RAILROAD COMMISSION OF TEXAS

HEARINGS DIVISION

GUD NO. 10506, *consolidated*
First Amended Proposal for Decision

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY (TGS), A DIVISION OF ONE GAS, INC., TO INCREASE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE EL PASO SERVICE AREA (EPSA), PERMIAN SERVICE AREA (PSA), AND DELL CITY SERVICE AREA (DCSA)

***PARTIES AND APPEARANCES**:*

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***PROCEDURAL HISTORY*:**

Statement of Intent Filed:	March 30, 2016
Rates Suspended:	April 12, 2016
Rate Case Expenses Severed Into GUD No. 10521:	May 27, 2016
Heard By:	John Dodson, Administrative Law Judge Rose Ruiz, Technical Examiner James Currier, Technical Examiner
Hearing on the Merits:	July 19-21, 2016
Consolidation of GUD No. 10536, Petition for Review:	July 22, 2016
Consolidation of GUD No. 10539, Petition for Review:	August 16, 2016
Record Closed:	August 31, 2016
PFD Issued:	August 31, 2016
Exceptions to PFD:	September 9, 2016
Record Re-Opened & Closed:	September 16, 2016
First Amended PFD Issued:	September 16, 2016
Statutory Deadline:	October 11, 2016

STATEMENT OF THE CASE

On March 30, 2016, Texas Gas Service Company ("TGS") filed with the Railroad Commission a Statement of Intent to increase gas utility rates within the unincorporated areas of three service areas: the El Paso Service Area ("EPSA"); the Permian Service Area ("PSA"); and the Dell City Service Area ("DCSA"). Along with rate increases, TGS also seeks to consolidate these three service areas into a single West Texas Service Area ("WTSA").

The Commission has both original and appellate jurisdiction in this docket. Original jurisdiction applies to the environs of the EPSA, PSA, and DCSA. Appellate jurisdiction applies to the following cities, which denied rate increases at the municipal level: Anthony, Clint, Dell City, El Paso, Horizon City, San Elizario, Socorro, and Vinton.

There are three intervening parties: Staff of the Railroad Commission ("Staff"); City of El Paso ("CEP"); and Coalition of Cities ("Coalition"), which is comprised of Clint, Horizon City, and San Elizario.

TGS requests: consolidation of service areas; a revenue requirement for the new WTSA totaling approximately $82 million—an increase of TGS's revenues in the combined EPSA, PSA, and DCSA by $12.76 million; approval of the prudence of capital investment in the WTSA made through December 31, 2015; approval of new depreciation rates; a finding that the transfer of TGS to ONE Gas is in the public interest; and recovery of rate case expenses.

There are relatively few contested issues. Among the most contested issues are:

- *Consolidation of service areas*. Staff supports consolidation. CEP and Coalition oppose;
- *Cost of equity*. TGS proposes 10 percent. Staff recommends 9.25 percent. CEP and Coalition recommend 9 percent;
- *Depreciation*. Staff supports TGS's proposed rates. CEP and Coalition oppose;
- *Incentive compensation*. TGS proposes 100 percent recovery of both short-term incentive ("STI") and long-term incentive ("LTI") compensation through rates. Staff does not oppose this. CEP and Coalition recommend partial STI and no LTI recovery;
- *Residential customer charge*. TGS proposes a $22 customer charge. Staff recommends a range of $12-14. CEP and Coalition recommend a lower, proportional charge; and
- *Tapping fees*. Staff argues that TGS's tapping fee provision may be discriminatory. TGS, CEP, and Coalition disagree with Staff and recommend keeping tapping fees.

SUMMARY OF AMENDED RECOMMENDATIONS

- Overall revenue requirement of $78,171,546—an increase of $8,803,936;
- Consolidation of the EPSA, PSA, and DCSA into a single service area;
- Cost of equity set at 9.5 percent;
- Depreciation rates consistent with TGS's proposed rates, with certain adjustments;
- Incentive compensation recovery of $817,095 for STI and $110,720 for LTI;
- Residential customer charge of $15.70; and
- Tapping fee provision is not discriminatory if language is modified.

SUMMARY OF CHANGES TO ORIGINAL PFD

The original PFD was issued on August 31, 2016. Having reviewed the parties' exceptions to the PFD, the Examiners determined it appropriate to issue this Amended PFD. The Examiners' ultimate recommendations and underlying analyses in the original PFD have not changed. This Amended PFD corrects typographical and calculation errors, and adds clarifying language in certain sections, where appropriate. Changes include:

- Typographical corrections;
- Changes to the summary of recommendations (p. iii);
- Additional language in section "III. PROCEDURAL BACKGROUND" (p. 4) that discusses the timely filing of certain exceptions to the PFD, and replies to the exceptions, as well as the re-opening of the evidentiary record for the limited purpose of admitting TGS Exhibit 30b;
- The addition of TGS Exhibit 30b to the list of TGS's exhibits in Attachment A;
- Clarification in Attachment A that there is no TGS Exhibit 31;
- Added language and a chart in section "VII. CONSOLIDATION OF SERVICE AREAS" (p. 10) to better convey CEP's argument regarding rate impact of service area consolidation on EPSA customers;
- Added language in section "VII. CONSOLIDATION OF SERVICE AREAS" (p. 10) to better convey Coalition's opposition to service area consolidation;
- Added language in section "VII. CONSOLIDATION OF SERVICE AREAS" (p. 13) to clarify that the *City of Dallas* case involved different factual circumstances;
- Added language and analysis in section "VIII. REVENUE REQUIREMENT" (pp. 20-21) relating to tapping fees—specifically, that modified tapping fee language proposed by TGS in its exceptions to the PFD would not be discriminatory to WTSA customers, and that the Examiners recommend approval of this language;
- Added language in section "VIII. REVENUE REQUIREMENT" (p. 29) further clarifying the Examiners' findings and recommendation with respect to return on equity;
- Correction in section "VIII. REVENUE REQUIREMENT" (pp. 50-51) to fix an arithmetical error relating to short-term incentive compensation. The correct recommended recovery amount is $817,095. This change affects other components of the revenue requirement and reduces the recommended revenue requirement by $79,133—from $78,250,679 to $78,171,546. This change also affects the volumetric rate for the residential class, decreasing this rate from $0.12307 to $0.12237. All major components that are changed are highlighted green on the attached schedules in Attachment D;
- Correction to the incentive compensation table in section "VIII. REVENUE REQUIREMENT" (p. 46) to show that the Commission allowed partial recovery of incentive compensation in GUD Nos. 9869 and 9762;

- Correction related to rate design in section "VIII. REVENUE REQUIREMENT" (p. 59) to correct the residential revenue-to-cost ratio to reflect the Examiners' revenue requirement recommendation as follows: 0.7873 to 0.9191;
- Correction related to rate design in section "VIII. REVENUE REQUIREMENT" (p. 61) to properly attribute the American Gas Association statistical reference to CEP and not TGS;
- Revision to the IRA base rate revenue allocation table in section "XI. PRUDENCY REVIEW AND INTERIM RATE ADJUSTMENTS" (p. 65) to reflect the base rate revenue allocation amounts to each customer class. This replaces the table in the original PFD that reflects the cost of service allocation amounts to each customer class; and
- The addition of section "XIII. CHANGES TO ORIGINAL PFD" (pp. 67-69) that discusses why the Examiners issued an Amended PFD and itemizes the notable amendments.

Notable changes to the schedules and relevant cells are highlighted in green in Attachment D. Schedule changes include:

- Correction to the customer bill impacts tab, per CEP's request. To do so, the Examiners had to correct the current and recommended rates tab;
- Correction to the short-term incentive compensation matrix to reflect the proper reduction amounts noted above, and a corresponding reduction of the volumetric rate from $0.12307 to $0.12237;
- Revision to the values on Excel line 43 of the "Class Revenue Allocation" tab to reflect the Examiners' recommended COS Revenue Increase to each customer class; and
- Other formulaic, flow-through changes resulting from the short-term incentive compensation reduction.

The Amended Proposed Final Order reflects these changes, where appropriate.

Since this Amended PFD and Amended Proposed Final Order are being formally served on all parties, the Commission does not need to separately note and specify in its Final Order any adopted amendments contained herein.

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FIRST AMENDED PROPOSAL FOR DECISION

I. INTRODUCTION

On March 30, 2016, Texas Gas Service Company ("TGS"), a division of ONE Gas, Inc. ("ONE Gas"), filed with the Railroad Commission of Texas ("Commission") a Statement of Intent to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area, Permian Service Area, and Dell City Service Area ("SOI"). The El Paso Service Area ("EPSA") is comprised of the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro, and Vinton, Texas, and their associated environs, including Fabens, Texas.[1] The Permian Service Area ("PSA") is comprised of the incorporated areas of Andrews, Barstow, Crane, McCamey, Monahans, Pecos, Pyote, Thorntonville, Wickett, and Wink, Texas, and their associated environs.[2] The Dell City Service Area ("DCSA") is comprised of the incorporated areas of Dell City, and its associated environs.[3] Along with rate increases, TGS also seeks to consolidate these three service areas into a new, combined service area known as the West Texas Service Area ("WTSA"). The deadline for Commission action is October 11, 2016.

TGS filed its SOI pursuant to Subtitle A (Gas Utility Regulatory Act) ("GURA") of the Texas Utilities Code, Chapter 104 (Rates and Services), Subchapter C (Rate Changes Proposed by Utility). In its SOI, TGS requests: consolidation of service areas; a revenue requirement for the new WTSA totaling approximately $82 million—an increase of TGS's revenues in the combined EPSA, PSA, and DCSA by $12.76 million; approval of the prudence of capital investment in the WTSA made through December 31, 2015; approval of new depreciation rates; a finding that the transfer of TGS from ONEOK, Inc. ("ONEOK") to ONE Gas is in the public interest; and recovery of rate case expenses.

The Commission has both original and appellate jurisdiction in this docket. Original jurisdiction applies to the environs of the EPSA, PSA, and DCSA. Appellate jurisdiction applies to the following cities, which denied rate increases at the municipal level: Anthony, Clint, Dell City, El Paso, Horizon City, San Elizario, Socorro, and Vinton. Customer counts by class are shown below.

Table 1 – Customer Count by Class/Area

Location	Residential	Commercial and Commercial A/C	Public Authority, Public and A/C	Municipal Water Pumping	Industrial	Electrical Cogen.	Stand By	Standard Transport.	Grand Total
El Paso Inc.	210,896	12,263	875	18	36	0	0	34	224,122
El Paso Environs	12,353	599	96	2	3	0	0	3	18,056
Dell City Inc.	142	20	7	0	0	0	0	0	169
Dell City Environs	40	4	0	0	0	0	0	0	44
Permian Inc.	9,232	834	205	0	0	0	0	0	10,271
Permian Environs:									
Andrews	134	33	4	0	1	0	0	0	172
Crane	85	14	1	0	0	0	0	0	100
McCamey	63	4	2	0	0	0	0	0	69
Pecos-Monahans	190	51	21	0	1	0	0	0	263
TOTAL	238,135	13,822	1,211	20	41	0	0	37	253,266

[1] TGS Ex. 1 (SOI) at 4.
[2] *Id*. at 4-5.
[3] *Id*. at 5.

