Division
Consumer Advocate DR Set No. 1
Question No. 1-22
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REQUEST:

Refer to the Petition's Revenue Requirement Schedules, File <2022 ARM.xls>. The Company's Workpaper 10-IR computes test period Income Tax Expense of \$7,580,300. The Income Statement Schedule J reflects total Income Tax Expense of \$3,556,844. Reconcile this approximate \$4 million difference between the company's actual income tax expense and the imputed income tax expense for purposes of computing the test period earnings deficiency.

RESPONSE:

The primary difference between the two schedules is related to (\$2,967,239) in credits to income tax expense related to the amortization of excess deferred income taxes within the historical period income tax expense total of \$3,556,844. Also, please see the Company's response to CPAD 1-20 for more discussion on per books income tax expense compared to actual Tennessee income tax expense.

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REQUEST:

Refer to the Petition's Revenue Requirement Schedules, File <2022 ARM.xls>, Schedule 8. Provide the underlying calculations supporting the Company's book Income Tax Expense for the twelve month period ending September 30, 2021.

RESPONSE:

Please refer to the Company's response to CPAD 1-20. This calculation reflects actual income tax expense for Atmos Energy Tennessee for the 12 month period ending September 30, 2021 based on the revenue requirement in the model. Income tax expense in this filing has been calculated for the operations included in the test period being reconciled and using statutory rates at which the Company will pay tax for Tennessee operations. This methodology has been consistent based on the ARM model as per the Stipulation and Settlement Agreement under Docket Nos. 14-00146 and 18-00112.

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REQUEST:

Refer to the Petition, File <12) 22-XXXXX - 2022 Atmos Energy TN ARM Filing - Variance Report.xlsx>. Provide responses to the following questions regarding the O&M information presented in this file:

- a. Refer to Tab "093 O&M Acct", FERC account 9250 "A&G-Injuries & Damages". Specifically, regarding subaccount 5418 "Settlement" provide a narrative answer detailing why these MVA claims are not covered by the Company's automobile insurance.
- b. Refer to Tab "093 O&M Acct", FERC Account 9260 "A&G-Employee pensions and benefits". Provide documentation detailing the changes to OPEB as described in footnote F. If "changes" include modification of employee benefits, provide a comprehensive discussion of the nature of the benefit change along with its associated change in 2021 service costs.
- c. Refer to Tab "02 O&M Acct", FERC account 9260 "A&G-Employee pensions and benefits". Provide documentation detailing the changes to OPEB as described in footnote F. If "changes" include modification of employee benefits, provide a comprehensive discussion of the nature of the benefit change along with its associated change in 2021 service costs.
- d. Refer to Tab "91 O&M Acct". Reference the Company's statement in footnote B, which states "(t)he increase is due to higher labor charged to account 9030 during FY21 vs FY 18 & FY20". In the advocate' s review of the historic IS balances of division 91 account 8800 the increase was/is driven by Contract Labor expenses (sub 6111). Reconcile the company's footnote to the historic information.
- e. Provide a copy of any actuarial reports, or internal memos or reports that detail the change in Pension/OPEB costs.

RESPONSE:

- a. Auto claims covered by insurance would need to exceed our \$500,000 self-insured retention or \$500,000 deductible.
- b. Please see confidential Attachment 1 for the OPEB actuarial report. Page 4 of the report (PDF page 10) discusses the change in net periodic cost and funded position at an enterprise level from fiscal 2020 to fiscal 2021. Page 31 of the report (PDF page 37) is specific to the Kentucky/Mid-States Division.

Regarding changes to employee benefits, in fiscal 2021 the Company implemented a Pre-65 Retiree Hypertension program through Livongo to align with active benefits.

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- c. Please see confidential Attachment 1 for the OPEB actuarial report. Page 4 of the report (PDF page 10) discusses the change in net periodic cost and funded position at an enterprise level from fiscal 2020 to fiscal 2021. Page 23 of the report (PDF page 29) is specific to Shared Services.

Regarding changes to employee benefits, in fiscal 2021 the Company implemented a Pre-65 Retiree Hypertension program through Livongo to align with active benefits.

- d. The Company apologizes for the oversight in the initial footnote. The primary driver for the increase in 8800 is related to contract labor incurred as part of updating our maps and records. This effort largely started in the Company's fiscal year 2019 and was originally coded to FERC account 8700. A change was made during fiscal year 2020 to use FERC account 8800 resulting in the variances.
- e. Please see confidential Attachment 1 and confidential Attachment 2.

ATTACHMENTS:

CPAD_1-24_Att1 - OPEB Disclosure Report (CONFIDENTIAL).pdf
CPAD_1-24_Att2 - PAP Disclosure Report (CONFIDENTIAL).pdf

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REQUEST:

Refer to Petition's Secondary Relied Upens, File <SSU and KMD Trial Balance FY21.xlsx>. Specifically, refer to the charges to account 9250- "Injuries & Damages" shown on the Income Statement of Division 02 as presented in this document. Provide a narrative response detailing the drivers of the approximate 20% increase in the Company's subaccount 7121 "Insurance -Public Liability" since the year ended September 2020.