II. PARTIES

The parties in this proceeding are Applicant TGS and three intervenors: Staff of the Railroad Commission ("Staff"); City of El Paso ("CEP"); and Coalition of Cities, whose members include the EPSA cities of Clint, Horizon City, and San Elizario ("Coalition").

TGS (Utility)

TGS is a division of ONE Gas and is a "gas utility" under GURA Section 101.003 (Definitions).[4] TGS filed its SOI with the Commission on March 30, 2016, and contemporaneously filed a Statement of Intent to Increase Rates with each municipality retaining original jurisdiction in the EPSA and DCSA.[5]

Intervenors: Staff, CEP, and Coalition

On March 30, 2016, Staff moved to intervene in this docket "to assert its interest in seeing that the rules and regulations of the Commission together with the appropriate statutes have been followed."[6] CEP and Coalition moved to intervene in this docket on April 6, 2016, and May 17, 2016, respectively.[7]

III. PROCEDURAL BACKGROUND

On March 30, 2016, TGS filed with the Commission its SOI to increase gas utility rates within the unincorporated areas of the EPSA, PSA, and DCSA, and to consolidate these three service areas into a new, combined WTSA. Subsequently, Staff, CEP, and Coalition intervened. On April 12, 2016, the Commission suspended TGS's proposed rate change for a period of 150 days—from May 4, 2016, to October 1, 2016—pursuant to GURA Section 104.107 (Rate Suspension; Deadline).[8] Subsequently, TGS voluntarily extended this deadline from October 1, 2016, to October 11, 2016.[9] Prehearing conferences were held on April 12, 2016, and May 5, 2016, to consider various procedural matters and technical issues. On May 11, 2016, TGS filed certain errata to its original SOI (the "Errata Filing"). On May 19, 2016, CEP and Coalition

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[4] 16 Tex. Admin. Code § 101.003(7) (Definitions) (defining "gas utility" as "a person or river authority that owns or operates for compensation in this state equipment or facilities to transmit or distribute combustible hydrocarbon natural gas or synthetic natural gas for sale or resale in a manner not subject to the jurisdiction of the Federal Energy Regulatory Commission under the Natural Gas Act (15 U.S.C. Section 717 et seq.). The term includes a lessee, trustee, or receiver of a gas utility.").

[5] TGS Ex. 1 (SOI) at 1.

[6] *See* Staff's Motion to Intervene, filed March 30, 2016, at 1; *see also* Examiners' Letter No. 2 (Motion to Intervene by Staff of the Railroad Commission), issued March 30, 2016.

[7] *See* Examiners' Letter No. 4 (Motion to Intervene by City of El Paso), issued April 6, 2016, *and* Examiners' Letter No. 10 (Motion to Intervene by Coalition of Cities), issued May 17, 2016.

[8] *See* Tex. Util. Code § 104.107(a)(2) (Rate Suspension; Deadline) ("Pending the hearing and a decision…the railroad commission may suspend the operation of the schedule for not longer than 150 days after the date the schedule would otherwise be effective.").

[9] *See* Joint Proposed Procedural Schedule, filed by TGS on April 14, 2016, at 2 ("In addition, consistent with the schedule above, the Company has agreed to an extension of the statutory deadline by 10 days or until October 11, 2016.").

were aligned pursuant to Commission Rule § 1.86 (Alignment of Municipal Intervenors for Purposes of Discovery).[10]

On May 25, 2016, TGS provided public notice of its SOI to each TGS customer within the EPSA, PSA, and DCSA by direct mail ("Public Notice").[11] From May 25-31, 2016, the Commission received four comment letters from the public, each voicing opposition to TGS's proposed rate amounts as contained in the Public Notice. On June 8, 2016, the ALJ forwarded to each a "Complaint and Statement of Intent to Participate Form" in accordance with Commission Rule § 7.240 (Statement of Intent to Participate).[12] No form was returned to the Commission, timely or otherwise.

On May 27, 2016, the rate case expenses portion of GUD No. 10506 was severed into a separate docket, GUD No. 10521. On June 10, 2016, the ALJ issued a Notice of Hearing, which set the hearing on the merits in GUD No. 10506 for July 19-21, 2016 ("Notice of Hearing"). On June 14, 2016, the Commission published the Notice of Hearing in *Gas Utilities Information Bulletin No. 1037*.[13] By June 22, 2016, the ALJ provided the Notice of Hearing to the governing body of each affected municipality and county.[14]

On July 8, 2016, the ALJ issued a ruling precluding litigation of the issue of whether the transfer of TGS to from ONEOK to ONE Gas is in the public interest because the Commission already made this determination in a previous docket, GUD No. 10488.[15] On July 18, 2016, the ALJ issued rulings that granted three TGS motions to seal certain highly-sensitive and confidential material.[16] The hearing on the merits was held on July 19-21, 2016 (the "Hearing"). All parties—TGS, Staff, CEP, and Coalition—participated in the Hearing. Lists of the parties' exhibits admitted into the evidentiary record are attached to this PFD as Attachment A. Previous Commission Final Orders and PFDs referenced by the parties' witnesses in their testimonies also are included in this docket's evidentiary record.[17]

From July 7-26, 2016, each of the Cities of Anthony, Clint, Dell City, El Paso, Horizon City, San Elizario, Socorro, and Vinton (the "Appellate Cities") timely took municipal action

[10] *See* Examiners' Letter No. 11 (Alignment of Municipal Intervenors), issued May 19, 2016; *see also* 16 Tex. Admin. Code § 1.86 (Alignment of Municipal Intervenors for Purposes of Discovery) ("Municipal parties, whether participating as a single municipality or a coalition of municipalities, are presumed to share a common interest in a proceeding such that alignment of municipal parties as a single party for purposes of discovery is appropriate. The presiding officer shall order alignment of municipal intervenors at the earliest reasonable opportunity so as to avoid unnecessary duplication of effort and to allow aligned parties an adequate opportunity to coordinate discovery efforts in an efficient manner.").

[11] *See* TGS Ex. 4, Affidavit of Notice, sworn to by Janet L. Buchanan on June 1, 2016, and filed with the Commission on June 3, 2016 ("Buchanan Aff."), ¶¶ 3-4.

[12] Letter from the ALJ to all Complainants, dated June 8, 2016 (attaching Complaint and Statement of Intent to Participate Form).

[13] *See Gas Utilities Information Bulletin No. 1037*, published by the Railroad Commission of Texas Oversight and Safety Division on June 14, 2016 ("Bulletin").

[14] *See* letters from ALJ to County Judges for the Counties of Andrews, Crane, El Paso, Reeves, Upton, Ward, and Winkler, dated June 14, 2016 (attaching the Notice of Hearing), and letter from ALJ to County Judge for Hudspeth County, dated June 22, 2016 (attaching the Notice of Hearing).

[15] *See* Examiners' Letter No. 18 (Ruling on TGS's Motion to Preclude), issued July 8, 2016.

[16] *See* Examiners' Letter No. 20 (Rulings on Motions to Seal the Administrative Record), issued July 18, 2016 (granting Motion to Seal the Administrative Record motions filed by TGS on May 11, July 1, and July 15, 2016).

[17] Hearing Tr. at 56-57 (July 21, 2016) (ALJ taking official notice of Commission Final Orders and PFDs referenced by all parties' witnesses in their testimonies).

denying TGS's rate request. On July 15, 2016, TGS timely filed with the Commission a petition for review from El Paso's denial, which was docketed as GUD No. 10536.[18] On July 22, 2016, the rate case expense portion of GUD No. 10536 was consolidated into GUD No. 10521, and the remainder of GUD No. 10536 was consolidated into GUD No. 10506.[19] On August 5, 2016, TGS timely filed with the Commission a petition for review of the denials by the Cities of Anthony, Clint, Dell City, Horizon City, San Elizario, Socorro, and Vinton, which was docketed as GUD No. 10539.[20] On August 16, 2016, the rate case expense portion of GUD No. 10539 was consolidated into GUD No. 10521, and the remainder of GUD No. 10539 was consolidated into GUD No. 10506.[21] On August 16, 2016, the ALJ issued rulings that granted two TGS motions to seal certain highly-sensitive and confidential materials filed in conjunction with TGS's July 15, 2016, and August 5, 2016 petitions for review.[22]

On August 31, 2016, the evidentiary record closed and the original PFD was issued.[23]

On September 9, 2016, TGS, CEP, and Coalition each timely filed exceptions to the PFD. On September 16, 2016, the evidentiary record was re-opened briefly for the limited purpose of admitting into evidence TGS Exhibit 30b, which is a copy of the signed minutes from the City of Socorro's July 7, 2016 council meeting noting the denial of TGS's rate request. The evidentiary record was then again closed.

IV. JURISDICTION, BURDEN OF PROOF, AND NOTICE

Jurisdiction

The Commission has jurisdiction over TGS, which is a gas utility as defined in GURA Section 101.003(7). Pursuant to GURA Section 102.001(a), the Commission has exclusive original jurisdiction to set the rates TGS requests for customers in the unincorporated areas of the current EPSA, PSA, and DCSA. Pursuant to GURA Section 102.001(b), the Commission has exclusive appellate jurisdiction to review the municipal actions of the Cities of Anthony, Clint, Dell City, El Paso, Horizon City, San Elizario, Socorro, and Vinton. The Commission has jurisdiction over all matters at issue in this proceeding pursuant to GURA Chapters 102 (Jurisdiction and Powers of Railroad Commission and Other Regulatory Authorities), 103 (Jurisdiction and Powers of Municipality), and/or 104 (Rates and Services). The statutes and rules involved in this proceeding include, but are not limited to, those contained in GURA Chapters 102, 103, and 104, and Title 16 (Economic Regulation), Part 1 (Railroad Commission of Texas), Chapters 1 (Practice and Procedure) and 7 (Gas Services Division) of the Texas Administrative Code.

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[18] *See* TGS Exs. 3 (GUD 10536 Petition for Review) and 3a (related confidential electronic files).
[19] *See* Examiners' Letter No. 21 (Consolidation of GUD No. 10536), issued July 22, 2016.
[20] *See* TGS Exs. 30 (GUD 10539 Petition for Review) and 30a (related confidential electronic files).
[21] *See* Examiners' Letter No. 25 (Consolidation of GUD No. 10539), issued August 16, 2016.
[22] *See* Examiners' Letter No. 26 (Rulings on Appellate Motions to Seal the Administrative Record), issued August 16, 2016.
[23] *See* Examiners' Letter No. 31 (Close of Evidentiary Record), issued Aug. 31, 2016.

Burden of Proof

As the party proposing gas utility rate changes, TGS has the burden of proving that the rate changes are just and reasonable.[24]

Notice

Proper notice has been issued in this proceeding in accordance with applicable statutes and rules. On May 25, 2016, TGS provided public notice of its SOI to each TGS customer within the EPSA, PSA, and DCSA by direct mail.[25] On June 10, 2016, the ALJ issued the Notice of Hearing, which complied with Chapter 2001 (Administrative Procedure) of the Texas Government Code, Part 1 (Railroad Commission of Texas) of Title 16 (Economic Regulation) of the Texas Administrative Code, and other applicable authority. On June 14, 2016, the Commission published the Notice of Hearing in *Gas Utilities Information Bulletin No. 1037* in compliance with Commission Rule § 7.235 (Publication and Service of Notice).[26] Pursuant to GURA Section 104.105 (Determination of Propriety of Rate Change; Hearing), the ALJ provided a copy of the Notice of Hearing to the governing body of each affected municipality and county.[27]

Proper notice has been issued in this proceeding in accordance with all applicable statutory and regulatory requirements.

V. COMPLIANCE WITH COMMISSION RULES; BOOKS AND RECORDS

TGS presented evidence that it maintains its books and records in accordance with Commission requirements.[28] Stacey L. McTaggart, Rates and Regulatory Director for TGS, testified that TGS maintains its books and records in accordance with Commission Rule § 7.310 (System of Accounts), which requires each gas utility to "utilize the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA) prescribed for Natural Gas Companies subject to the Provisions of the Natural Gas Act (as amended from time to time) (FERC USAO) for all operating and reporting purposes."[29] Ms. McTaggart further testified that the information contained within TGS's books and records, as well as the summaries and excerpts therefrom, qualify for the presumption set forth in Commission Rule § 7.503 (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities).[30] Ms.

[24] Tex. Util. Code § 104.008 (Burden of Proof).

[25] *See* TGS Ex. 4 (Buchannan Aff.) ¶¶ 3-4; *see also* Tex. Util. Code § 104.103 (Notice of Intent to Increase Rates) (containing notice requirements) *and* 16 Tex. Admin. Code §§ 7.220 (Environs Rates), 7.230 (Contents of Notice), and 7.235 (Publication and Service of Notice) (containing notice requirements).

[26] 16 Tex. Admin. Code § 7.235(a)(1)(A) (Publication and Service of Notice) ("The Commission shall publish the notice of hearing in the next Bulletin published after the date of issuance of the notice of hearing."); Bulletin, pp. 3-6 (containing the GUD No. 10506 Notice of Hearing).

[27] Tex. Util. Code § 104.105(c) (Determination of Propriety of Rate Change; Hearing) ("The regulatory authority shall give reasonable notice of the hearing, including notice to the governing body of each affected municipality and county.").

[28] *See* TGS Ex. 7, Direct Testimony of Stacey L. McTaggart on Behalf of Texas Gas Service Company ("McTaggart Test."), at 3-8.

[29] *Id*. at 3; *see* 16 Tex. Admin. Code § 7.310(a) (System of Accounts).

[30] TGS Ex. 7 (McTaggart Test.) at 5; *see* 16 Tex. Admin. Code § 7.503(a) (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities).

McTaggart testified that TGS is in compliance with Commission Rule § 7.501 (Certain Matters to be Submitted in Rate Hearings), which requires the separate presentation in a rate proceeding of evidence related to certain types of financial transactions, and in some cases, exclusion of these costs from rates,[31] and with Commission Rule § 7.5414 (Advertising, Contributions, and Donations), which states that actual expenditures for advertising will be allowed as a cost-of-service item for ratemaking purposes, provided that the total sum of such expenditures shall not exceed one-half of one (1) percent of the gross receipts of the utility for utility services rendered to the public.[32]

Ms. McTaggart further testified that TGS did not incur any affiliate expenses during the test year that might trigger application of GURA Section 104.055 (Net Income; Allowable Expenses).[33]

No party disputes that TGS maintains its books and records in accordance with Commission requirements.

Considering the evidence, the Examiners find that TGS has established that it complied with these Commission rules. Accordingly, TGS is entitled to the presumption set forth in Commission Rule § 7.503 (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities) that the unchallenged amounts shown in its books and records are presumed to have been reasonably and necessarily incurred.[34]

VI. OVERVIEW OF TGS'S FILING AND PARTY POSITIONS

TGS requests: consolidation of service areas; a revenue requirement for the new WTSA totaling approximately $82 million—an increase of TGS's revenues in the combined EPSA, PSA, and DCSA by $12.76 million; approval of the prudence of capital investment in the WTSA made through December 31, 2015; approval of new depreciation rates; a finding that the transfer of TGS to ONE Gas is in the public interest; and recovery of rate case expenses. On May 3, 2016, after the SOI in this docket was filed, the Commission determined in a separate docket that the transfer of TGS to ONE Gas is in the public interest.[35] Accordingly, this issue was precluded

[31] TGS Ex. 7 (McTaggart Test.) at 5-7; *see* 16 Tex. Admin. Code § 7.501 (Certain Matters to be Submitted in Rate Hearings).

[32] TGS Ex. 7 (McTaggart Test.) at 7-8; *see* 16 Tex. Admin. Code § 7.5414 (Advertising, Contributions, and Donations).

[33] TGS Ex. 7 (McTaggart Test.) at 8-9.

[34] *See* 16 Tex. Admin. Code § 7.503(a) (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities) ("In any proceeding before the Commission involving a gas utility that keeps its books and records in accordance with Commission rules, the amounts shown on its books and records as well as summaries and excerpts therefrom shall be considered prima facie evidence of the amount of investment or expense reflected when introduced into evidence, and such amounts shall be presumed to have been reasonably and necessarily incurred; provided, however, that if any evidence is introduced that an investment or expense item has been unreasonably incurred, then the presumption as to that specific investment or expense item shall no longer exist and the gas utility shall have the burden of introducing probative evidence that the challenged item has been reasonably and necessarily incurred.").

[35] *See* GUD No. 10488, *Statement of Intent of Texas Gas Service Company, A Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, Final Order, signed May 3, 2016, at Findings of Fact 47, 48, and Conclusion of Law 30.

from litigation.[36] Recovery of rate case expenses associated with this consolidated proceeding will be considered in a separate docket, GUD No. 10521.[37]

There are relatively few contested issues. Among the most contested issues are: consolidation of service areas, cost of equity, depreciation rate amounts, incentive compensation, rate design with respect to the residential customer charge, and whether TGS's "tapping fee" mechanism is discriminatory.

Summary of Staff's Positions

Staff and TGS are in agreement on several issues, including: service area consolidation, depreciation rate amounts, capital structure, cost of gas clause language, handling of pipeline integrity testing expenses, removal of duplicative sales tax, and various adjustments to TGS's rate schedules and tariffs. Also, Staff did not oppose TGS's proposed recovery through rates of incentive compensation.

Staff opposes TGS on cost of equity, recommending a 9.25 percent return on equity instead of TGS's proposed 10 percent. Staff opposes TGS on rate design, recommending a $12-$14 residential customer charge instead of TGS's proposed $22. Staff opposes TGS's use of a "tapping fee" mechanism for certain customers—a practice Staff argues may be discriminatory.

Summary of CEP's and Coalition's Positions

TGS and CEP are in agreement on some issues, including: removal of duplicative sales tax; and TGS's "tapping fee" mechanism not being discriminatory.

CEP opposes TGS with respect to: service area consolidation, depreciation rate amounts, incentive compensation, cost of equity, certain rate base issues, and revenue allocation and rate design. For incentive compensation, CEP recommends recovery through rates of 10 percent short-term and zero percent long-term, in contrast to TGS's proposed 100 percent recovery through rates for both. For cost of equity, CEP recommends a 9 percent return on equity instead of TGS's proposed 10 percent. For rate design, CEP recommends, among other things, a residential customer charge reflective of the percent base revenue increase, in contrast to TGS's proposed $22.

Coalition participated in the Hearing but did not submit pre-filed testimony or offer its own experts. Coalition represented that it is "aligned with [CEP]" and "adopts wholly and fully the evidence submitted, positions urged and arguments in support, presented by [CEP] in this proceeding."[38]

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[36] *See* Examiners' Letter No. 18 (Ruling on TGS's Motion to Preclude), issued July 8, 2016.

[37] *See* Examiners' Letter No. 12 (Rate Case Expense Docket), issued May 27, 2016 (severing the rate case expense portion of GUD No. 10506 into a separate docket, GUD No. 10521).

[38] Trial Brief of the Coalition of Cities Served by Texas Gas Service Company, filed July 18, 2016 ("Coalition Trial Br."), at 2.

VII. CONSOLIDATION OF SERVICE AREAS

Consolidation of service areas is a major point of disagreement between TGS and CEP/Coalition. TGS proposes to consolidate the EPSA, PSA, and DCSA into a single service area and to set rates based on the total cost to serve the new, consolidated WTSA. In support, TGS offers that service area consolidation is in the public interest because it: is supported by Texas law and Commission precedent, better reflects TGS's operational realities, and results in administrative and regulatory efficiencies. A map showing TGS's service areas is attached to this PFD as Attachment B. Staff supports consolidation of these service areas as being reasonable and supported by two recent Court of Appeals holdings and at least 13 prior Commission dockets.[39] CEP and Coalition both oppose.

TGS offers that service area consolidation is supported by Texas law and Commission precedent. According to TGS, the Commission has a long-established policy of approving consolidation and system-wide rates, and that doing so reflects the regulatory framework established in the Texas Utilities Code.[40] In particular, TGS highlights the Commission's actions in GUD Nos. 9400, 9488, and 10174. In GUD No. 9400, the Commission adopted system-wide rates for an area that included over 400 cities from Austin to Dallas—a decision ultimately upheld by the Third Court of Appeals.[41] In GUD No. 9488, the Commission adopted system-wide rates for a broad geographic area even though customers in some cities would experience rate decreases and customers in other cities would experience rate increases.[42] In GUD No. 10174, the Examiners precluded litigation of the issue of consolidation altogether, stating that the Commission has "a long-established policy allowing utilities within the State of Texas to seek system-wide rates."[43] Additionally, TGS notes numerous prior dockets where the Commission approved the use of system-wide rates: GUD Nos. 9670, 9762, 9869, 10170, and 10174 (Atmos Energy); and GUD Nos. 9791, 9902, and 10038 (CenterPoint Energy).[44]

TGS offers that service area consolidation better reflects TGS's operational realities. Caron Lawhorn, Senior Vice President, Commercial, for ONE Gas, testified that consolidating service areas provides for more efficient management of regulatory matters and rate-setting efficiencies, and aligns with the functional model by which ONE Gas operates and manages utility operations throughout ONE Gas.[45] Jim Jarrett, Vice President of Operations for TGS, testified that decision-making processes, operations, and management are now centralized in the WTSA, which means that service area boundaries are no longer indicative of TGS's actual

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[39] Closing Brief of the Staff of the Railroad Commission of Texas, filed Aug. 3, 2016 ("Staff Initial Br."), at 2 (citing *City of Dallas v. R.R. Comm'n of Tex.*, No. 03-06-00580-CV, 2008 WL 4823225, at *1 (Tex. App.—Austin, Nov. 6, 2008, no pet.) (mem. op.), and *Amarillo v. R.R. Comm'n of Tex.*, No. 08-14-00193-CV, 2016 WL 3020304, at *1 (Tex. App.—El Paso, May 25, 2016, no pet.)).