RESPONSE:

Additional premium costs are primarily related to our excess liability program. The excess liability market has seen a dramatic reduction in capacity along with significant rate increases around the globe. In addition, investment returns and uncertainty in the marketplace along with an increase in frequency and severity of losses contributed to premium increases.

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REQUEST:

Refer to the Petition's Secondary Relied Upons, File <SSU and KMD Trial Balance FY21.xlsx>. Specifically, refer to the charges to account 9260 -"A&G-Employee pensions and benefits" shown on the Income Statement of Division 02 as presented in this document. Provide responses to the following questions regarding this account:

- a. A narrative response detailing the Company's rationale of the inclusion of subaccount 1227 - "OPEB Regulated Asset O&M" along with any Regulatory Commission Order(s) supporting this treatment; and
- b. A narrative response detailing the drivers of increases in costs recorded in subaccount 1295 - "NSC-OPEB Benefits Variance." The Advocate notes this account has increased from an ending balance of \$257k in 2021 to an ending balance of \$18 million in 2022.

RESPONSE:

In September 2021, there was a one-time correction recorded to OPEB expense. This correction was recorded entirely to Shared Services in the month of September 2021 but impacted all business units. The entry to push down the correct amounts to the appropriate business units did not occur until Fiscal 2022. Please see below for responses to the specific subparts.

- a. This subaccount is used to record postretirement costs for a regulatory asset in our Texas and Colorado/Kansas business units. The reason Shared Services has a balance at September 2021 is due to the one-time correction described above. There were no amounts allocated to Tennessee for this amount in either Fiscal 2021 or Fiscal 2022 as the amounts related specifically to other business units.
- b. The large increase in this account is due to the one-time correction noted above. As described, this correction impacted all business units but was recorded entirely to Shared Services at September 2021 and then pushed down to the appropriate business units in Fiscal 2022. For Fiscal 2021, none of the costs associated with this one-time correction were charged to any specific business unit, including Tennessee. Thus, it does not impact our current rate filing. In Fiscal 2022, the portion of the correction related to Tennessee will be included.

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REQUEST:

Refer to the Petition's Secondary Relied Upons, File <SSU and KMD Trial Balance FY21.xlsx>. Specifically, refer to the charges to account 9302 - "Miscellaneous General Expenses", subaccount 7510 - "Association Dues" shown on the Income Statement of Division 93 as presented in this document. Provide a breakdown of showing the association name and amount paid for the year ended September 2021.

RESPONSE:

BLOUNT COUNTY CHAMBER OF COMMERCE	\$6,000
JOHNSON CITY CHAMBER OF COMMERCE	\$964
KINGSPORT CHAMBER	\$440
MARYVILLE ALCOA HOME BUILDERS ASSOCIATION	\$550
MIDDLE TENNESSEE INDUSTRIAL	\$8,598
TENNESSEE CHAMBER OF COMMERCE & INDUSTRY (TCCI)	\$10,250
TENNESSEE ECONOMIC DEVELOPMENT COUNCIL	\$2,500
TENNESSEE GAS ASSOCIATION	\$15,000
WILLIAMSON COUNTY CHAMBER OF COMMERCE	\$10,000
AMERICAN GAS ASSOCIATION (AGA)	\$47,815
Grand Total	\$102,117

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REQUEST:

Refer to the Petition's Secondary Relied Upons, File <SSU and KMD Trial Balance FY21.xlsx>. Specifically, refer to the charges to account 9230 - "A&G-Outside services employed", subaccount 6121- "Legal" shown on the Income Statement of Division 02 as presented in this document. Provide a narrative description of what these charges relate to along with a narrative detailing why the balance for this subaccount has fluctuated so dramatically over the last 3 years.

RESPONSE:

This subaccount is for Shared Services Legal Expense. This subaccount may fluctuate year to year as legal matters are often non-predictable and/or non-recurring. Additionally, the COVID pandemic dramatically reduced litigation costs in FY 2020 as many courts largely shut down.

For the FY21 amount shown, \$1,896,836 was related to Winter Storm Uri Securitization and coded to Company 010 in Cost Center 1903, and therefore not allocated to Tennessee. However, the Company has also identified approximately \$19,038 in FY21 legal charges that need be removed as they are not related to general corporate matters involving Tennessee and this adjustment is shown on Schedule 4 in the Company's updated Revenue Requirement model.

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REQUEST:

Refer to the Petition's Relied Upons, File <u. Supplemental Executive Retirement Plan FY21. Xlsx.>. Specifically, refer to the values shown in cells RI 0 and R27 which represent the capitalized Supplemental Executive Retirement Plan ("SERP") expenses for Divisions 02 and 91. With respect to SERP costs please respond to the following:

- a. Confirm that the SERP costs reflected in this schedule are based upon GAAP and do not represent cash contributions.
- b. Confirm that the Company has not removed the capitalized SERP costs reflected in Schedule U. If this is not confirmed, please identify where such costs were removed from Rate Base
- c. Provide the rationale and support for the 81.65% capitalization rate applied to division 2 SERP costs.