[40] Initial Brief of Texas Gas Service Company, A Division of ONE Gas, Inc., filed Aug. 3, 2016 ("TGS Initial Br."), at 4-6.

[41] GUD No. 9400, Final Order (May 25, 2004); *City of Dallas*, 2008 WL 4823225, at *4, 8-9 (noting that the City of Dallas opposed consolidation based, in part, on arguments that under consolidation Dallas would be subsidizing the utility's customers in other parts of the state).

[42] TGS Initial Br. at 5 (discussing GUD No. 9488, Final Order (Nov. 23, 2004)).

[43] *Id*. at 5 (quoting GUD No. 10174, Examiners' Letter No. 29).

[44] *Id*. at 5-6.

[45] TGS Ex. 5, Direct Testimony of Caron A. Lawhorn on Behalf of Texas Gas Service Company ("Lawhorn Test."), at 11-12.

operations.[46] According to TGS, the centralization of these activities has allowed TGS to make more efficient use of employees and to control costs by improving consistency in processes.[47] Mr. Jarrett testified that: supervisors in the EPSA have responsibility for activities such as leak survey across the entire WTSA; one supervisor retains responsibility for cathodic protection throughout the WTSA; and the engineering team in the EPSA has responsibility throughout the WTSA.[48] Mr. Jarrett further testified that operational leadership for the EPSA, PSA, and DCSA is located in El Paso, and the proximity of the EPSA, PSA, and DCSA "affords the opportunity for these service areas to share equipment and deploy resources in a manner that allows [TGS] to quickly respond to emergencies."[49] TGS maintains that these operational changes already have taken place, and that consolidation simply reflects the operating changes that already have occurred.[50]

TGS offers that service area consolidation results in administrative and regulatory efficiencies. Consolidation will allow TGS to prepare only one cost-of-service filing for future rate changes instead of three—something TGS maintains would result in uniformity and consistency in rate setting, and would be more economical and efficient for TGS, customers, and regulators.[51] According to TGS, it would maintain approximately 26 total tariffs for the consolidated WTSA, rather than the existing 125 tariffs in the EPSA, PSA, and DCSA, as separate service areas.[52]

Opposition by CEP and Coalition

Neither CEP nor Coalition submitted pre-filed testimony that directly challenged consolidation, though both opposed consolidation during the Hearing and in post-Hearing briefs.

CEP offers that the EPSA has been a distinct service area for more than 40 years and characterizes TGS's requested consolidation as punitive to EPSA ratepayers because it imposes a substantially greater increase on those customers while cutting rates for customers in the smaller PSA and DCSA.[53] CEP also states that rates under TGS's proposed consolidation would be "discriminatory" and "prejudicial" to EPSA customers.[54] CEP acknowledges that Commission policy has favored consolidation, but offers that consolidation needs to make sense and not discriminate against one group of customers.[55]

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[46] *See* TGS Ex. 6, Direct Testimony of Jim Jarrett on Behalf of Texas Gas Service Company ("Jarrett Test."), at 5-10.
[47] *Id*. at 7-10.
[48] *Id*.; Tr. at 91-92 (July 19, 2016) (Jarrett testifying).
[49] TGS Ex. 6 (Jarrett Test.) at 10.
[50] *Id*. at 11.
[51] *Id*. at 10-11.
[52] TGS Initial Br. at 6 (citing TGS Response to Examiner RFI 1-1 (July 29, 2016)).
[53] Trial Brief of the City of El Paso, filed July 18, 2016 ("CEP Trial Br."), at 2.
[54] *Id*.; see *also* Post Hearing Brief of the City of El Paso, filed Aug. 4, 2016 ("CEP Initial Br."), at 6 ("In the instant case the 'West Texas Service Area' is nothing new, it is a mere device to provide discrimination in rates.").
[55] CEP Trial Br. at 2.

In its exceptions to the PFD, CEP provided the below chart to highlight the rate impact of consolidation on EPSA customers.[56]

Service Area	Stand Alone Errata Requested Increase	Consolidated Requested Increase	Difference
EPSA	$12,296,801	$14,063,105	$1,766,801
PSA	$583,801	($1,538,777)	($2,122,578)
DCSA	$(14,205)	$13,250	$27,455

CEP also argues that TGS failed to provide specific evidence with respect to certain operational and administrative efficiencies identified by TGS's witnesses, or their specific rate impact to customers.[57] CEP offers that consolidation here is not proper because the EPSA, PSA, and DCSA are "geographically discrete, not connected by any TGS pipeline, have different gas supplies, and have different system characteristics."[58] According to CEP, these factors distinguish this case from the prior Commission dockets relied upon by TGS, where the Commission approved system-wide rates.[59]

Coalition characterizes the proposed consolidation as "transparent cost-shifting" that hikes rates for current EPSA customers to subsidize the smaller PSA and DCSA.[60] Coalition also argues that the majority of the prior Commission dockets cited by TGS, where the Commission approved system-wide rates, was the result of settled negotiations and therefore cannot constitute established Commission policy.[61] According to Coalition, the EPSA, PSA, and DCSA are "independent and isolated" from each other and the sharing of networks is "minimal to nonexistent," and therefore consolidation would not be of any benefit to customers.[62] Like CEP, Coalition states that the result of service area consolidation would be "discriminatory" and "prejudicial."[63] In its exceptions to the PFD, Coalition states that TGS's own service map[64] "shows the immense distance and sprawl among the areas proposed for consolidation."[65] Coalition further states EPSA rates "should be lower because its population is denser, pipe distances are closer making attendant maintenance and operations costs lower, and capital investment less."[66]

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[56] City of El Paso's Exceptions to Proposal for Decision, filed on Sept. 9, 2016 ("CEP Exceptions"), at 4 (citing to the evidentiary record).

[57] *See* CEP Initial Br. at 6-9; *see also* Reply Brief of the City of El Paso, filed Aug. 10, 2016 ("CEP Reply Br."), at 5-6.

[58] *See* CEP Initial Br. at 2-9.

[59] *See id*. at 6; *see also* CEP Reply Br. at 4-5, 7.

[60] Initial Brief of the Coalition of Cities Served by Texas Gas Service Company, filed Aug. 3, 2016 ("Coalition Initial Br."), at 1-2.

[61] *Id*. at 2.

[62] *Id*. at 2-4.

[63] *Id*. at 3-4 ("In fact, TGS's proposed rates for the EPSA under consolidation present a hefty hike to those customers. This result alone is unreasonable, preferential, prejudicial and discriminatory, and in conflict with state law.").

[64] *See* Attachment B to this Amended PFD.

[65] Coalition of Cities Exceptions to the Proposal for Decision, filed on Sept. 9, 2016 ("Coalition Exceptions"), at 2.

[66] *Id*. at 2-3.

In response to CEP and Coalition, TGS argues that prior Commission dockets establish precedent supporting consolidation, and that CEP and Coalition misstate the rate impact of consolidation. TGS states that it will not earn more revenues through consolidation, as argued by CEP and Coalition, and that any increased revenues from one area under consolidation will be offset by decreased revenues from other areas.[67] TGS also maintains that consolidation does not result in a "hefty" rate hike; rather, the vast majority of the increase in the EPSA in this case is caused primarily by changes to the revenue requirement in the EPSA, not the effects of consolidation.[68] TGS offers that, under consolidation, average EPSA residential bills increase by only $0.29 more than they would without consolidation.[69] TGS also states the geographic distance among the WTSA cities is similar to distances among cities in service areas by other Texas gas utilities, and that interconnection of facilities has no bearing on the consolidation decision in this case.[70]

Examiner Findings and Recommendation

Despite liberal use by parties of the word "precedent" on this issue, no prior Commission or Texas court decision binds the Commission here to approve or disapprove service area consolidation. The Commission can—and should—decide this issue based on the facts and evidence unique to this case, applying the proper legal standard. The Examiners, having done this, recommend that TGS's proposed service area consolidation be approved.

<u>Legal Standard and Prior Cases</u>

The Commission, in its informed discretion, may approve service area consolidation if it considers consolidation to be appropriate and in the public interest. While no statute speaks directly to service area consolidation, the Legislature and Third Court of Appeals have provided the Commission with general guidance. GURA Section 101.002 (Purpose and Findings) provides that "[GURA] is enacted to protect the public interest inherent in the rates and services of gas utilities."[71] GURA Section 104.003 (Just and Reasonable Rates) authorizes the Commission to treat as a single class two or more municipalities that a gas utility serves if the Commission considers that treatment to be "appropriate."[72] In *City of Dallas*, the Court of Appeals stated that the geographic aspects of rate design are left to the Commission's "informed discretion."[73]

While not binding on the Commission to determine this issue in TGS's favor, the Court of Appeals has informed the type and sufficiency of evidence needed to meet the above standard. In *City of Dallas*, the Court of Appeals concluded that the Commission had a reasonable basis for approving rates applicable to all areas in Texas served by a gas utility.[74] In that case, the

[67] Reply Brief of Texas Gas Service Company, a Division of ONE Gas, Inc., filed Aug. 10, 2016 ("TGS Reply Br."), at 4-5.
[68] *Id*. at 5.
[69] *Id*.; *see also* TGS Ex. 17, Direct Testimony of F. Jay Cummings on Behalf of Texas Gas Service Company ("Cummings Test."), at Exhibits FJC-5 and FJC-6.
[70] TGS Reply Br. at 4.
[71] Tex. Util. Code § 101.002(a).
[72] *Id*. § 101.003(a).
[73] *See City of Dallas*, 2008 WL 4823225, at *9 (citing *Nucor Steel v. Pub. Util. Com'n of Texas*, 168 S.W.3d 260, 269 (Tex. App.—Austin 2005, no pet.)).
[74] *Id*. at *7-10.

utility's rates previously had been set on a municipality-by-municipality or region-by-region basis. The party opposing consolidation in *City of Dallas* made virtually the same principal arguments that CEP and Coalition now make: that there had been a historical practice of setting separate rates for the service areas; that one such service area was an "integrated system" with a lower cost of service compared to other areas served by the utility; that shifting to system-wide rates would force customers in one locality "to subsidize" customers in other parts of the state; and that consequently the system-wide rates were "discriminatory" to the customers in that area.[75] Considering these arguments, the Court of Appeals nevertheless found substantial evidence to support the Commission's approval of system-wide rates, noting the wide discretion of the Commission.[76]

No Basis for Discrimination

TGS's proposed service area consolidation is not discriminatory or prejudicial. There is no credible evidence that TGS's proposed consolidation constitutes—or results in—a "discriminatory" or "prejudicial" act, as argued by CEP and Coalition. On the contrary, the evidence shows that TGS's proposed consolidation would result in system-wide rates for all EPSA, PSA, and DCSA customers in the newly-formed WTSA. As the Court of Appeals has made plain, system-wide rates *avoid* unreasonable rate differences between localities or between classes of service.[77] There is no credible evidence that TGS will charge unreasonably different rates between localities or between classes of service in the proposed WTSA once it is formed. Accordingly, there is no merit to claims that consolidation is discriminatory or prejudicial to anyone.

WTSA

Here, the weight of the evidence supports consolidation. In making this finding, the Examiners gave no weight to prior Commission dockets since they do not bind the Commission here and involve different facts. The Examiners considered the holding in *City of Dallas* only to the extent that the Court of Appeals informed the applicable legal standard for service area consolidation in Texas, as well as the type and sufficiency of evidence needed to meet that standard. As far as evidence considered, the Examiners looked only to the facts unique to TGS's proposed consolidation of the EPSA, PSA, and DCSA in this docket, as contained in the evidentiary record.

TGS demonstrated through credible testimony that consolidating the EPSA, PSA, and DCSA into a single WTSA is likely to result in numerous administrative and regulatory efficiencies, and those efficiencies will benefit WTSA customers. Specifically, consolidation likely will reduce the number of cost-of-service analyses and rate-filing packages that TGS must prepare each time it seeks to change rates within these areas. This allows rate changes to be implemented uniformly and consistently, which is more economical, efficient, and cost-effective for TGS and its customers.

TGS also demonstrated that a consolidated WTSA will better reflect existing centralized operations, management, and decision-making processes. At the ONE Gas level, certain

[75] *Id.* at *1, 9.
[76] *Id.* at *10.
[77] *See id.* at *9 ("There is no dispute that uniform, statewide rates would comply with these requirements.").

activities—such as project planning and management—now are organized around function rather than geography. At the TGS level, many employees now have responsibilities for certain functions across many service areas.

In opposition, CEP and Coalition make essentially the same arguments considered by the Court of Appeals in *City of Dallas*: that the EPSA historically has had its own rates, it is an integrated system with a lower cost of service compared to the PSA and DCSA, and that consequently the EPSA customers will be "subsidizing" PSA and DCSA customers in the consolidated WTSA. While the factual circumstances in *City of Dallas* are different than here—as correctly noted by CEP and Coalition[78]—the Court of Appeals in that case found substantial evidence to support the Commission's approval of system-wide rates, despite essentially the same arguments in opposition.

The *City of Dallas* holding does not bind the Commission to make the same determination here, but it does inform that these opposition arguments may not address sufficiently—and perhaps may avoid—the legal standard that consolidation be appropriate and in the public interest. CEP and Coalition both argue, convincingly, that consolidation may result in EPSA customers paying higher rates in the future in the consolidated WTSA than they otherwise might as a standalone service area. In fact, the evidence supports this.[79] However, the "public interest" may be broader than the specific interests of any one locality or its customers, and may include more than quantifiable rate impacts. Here, even if these opposing arguments are accepted as true, the weight of the evidence still shows that consolidation likely will result in numerous operational and administrative efficiencies beneficial to *all* customers in the proposed WTSA.

Furthermore, the EPSA-focused arguments by CEP and Coalition do not consider that the Commission must also balance the interests of TGS. The Legislature makes plain that the purpose of GURA is "to establish a comprehensive and adequate regulatory system for gas utilities to assure rates, operations, and services that are just and reasonable to the customers *and to the utilities*."[80] Though regulated, gas utilities are not guaranteed a profit. Rather, they are afforded the *opportunity* to earn a reasonable return on their invested capital used and useful in providing service to the public in excess of their reasonable and necessary operating expenses.[81] It is illogical, then, to require gas utilities to strive for efficiency in their operations to earn a reasonable return, while at the same time denying them opportunities to economize and streamline their operations by consolidating service areas—where doing so is appropriate and in the public interest.

[78] *See, e.g.*, Coalition Exceptions at 2 ("In [*City of Dallas*], the service area in Dallas and the surrounding areas were in fact, one large, integrated and interconnected area that had developed to the extent that they had become adjacent and almost indistinguishable from each other.").
[79] *Compare* TGS Ex. 17 (Cummings Test.) at Exhibit FJC-5 with Exhibit FJC-10 (showing the average EPSA residential bills increasing in certain cases by $0.29 more with consolidation than without consolidation).
[80] Tex. Util. Code § 101.002 (Purpose and Findings) (emphasis added).
[81] *Id*. § 104.051 (Establishing Overall Revenues).

Conclusion

Considering the evidence, the Examiners find that consolidation of the EPSA, PSA, and DCSA into a single WTSA is appropriate and in the public interest. Accordingly, the Examiners recommend that TGS's proposed service area consolidation be approved.

VIII. REVENUE REQUIREMENT

The Commission is required to establish TGS's overall revenues at an amount that will permit TGS a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.[82] Here, TGS requests a total revenue requirement of $82,613,050.[83] As treated below, the Examiners recommend that TGS's total revenue requirement be $78,171,546.

A. Rate Base

TGS requests a total rate base amount of $266,650,553. This represents TGS's invested capital used to provide gas utility service to its customers. The majority of TGS's capital investment has not been challenged and therefore is presumed to have been reasonably and necessarily incurred.[84] The few rate base issues that are in dispute are capital investment for the Journey program ("Journey"), sales tax amounts, cash working capital ("CWC"), and TGS's use of a "tapping fee" mechanism for certain customers.

CEP recommends a reduced rate base of $259,747,532. CEP primarily recommends that Journey be excluded. CEP also estimates a higher negative CWC amount, something that would reduce the rate base further. In support, CEP provided testimonial evidence from Mark Garrett (J.D.), an attorney, certified public accountant, and President of Garrett Group, LLC, a firm specializing in public utility regulation, litigation, and consulting services.[85]

Staff's recommended rate base amounts do not differ from those contained in TGS's revised schedule.[86] Staff contends that TGS's use of a "tapping fee" mechanism is discriminatory and recommends its elimination, which would increase plant in service by $623,804.[87] Staff also recommends removal from plant in service of $32,262 in duplicative sales tax.[88] In support, Staff provided testimonial evidence from Erin Cromleigh (Financial Analyst in the Market Oversight Section of the Oversight and Safety Division) and Sarah Montoya (Financial Analyst in the Market Oversight Section of the Oversight and Safety Division).

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[82] Tex. Util. Code § 104.051 (Establishing Overall Revenues).
[83] In its original SOI, TGS requested a revenue requirement of $82,124,177.
[84] *See* 16 Tex. Admin. Code § 7.503(a) (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities).
[85] CEP Ex. 2, Direct Testimony of Mark E. Garrett ("Garrett Test."), at 3.
[86] TGS Ex. 20, Rebuttal Testimony of Janet L. Buchanan on Behalf of Texas Gas Service Company ("Buchanan Rebuttal Test."), at 10, 12.
[87] Staff Ex. 2, Direct Testimony of Erin Cromleigh, as redacted ("Cromleigh Test."), at 22.
[88] Staff Ex. 3, Direct Testimony of Sarah Montoya ("Montoya Test."), at 8.

1. Journey Program

Journey is a major point of disagreement between TGS and CEP/Coalition. Journey costs allocated to the WTSA amount to $7,232,049, which is 10.2 percent of Journey's total cost of $71,130,684 for ONE Gas. TGS describes Journey as a multi-year transformational program consisting of initiatives focused on improving organization, processes, and technology to enhance ONE Gas's ability to operate efficiently and provide safe and reliable service to customers, including TGS's customers.[89] According to TGS, Journey has improved the reliability of service and given TGS improved insight into operations, including construction and maintenance.[90] TGS offers that its customers already benefit from this program because Journey investment:

- aids TGS in prioritizing pipeline replacements so that capital investments are made in a cost-effective and efficient manner;[91]
- includes a work management system that facilitates the collection of more accurate, complete, and timely data for record-keeping and compliance purposes;[92]
- includes technology solutions for the work management system used for work related to system assets, including preventative maintenance, corrective maintenance, construction, compliance, and leak management activities;[93]
- has replaced outdated manual processes allowing TGS to use computer-aided dispatch for construction crews, which allows data to be gathered and uploaded as it is acquired;[94] and
- to the extent cost efficiencies have been achieved, those efficiencies are reflected in the test-year costs.[95]

Staff does not oppose inclusion of Journey in rate base, as proposed by TGS.

Opposition by CEP and Coalition

In opposition, CEP and Coalition object to the inclusion of Journey, arguing that TGS failed to establish or quantify any benefit included in test-year expenses. CEP pointed out that Journey had a cost estimate of $77 million and ultimately would produce savings of $30 million by 2020, but TGS did not include an adjustment to apportion savings to ratepayers.[96] CEP explains that, by excluding Journey from rate base, TGS can retain all of the operating benefits generated by Journey until TGS's next rate case.[97] CEP argues that Journey is not actually used and useful until it is generating the benefits it was designed to produce.[98] CEP explained that

[89] TGS Ex. 18, Rebuttal Testimony of Caron A. Lawhorn on Behalf of Texas Gas Service Company ("Lawhorn Rebuttal Test."), at 2.
[90] Tr. at 53-54 (July 19, 2016) (Lawhorn testifying).
[91] TGS Ex. 18 (Lawhorn Rebuttal Test.) at 4.
[92] *Id*. at 5.
[93] *Id*. at 2.
[94] Tr. at 55-56 (July 19, 2016) (Lawhorn testifying).
[95] Tr. at 55 (July 19, 2016) (Lawhorn testifying); Tr. at 171 (July 20, 2016) (Lawhorn testifying).
[96] CEP Ex. 2 (Garrett Test.) at 46.
[97] *Id*. at 48.
[98] *Id*.

because TGS can take advantage of the GRIP statute, the cost savings benefits between now and 2023 are potentially lost to ratepayers.[99] In support, CEP cites a 2011 Nevada utility case, which CEP argues is analogous.[100] In that case, according to CEP, the Nevada Commission excluded the full costs of a similar initiative because the utility did not quantify and include the savings from the project in its pro forma revenue requirement, and instead allowed the utility to retain all of the savings generated by the project until the utility's next rate case.[101]

In rebuttal, TGS argues that CEP's proposed disallowance of TGS's Journey capital investment is not supported by the evidence or applicable statutory standards. TGS states that CEP is unable to point to a single Texas statute, rule, or case that supports CEP's proposed adjustment.[102] TGS also notes that CEP does not challenge that the Journey-related investment is used and useful, nor has it alleged that the investment is imprudent.[103] TGS also states that the out-of-state Nevada electric case cited by CEP has no nexus to Texas law and should not be considered.[104]

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that Journey-related assets: are used and useful in providing service to customers; currently are in service; and increase the safety and reliability of the system, including assets in the WTSA. TGS demonstrated that Journey benefits customers, and that those benefits will increase over time. Including Journey in rate base will allow TGS an opportunity to earn a reasonable return on capital investment for projects that are used and useful in providing service. Accordingly, the Examiners find that TGS's request to recover its proposed capital investment related to Journey is proper under GURA Section 104.051 (Establishing Overall Revenues). The Examiners recommend that Journey-related assets be included in rate base, as proposed by TGS.