RESPONSE:

- a. Confirm.
- b. Confirm. Although not included in Docket No. 21-00019 final adjustments, after reviewing the Docket No. 21-00019 settlement agreement, the Company believes the capitalized SERP portion should be removed going forward and has removed the capitalized SERP costs in MFR #38 and the refiled ARM model as Attachment 1 to the Company's response to CPAD 1-09.
- c. The SERP costs for Division 002 are charged to Cost Center 1908-ATM Dallas SEBP. This cost center uses a total company capitalization rate that is calculated based on total company labor and contract labor for the latest fiscal year.

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REQUEST:

Confirm that the Company's position on the inclusion of non-cash items in the cash working capital calculation continues to be represented by its discovery response and rebuttal testimony in TPUC Docket No. 21-00019.

RESPONSE:

The Company continues to believe that the utilization of the methodology agreed to in Docket Nos. 14-00146 and 18-00112 is appropriate and that there is no reason to change one component of an overall agreement that strikes the right balance between the customer and the Company. With regards to CWC discussed in CAPD testimony in Docket No. 21-00019, the payment of an asset precedes the receipt of services from the asset and the recording of the depreciation expense. The lag between the payment for the asset and the recording of the depreciation expense is recognized by the including of net plant in service in rate base. However, the inclusion of an asset in rate base does not suffice to properly account for the entire lag relating to the depreciation of the asset. The inclusion of the asset in rate base does not include the subsequent lag from the provision of service to the receipt of cash for that service. By including depreciation 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. Likewise with return on equity, 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 the 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.

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REQUEST:

For the Transactions listed below within File <m. O&M by FERC.xlsx> account Division 002. Provide the following:

- a. Confirm that a pro-rata portion of these costs were allocated to Division 093 and that such allocated costs are reflected in the historic base period.
- b. If (a) is confirmed, provide the underlying documentation supporting the recording of this journal entry.
- c. Provide an explanation supporting the inclusion of these costs in the Division 093 revenue requirement.

Periods:

- 1) August 2021
- 2) September 2021

Cost Center:

- 1) 1903
- 2) 1105

Subaccount:

- 1) 06121
- 2) 0611

Subaccount Description:

- 1) Legal
- 2) Contract Labor

Net Amount:

- 1) \$853,589.21
- 2) \$780,029.88

Effective Period Number:

- 1) 181890099
- 2) 262730156

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RESPONSE:

- a. It is confirmed that amounts from Shared Services Division 002 were allocated to Tennessee Division 093 for the historic base period. Please note that certain Shared Services cost centers do not allocate expense to Tennessee, such as Cost Center 1903.
- b. The allocation of Shared Services O&M expense is recorded using Account 9220. There is a credit to Shared Services Account 9220 and corresponding debits to the Business Unit Account 9220 to transfer the expense from Shared Services to the appropriate business unit. This is a systematic journal entry performed at the end of each month. The trial balance subaccounts that capture this information for Tennessee are shown below:

9220-41131 - These are amounts allocated to Tennessee from SSU Div 012.

9220-41132 - These are amounts allocated to Tennessee from SSU Div 002.

9220-09341 - These are amounts allocated to Tennessee from KMD Div 091.

- c. Amounts from Cost Center 1903 do not allocate to Tennessee as described in the response to subpart (a). Thus, none of the \$853,589.21 referenced in this question got allocated to Tennessee as it was recorded in Cost Center 1903.

The \$780,029.88 recorded to Cost Center 1105 relates to both external and internal audit fees. The majority of this expense (\$613,750) are fees for required quarterly financial statement reviews and audits performed by our external auditor EY. The remaining amount is primarily related to our internal auditor KPMG for SOX and other compliance. These audits support the entire company and its financial reporting compliance requirements.

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REQUEST:

Refer to the underlying support for Division 002 and provide an explanation of the scope of services provided by the following cost centers and why such costs are appropriately allocated to Atmos' Tennessee division:

- a. ATM Dal Pipeline Safety (confirm that this is a company-wide cost center and not limited to Texas operations-if confirmed no further response required);
- b. ATM Transmission Gas Control Ops;
- c. ATM Transmission Operational Technology; and
- d. ATM New Orleans-Gas Supply.

RESPONSE:

- a. Confirm.
- b. The cost center ATM-Transmission Gas Control Ops is specific to our Texas operations and does not allocate costs to Tennessee.
- c. The cost center ATM-Transmission Operational Technology is specific to our Texas operations and does not allocate costs to Tennessee.
- d. The cost center ATM-New Orleans Gas Supply and Services allocates costs to the utility operations of Atmos Energy Corporation, including the state of Tennessee. The employees that work in this cost center support the gas supply operations of the company's entire utility operations, including Tennessee. The reason for "New Orleans" in the cost center description is because that is where the employee's offices are located.