2. Sales Tax Adjustment

TGS included $32,262 of duplicative sales tax in its plant in service. Staff and TGS discovered this error during discovery following a discovery request propounded by Staff.[105] Staff recommends removing this $32,262 in duplicative tax from Plant in Service through eleven distinct FERC accounts and that TGS take corrective action to prevent incidents of duplicative taxation in the future.[106]

In its rebuttal testimony, TGS acknowledged its mistake and agrees that this additional tax should be excluded from rate base.[107] TGS agrees with Staff's recommendation and offers that TGS currently is in the process of developing additional training to address this issue, and is upgrading its software system to help decrease the likelihood of similar errors in the future.[108]

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[99] *Id*. at 46-49
[100] *See id*. at 48-49.
[101] *Id*.
[102] TGS Reply Br. at 6.
[103] *Id*. at 7.
[104] *Id*. at 7-8.
[105] Staff Ex. 3 (Montoya Test.), at 5-8.
[106] *Id*. at 7.
[107] TGS Ex. 20 (Buchanan Rebuttal Test.) at 12.
[108] *Id*.

The Examiners and all parties agree that the duplicative tax amount of $32,262 should be removed from Plant in Service. The Examiners recommend that affected customers be made whole for this overcharge through a bill credit.

3. Cash Working Capital (CWC)

The term "cash working capital" refers to the net funds required by TGS to pay for goods and services between the time they are paid for by TGS and the time revenues are recovered from customers.[109] For TGS, the cost of goods and services includes: purchased gas expenses; operations and maintenance expenses, including labor and non-labor expenses; federal, state, and local taxes; and employment taxes.[110] TGS proposes a negative CWC request of $3,593,340, meaning that TGS received revenue faster than it paid out expenses during the test year. This amount is a reduction to rate base and thus a lower revenue requirement than if the CWC were zero. The CWC amount was determined by a lead-lag study that, according to TGS, used the same methodologies that have been traditionally used in rate cases before the Commission.[111]

Staff does not oppose TGS's proposed CWC.

Opposition by CEP

CEP's sole point of opposition to TGS's proposed CWC concerns interest expense for interest on long-term debt. CEP proposes that this expense should be included in TGS's calculation.[112] According to CEP, long-term debt interest should be included in the CWC study because the expenses are cash and are non-discretionary contractual payments.[113] CEP explains that TGS can use the cash in the period between when it is collected from ratepayers each month until it is paid out to bondholders twice a year.[114]

In rebuttal, TGS argues that CEP's proposal to include interest on long-term debt in TGS's calculation is contrary to long-standing Commission precedent and sound ratemaking principles.[115] According to TGS, the Commission has consistently held that long-term debt interest is a non-cash item and is excluded from CWC.[116] TGS further states that CEP's argument that the Commission should overrule its past precedent and adopt the precedent of other jurisdictions is unpersuasive and that CEP misstates that precedent.[117]

[109] TGS Ex. 14, Direct Testimony of Joshua C. Nowak on Behalf of Texas Gas Service Company ("Nowak Test."), at 2.
[110] *Id*.
[111] *Id*. at 4; TGS Ex. 8, Direct Testimony of Janet L. Buchanan on Behalf of Texas Gas Service Company ("Buchanan Test."), at 18.
[112] CEP Ex. 2 (Garrett Test.) at 6-13.
[113] *Id*. at 5.
[114] *Id*. at 6-13.
[115] TGS Ex. 23, Rebuttal Testimony of Joshua C. Nowak on Behalf of Texas Gas Service Company ("Nowak Rebuttal Test."), at 2-8 (citing GUD Nos. 10170, 10000, 9902, 9869, 9670, 9400, and 9145).
[116] *Id*.
[117] *Id*. at 6-7.

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that TGS's proposed CWC is just and reasonable, including the calculation methods used. The weight of the evidence supports TGS's proposed CWC amount and that interest on long-term debt should be excluded. Accordingly, the Examiners recommend approval of TGS's proposed CWC.

4. Tapping Fees

Tapping fees are a major point of disagreement between TGS and Staff. In TGS's proposed Rules of Service for the WTSA is a monthly payment option termed "tapping fees"—available specifically to new customer groups "outside the City Limits of the City of El Paso" ("Tapping Fee Eligible Customers") as a payment option for paying the costs associated with line extensions to those customer groups.[118] TGS treats the costs associated with these line extensions as "Contribution in Aid of Construction" ("CIAC"), which is different from TGS's treatment of the costs associated with other line extensions, recovered through rates.[119] The other payment option for Tapping Fee Eligible Customers is an upfront, lump-sum CIAC payment. Per the terms of the proposed Rules of Service, TGS may, at its option, require a "one time lump sum CIAC amount" if the monthly tapping fee is not "economical or reasonable."[120]

According to TGS, the monthly tapping fee provision originally was implemented because there were many underdeveloped, impoverished areas outside of the City of El Paso without adequate utility service.[121] Residents in these "colonias" areas were unable to pay an upfront, lump-sum CIAC payment, and the monthly tapping fee provision allowed these residents to get utility service and pay the contribution in installments over time.[122] TGS states that if the monthly tapping fee provision is discontinued, then these colonias areas in the future will be able to obtain gas service only under TGS's regular line extension policy, which may require the payment of an upfront, lump sum CIAC payment.

CEP does not oppose TGS's monthly tapping fee provision and Coalition urges that it remain in place.

Opposition by Staff

Staff opposes TGS's monthly tapping fee provision because it applies only "to the colonias" rather than to all customers in the WTSA, and therefore may be discriminatory.[123] According to Staff, allowing Tapping Fee Eligible Customers to make CIAC payments in monthly installments gives them preferential treatment and an unreasonable advantage over other customers—inside and outside the city limits—who do not have a monthly payment option.[124] Staff also states that it is unaware of any other utility in Texas using an arrangement similar to

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[118] *See* TGS Ex. 1 (SOI), Exhibit A (Rate Schedules), pp. 86-87.
[119] *See id.*, pp. 84-87.
[120] *Id.*, pp. 86-87.
[121] TGS Ex. 19, Rebuttal Testimony of Stacey L. McTaggart on Behalf of Texas Gas Service Company ("McTaggart Rebuttal Test."), at 9-10.
[122] *Id.* at 10.
[123] Staff Ex. 2 (Cromleigh Test.) at 20-23; Staff Initial Br. at 15-17.
[124] Staff Ex. 2 (Cromleigh Test.) at 21-22; Staff Initial Br. at 16-17.

tapping fees, and therefore it is not typical industry practice.[125] Staff also notes that TGS does not have this policy in any other service area in the state.[126] Ultimately, Staff recommends that TGS: include the remaining balance of CIAC associated with the colonias in the cost of service, withdraw all tapping fee rate schedules on file with the Commission, and treat all residential customers equally with respect to rates and services in this case and in the future.[127]

In response, TGS disagrees that its tapping fee provision is discriminatory, maintaining that monthly tapping fees give colonias residents a way to contribute financially to TGS's extension of service—the same as any other customer must contribute financially through an advance or a CIAC—if a line extension otherwise is not cost effective for TGS.[128] According to TGS, the only difference between a tapping fee and a typical line extension that requires a financial contribution is that the tapping fee is spread over time rather than paid in a lump sum.[129]

Additionally, Coalition urges that TGS's monthly tapping fee provision not be discontinued.[130] Coalition offers that colonias areas are "problematic and can be dire in Texas, particularly along the Texas-Mexico border."[131] According to Coalition, tapping fees provide a benefit not only to the colonias, but also to ratepayers by the avoidance of future potential costs resulting from "mismanagement of development and growth in these areas."[132]

Examiner Findings and Recommendation

Staff's general discrimination concern raises two distinct issues: (1) whether the tapping fee provision would be discriminatory because it would not be available to WTSA customers in incorporated areas; and (2) whether the tapping fee provision would be discriminatory because it would not be available to WTSA customers in unincorporated areas not specifically located outside the El Paso city limits. These two issues are treated separately, below.

Tapping Fee Eligible Customers vs. Incorporated Customers

The monthly tapping fee provision would not discriminate against residential customers within the WTSA's incorporated areas. GURA Section 104.004 (Unreasonable Preference or Prejudice Prohibited) states that a utility may not: (1) grant an unreasonable preference or advantage concerning rates or services to a person in a classification; (2) subject a person in a classification to an unreasonable prejudice or disadvantage concerning rates or services; or (3) establish or maintain an unreasonable difference concerning rates of services between localities or between classes of service.[133] To construe this statue to require perfectly identical treatment of all WTSA customers is too rigid and ignores this statute's plain language that any preference,

[125] Staff Initial Br. at 16.
[126] *Id*. at 17.
[127] Staff Ex. 2 (Cromleigh Test.) at 23.
[128] TGS Ex. 19 (McTaggart Rebuttal Test.) at 10; TGS Reply Br. at 7-8.
[129] *Id*.; Tr. at 185-86 (July 20, 2016) (McTaggart testifying).
[130] Coalition Initial Br. at 7 ("While the tapping fee is more a question of policy, the Coalition urges, nonetheless, that it remain in place until and when the Commission develops and implements policy on this matter.").
[131] *Id*.
[132] *Id*.
[133] Tex. Util. Code § 104.004 (Unreasonable Preference or Prejudice Prohibited).

advantage, prejudice, disadvantage, or difference is only prohibited to the extent it is *unreasonable*.

Here, the tapping fee provision plainly excludes the City of El Paso's incorporated customers: "The Company may, at its option, extend lines to serve a group of new Customers outside the City Limits of the City of El Paso…"[134] To the extent this language excludes all WTSA incorporated customers,[135] the Examiners find that allowing only customers in unincorporated areas to pay CIAC amounts in monthly installments does not amount to a "preference," "advantage," "prejudice," or "disadvantage"—unreasonable or otherwise. The evidence does not show that Tapping Fee Eligible Customers would pay a lesser CIAC payment via monthly installments than with an upfront, lump-sum payment, or that the monthly fee payments would differ from the terms of the rate schedules on file with the Commission. The Examiners do find that the tapping fee provision constitutes a "difference concerning rates of service," but the difference is reasonable and in the public interest. The evidence shows that allowing customers in unincorporated areas to pay CIAC amounts in installments, rather than lump-sum payments, benefits underdeveloped and impoverished communities by providing a quicker and easier path to reliable utility service.

Tapping Fee Eligible Customers vs. Customers Located Near Other WTSA Cities

To the extent the tapping fee language applies only to customers that are outside—but geographically near—the City of El Paso, the Examiners find that this provision would violate GURA Section 104.004 (Unreasonable Preference or Prejudice Prohibited) by unreasonably allowing only certain—but not all—unincorporated customers in the WTSA to pay CIAC amounts in monthly installments. The evidence does not show why it would be reasonable to allow installment payments only to unincorporated customers near the City of El Paso but not to unincorporated customers near other WTSA cities.

The Examiners do not recommend discontinuing the tapping fee provision, but rather recommend expanding the intended—or clarifying the strict and literal—existing language. In the original PFD, the Examiners recommended the following replacement language for the first paragraph of the tapping fee provision:

> 8.9 TAPPING FEE
> The Company may, at its option, extend lines to serve a group of new Customers outside the incorporated areas of the West Texas Service Area (WTSA) by the use of Contribution In Aid of Construction (CIAC). Unless not economical or reasonable, the Company shall allow payment of the CIAC amount in the form of a monthly Tapping Fee charged to the existing and subsequent Customers in the area to be served. The fee will continue to be charged to all Customers connecting to the Extension of Facilities each month until the Company recovers the amount of CIAC required to serve the area. At least fifty (50) percent of the existing homes in the area must be under contract for service for this type of Extension of Facilities to be available to the area.

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[134] TGS Ex. 1 (SOI), Exhibit A (Rate Schedules), p. 86; *see also id*., pp. 70 (defining "Customer" as "[A]ny person or organization now being billed for gas service whether used by him or her, or by others.").

[135] Through a strict and literal reading, this language could apply to *all* customers "outside of the City Limits of the City of El Paso"—including those in other WTSA incorporated areas.

In its exceptions to the PFD, TGS proposed expanding this language not just to all WTSA environs customers, but to all TGS customers located outside or inside the WTSA incorporated areas.[136] TGS requests that the proposed language for Section 8.9 in the Rules of Service be revised to state the following:

> 8.9 TAPPING FEE
> The Company may, at its option, extend lines to serve a group of new Customers outside or inside the incorporated areas of the West Texas Service Area (WTSA) by the use of a Contribution In Aid of Construction (CIAC).[137]

The Examiners find that this revision is just and reasonable and would not be discriminatory to any WTSA customers.

Conclusion

Considering the evidence, the Examiners find that TGS's tapping fee provision—if revised with TGS's proposed replacement language contained in its exceptions to the PFD—would not be discriminatory to any customers in the WTSA. Subject to this revision, the Examiners recommend that the Commission allow TGS's use of tapping fees to continue.

5. Pension and FAS 106 Regulatory Asset

TGS requests inclusion of $877,764 in rate base for Pension and FAS 106 Regulatory Asset. GURA Section 104.059 (Pension and Other Postemployment Benefits) allows a gas utility to establish reserve accounts for tracking changes in the cost of pensions and other postemployment benefits.[138] TGS records in a reserve account the difference between the annual amount of pension and other postemployment benefits approved and included in TGS's current rates, and annual amount of costs for pension and other postemployment benefits as determined by actuarial or other similar studies.[139]

No intervenor challenged this amount.

Examiner Findings and Recommendation

The Examiners find the test year level of pension-related and other post-employment benefits expenses to be just, reasonable, necessary, and consistent with GURA Section 104.059 (Pension and Other Postemployment Benefits). The Examiners recommend the following be adopted:

[136] Exceptions of Texas Gas Service Company, a Division of ONE Gas, Inc., to the Proposal for Decision, filed on Sept. 9, 2016 ("TGS Exceptions"), at 17.
[137] *Id*. (emphasis in original).
[138] *See* Tex. Util. Code § 104.059 (Pension and Other Postemployment Benefits).
[139] TGS Ex. 8 (Buchanan Test.) at 17.

Table 2 - Pension and Other Postemployment Benefits 104.059[140]

FERC Account No.	Description	Amount
1823	Regulatory Assets Deferred Pension Test Year Beginning Balance	$ 937,871
1823	Regulatory Assets Deferred OPEB Test Year Beginning Balance	$ 81,468
	TOTAL	$ 1,019,339
4073	Regulatory Assets Deferred Pension Amortization Through Dec. 2015	$ (130,260)
4073	Regulatory Assets Deferred OPEB Amortization Through Dec. 2015	$ (11,315)
	TOTAL	(141,575)
1823	Pension and FAS 106 Regulatory Asset Dec. 2015 Ending Balance	$ 877,764

6. Prepaid Pension Asset

TGS included in its rate base a prepaid pension asset totaling $9,145,462. The revenue requirement impact of including this prepaid asset in rate base is approximately $644,351. [141] Plan expense is determined in accordance with Financial Accounting Standards Board ("FASB") standards and funding is regulated by the Employee Retirement Income Security Act ("ERISA") and the Pension Protection Act ("PPA").[142] According to TGS, including this asset in rate base increases the revenue requirement by $644,351, but it also has the impact of reducing current year expense by $1.8 million for TGS and by $708,000 for the WTSA, a net benefit to ratepayers.[143]

No intervenor contested the inclusion of this asset in rate base.

Examiner Findings and Recommenation

Considering the evidence, the Examiners find that inclusion in rate base of the prepaid pension asset totaling $9,145,462 is just and reasonable. The evidence shows that this investment benefits ratepayers by reducing expenses by more than the rate of return earned on the asset, and also avoids future additional costs and restrictions being placed on the pension plan. Accordingly, the Examiners recommend that this asset be included in rate base.

7. Unchallenged Amounts

As found above, TGS established that it keeps its books and records in accordance with Commission rules. Accordingly, the unchallenged amounts shown on TGS's books and records,

[140] Schedule B-4.
[141] TGS Ex. 10, Direct Testimony of Mark W. Smith on Behalf of Texas Gas Service Company ("Smith Test."), at 2-11.
[142] *Id*. at 2-11.
[143] *Id*. at 9-11.

as well as summaries and excerpts therefrom, are presumed to have been reasonably and necessarily incurred.[144]

8. Rate Base Conclusion

The Examiners find that a rate base amount totaling $266,006,743 is just and reasonable, supported by the evidence, and consistent with the requirements of GURA Chapter 104 (Rates and Services).

B. Rate of Return

The Commission may not establish a rate that yields more than a fair return on the adjusted value of the invested capital used and useful in providing service to the public.[145] TGS proposes that the rate of return be set at 7.59 percent based on the below capital structure and costs.

Table 3: TGS Recommended Rate of Return			
	Capital Structure	Cost	Weighted Average
Long-Term Debt	39.9%	3.95%	1.58%
Common Equity	60.1%	10%	6.01%
Rate of Return	**7.59%**		

In support, TGS provided testimonial evidence from Bruce H. Fairchild (Ph.D., Finance, Accounting, and Economics).[146]

In opposition, CEP recommends that the rate of return be set at 6.73 percent based on the below capital structure and costs.

Table 4: CEP Recommended Rate of Return			
	Capital Structure	Cost	Weighted Average
Long-Term Debt	45%	3.95%	1.78%
Common Equity	55%	9%	4.95%
Rate of Return	**6.73%**		

In support, CEP provided testimonial evidence from Daniel J. Lawton (M.A., Economics).[147]

[144] *See* 16 Tex. Admin. Code § 7.503(a) (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities).
[145] Tex. Util. Code § 104.052 (Establishing Fair Rate of Return).
[146] TGS Ex. 16, Direct Testimony of Bruce H. Fairchild on Behalf of Texas Gas Service Company (“Fairchild Test.”); TGS Ex. 25, Rebuttal Testimony of Bruce H. Fairchild on Behalf of Texas Gas Service Company (“Fairchild Rebuttal Test.”).
[147] CEP Ex. 1, Direct Testimony of Daniel J. Lawton on Behalf of The City of El Paso, Texas (“Lawton Test.”).

Also in opposition, Staff recommends that the rate of return be set at 7.14 percent based on the below capital structure and costs.

Table 5: Staff Recommended Rate of Return			
	Capital Structure	Cost	Weighted Average
Long-Term Debt	39.9%	3.95%	1.58%
Common Equity	60.1%	9.25%	5.56%
Rate of Return	**7.14%**		

In support, Staff provided testimonial evidence from Frank M. Tomicek, Financial Analyst in the Commission's Market Oversight Section of the Gas Services Division.[148]

The components of rate of return—capital structure, cost of debt and cost of equity—are treated individually below.

1. Capital Structure

TGS proposes using ONE Gas's September 30, 2015 capital structure ratios of 39.9 percent debt and 60.1 percent equity.[149] According to TGS, this capital structure reflects how TGS is actually financed and follows the Commission's practice of using a utility's actual capital structure ratios when they fall within industry bounds.[150] In support, TGS states that as an operating division of ONE Gas it has no independent financing, and it relies entirely on ONE Gas—its parent company—for capital to finance its investment in assets, including those in the WTSA.[151]

Staff supports TGS's proposed capital structure. Staff states that its preference is to use the actual capital structure of a utility when the actual capital structure is consistent with those of publicly-traded gas distribution utilities within this segment of the industry, and the capital structure that TGS proposes is based on that reported in TGS's most recent SEC Form 10-K annual report filing for ONE Gas.[152]

Opposition by CEP and Coalition

In opposition, CEP and Coalition recommend setting a hypothetical capital structure of 55 percent common equity and 45 percent long-term debt. CEP provided three explanations for its recommendation: *first*, CEP argues that TGS's proposed capital structure is out of line with capital structures of comparable risk companies, showing that the average equity ratio for the comparable group average is—at most—53.75 percent in the 2016 forecast period;[153] *second*, CEP claims that TGS provided no evidence of it having a goal to maintain an equity ratio in the

[148] Staff Ex. 1, Direct Testimony of Frank M. Tomicek, CRRA ("Tomicek Test.").
[149] TGS Ex. 16 (Fairchild Test.) at 16.
[150] *Id*.
[151] *Id*. at 14.
[152] Staff Ex. 1 (Tomicek Test.) at 5.
[153] CEP Ex. 1 (Lawton Test.) at 36.

60-percent range;[154] and *third*, CEP points out that ONE Gas agreed to lower equity ratios in both Oklahoma and Kansas and that it is not reasonable to treat Texas ratepayers differently.[155]

In rebuttal, TGS responded to each of CEP's three arguments. First, TGS showed that at least three of the eight natural gas local distribution companies ("LDCs") in its proxy group had equity ratios above 60 percent at their fiscal year-ends 2011 through 2014.[156] TGS noted that these LDCs are longstanding companies not needing to establish creditworthiness to attract new capital on reasonable terms and maintain their financial integrity, as ONE Gas does.[157] Second, TGS explained that ONE Gas's capital structure is known, has remained essentially unchanged since the end of the test year, and no evidence that ONE Gas intends to alter its existing capital structure ratios.[158] Third, TGS noted that the lower equity ratios in Kansas and Oklahoma were part of settlement agreements.[159]

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that TGS's proposed capital structure of 60.1 percent equity and 39.9 percent long-term debt is just and reasonable, supported by the weight of the evidence, and consistent with the requirements of GURA Chapter 104 (Rates and Services). TGS demonstrated: that this equity ratio reflects TGS's actual capital structure, that this equity ratio is within the range of industry norms, and that TGS has maintained an equity ratio of approximately 60 percent since 2014. Accordingly, the Examiners recommend approval of TGS's proposed capital structure.

2. Cost of Debt

TGS proposes the cost of debt be set at 3.95 percent. TGS provided evidence that a 3.95-percent cost of debt is the average cost at September 30, 2015, of the $1.2 billion of long-term debt issued by ONE Gas in connection with its spinoff from ONEOK in 2014.[160]

No parties opposed TGS's proposed cost of debt.

Examiner Findings and Recommendations

Considering the evidence, the Examiners find that a 3.95-percent cost of debt is just and reasonable, supported by the weight of the evidence, and consistent with the requirements of GURA Chapter 104 (Rates and Services). TGS demonstrated that a 3.95-percent cost of debt is the average cost at September 30, 2015, of the $1.2 billion of long-term debt issued by ONE Gas in connection with its spinoff from ONEOK in 2014. Accordingly, the Examiners recommend approval of TGS's proposed cost of debt.

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[154] *Id*.
[155] *Id*.
[156] TGS Ex. 25 (Fairchild Rebuttal Test.) at 4.
[157] *Id*.
[158] *Id*. at 6.
[159] *Id*. at 6-7.
[160] TGS Ex. 16 (Fairchild Test.) at 5.

3. Cost of Equity

Cost of equity, or return on equity ("ROE"), is a major point of disagreement between TGS and all Intervenors. TGS proposes an ROE set at 10 percent. In support, TGS provides the following quantitative analyses to develop a cost of equity range of 9.5 percent to 10.5 percent: constant growth discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), risk premium method, and comparable earnings method.[161] TGS explained that despite the theoretical appeal of—or precedent for—using a particular method, no single approach is wholly reliable.[162] According to TGS, it is essential to compare the ROE estimates produced by one method with those produced by other methods and that all estimates pass fundamental tests of reasonableness and economic logic. [163]

TGS also reviewed the state of the natural gas industry and the variety of risks facing LDCs.[164] TGS argues that monetary policy normalization by the Federal Reserve (the "FED") implies higher capital costs.[165] TGS says it chose 10 percent—the middle of the range—to balance the forecasted higher capital costs and ONE Gas's relatively low financial risk compared to the proxy group.[166] According to TGS, a 10-percent ROE is at the bottom of the range of ROEs granted by the Commission to major LDCs over the last five years.[167] TGS's quantitative estimates are as follows: DCF—8.5 percent to 9.5 percent;[168] CAPM—9.4 percent to 10.46 percent;[169] risk premium—9.49 percent to 9.69 percent;[170] and Comparable Earnings—10.8 percent to 11.2 percent.[171] Together, TGS's estimates range from 8.5 percent to 11.2 percent.

Opposition by CEP and Coalition

In opposition, CEP proposes an ROE set at 9 percent based on CEP's proposed capital structure, or set at 8.45 percent if TGS's proposed capital structure is approved.[172] CEP provided the following quantitative analyses: DCF, two-stage DCF, CAPM, and risk premium.[173] CEP states that it considered current market conditions, TGS's riskiness, and TGS's financial integrity.[174] CEP's quantitative estimates are as follows: DCF—8.93 percent;[175] CAPM—9 percent;[176] and risk premium—9.2 percent.[177] According to CEP, TGS's proposed 10-percent ROE is overstated because it: (1) exceeds current capital market costs in light of low-debt costs and current equity returns being authorized by regulatory authorities; (2) exceeds capital market

[161] TGS Ex. 16 (Fairchild Test.) at 5.
[162] *Id*. at 22-23.
[163] *Id*.
[164] *Id*. at 6-9.
[165] *Id*. 9-12.
[166] *Id*. at 5.
[167] *Id*.
[168] *Id*. at 30.
[169] *Id*. at 35.
[170] *Id*. at 38.
[171] *Id*. at 38-39, Schedule BHF-11.
[172] CEP Ex. 1 (Lawton Direct Test.) 3:15-17 and 4:13-17.
[173] CEP Ex. 1 (Lawton Test.) at 9.
[174] *Id*. at 3, 18.
[175] *Id*. at 27.
[176] *Id*. at 31.
[177] *Id*. at 41.

costs for risk-comparable peer gas utility companies; and (3) fails to recognize the risk reducing attributes of the annual GRIP mechanism.[178]

CEP also disagreed with two aspects of TGS's quantitative analysis—size-adjustment for CAPM and incomplete comparable earning approach. Regarding the size adjustment, CEP says it found no studies in financial literature suggesting a size premium for gas utility operations.[179] CEP supports its argument with two studies from 1993 that specifically address utility stocks and size premium.[180] The studies conclude that while the size phenomenon has been strongly documented for industrials, there is no need to adjust the firm size in utility rate regulation and there are no risk differences between small and large utilities.[181] Regarding the comparable earnings approach, CEP argues that TGS ignored actual returns achieved in recent years and that TGS should have included actual equity returns for the recent 2013 to 2015 period, thus resulting in a range of 8.88 percent to 10.50 percent.[182] Regarding capital markets, CEP claims that current economic conditions do not warrant higher returns for utility companies and that the general economic data does not support increasing capital costs.[183]

CEP states that recent actions taken by the FED reflect a view of slightly weaker economic conditions than previously forecasted.[184] According to CEP, the current policy of extending low interest rates through the end of 2016 or longer, and the continuation of accommodative monetary policy, is viewed as an attempt to further increase economic growth to address general levels of unemployment and slow economic growth.[185] In support of its expectation of capital costs remaining low for the foreseeable future, CEP offers the conclusion from the Federal Reserve Federal Open Market Committee's April 2016 release, where the Committee concluded that the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the long run, and that economic conditions will evolve in a manner that warrants only gradual increases in the federal funds rate.[186]

In rebuttal, TGS maintains that a 10-percent ROE is reasonable. TGS states that the DCF underestimates the cost of equity and thus additional methods should be considered.[187] TGS defended its use of a size adjustment in the CAPM analysis and recommends that CEP's and Staff's results be corrected to include it.[188] TGS characterized the two studies cited by CEP as lesser-known, and that the effect of size on investors' required rates of return is well documented in financial literature, including "seminal research" by Nobel laureate Eugene F. Fama.[189] TGS defended its use of the comparable earnings method by explaining that referencing the expected returns—as opposed to historical returns—on book equity of other LDCs demonstrates the level of earnings TGS needs to offer investors a competitive return.[190] TGS opines that capital costs will be higher in the future and therefore choosing an ROE amongst the top of its range is

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[178] *Id*. at 40-41.
[179] *Id*. at 42.
[180] *Id*. at 40-41.
[181] *Id*. at 42.
[182] *Id*. at 43.
[183] *Id*. at 10, 13-14.
[184] *Id*. at 13.
[185] *Id*.
[186] *Id*. at 11.
[187] TGS Ex. 25 (Fairchild Rebuttal Test.) at 13-14.
[188] *Id*. at 18-19.
[189] *Id*. at 18.
[190] *Id*. at 24.

appropriate.[191] In response to CEP's criticism regarding the GRIP reducing risk, TGS explained that because of the widespread use of risk-reducing mechanisms, any reduced risk is already accounted for in the various cost of equity estimates.[192]

Opposition by Staff

Also in opposition, Staff proposes an ROE set at 9.25 percent. Staff's quantitative analysis consisted of two DCF models—30-day average stock price and 90-day average stock price—and CAPM. According to Staff, these two common cost-of-equity methods have been employed frequently in rate cases before the Commission.[193] Staff's quantitative estimates are as follows: 30-day DCF—9.37 percent, 90-day DCF—9.50 percent, and CAPM—8.93 percent.[194] Staff also considered the current capital market conditions and TGS's risk profile.[195]

Staff explained that TGS's proposed 10-percent ROE is predicated on the inclusion of results from suspect secondary estimation methods—risk premium and comparable earnings—and an unnecessary size premium adjustment to TGS's CAPM model. According to Staff, these methods have not been used in the final determination of an ROE in a rate case before the Commission.[196] Staff said the risk premium method has conceptual problems because it relies on past data to formulate a current result, which skews the results upward.[197] Staff explains that this method can only provide a rough estimate because it is prone to imprecision and distortion. According to Staff, isolating a recent range of the approved equity returns for the period from 2013 to 2015 is more reflective of current conditions and shows an average ROE of 9.66 percent.[198] Staff characterizes the risk premium method as "highly suspect" and of "limited value" in making an ROE determination.[199]

On the comparable earnings method, Staff states that this approach has "serious shortcomings" as a method for determining ROE and has never provided the basis for a Commission decision for rate of return.[200] According to Staff, the primary deficiency of the comparable earnings method is that it provides an accounting return on the expected book value of equity.[201] Therefore, Staff states this is not a market-based ROE, nor does it reflect the return available to investors, since an accounting return is not a market return, and utility stocks currently trade at percentages significantly higher than the book value of shares.[202] Staff emphasizes that the earned return on book equity is a different financial measure from the cost of equity, and therefore this method produces results that do not reflect capital market equity returns.[203] According to Staff, the comparable earnings approach has not been used in recent

[191] *Id*. at 23-24, 27.
[192] *Id*. at 24.
[193] Staff Ex. 1 (Tomicek Test.) at 4.
[194] *Id*. at 19.
[195] *Id*. at 4.
[196] *Id*. at 20.
[197] *Id*. at 27-28.
[198] *Id*. at 28.
[199] *Id*.
[200] *Id*. at 29.
[201] *Id*.
[202] *Id*.
[203] *Id*.

rate-setting proceedings and "appears to be largely discredited" in establishing an equity rate of return for regulated utilities.[204]

In rebuttal, TGS defended the size adjustment, explaining that within CAPM theory, most of a firm's unique risks are regarded as "non-systematic" and are eliminated through diversification. Thus, TGS states the only risk that matters is a firm's systematic risk, or how its returns move relative to the market as a whole.[205] According to TGS, because the CAPM assumes that investors are fully diversified, the impact of a firm's relative size on investors' required rate of return extends uniformly across all firms, and it applies to LDCs just as it does to every other firm.[206] TGS defends its risk premium approach, stating that: past ROEs are useful and the impact of outliers in data is minimized because TGS's risk premium analysis is based on over 1,000 ROE decisions; Staff's criticisms overlook the fundamental purpose and methodology of TGS's risk premium analysis, which is to use observable variables to estimate the cost of equity given *current* interest rates; and TGS's cost of equity estimates using a risk premium analysis do not materially differ from the ROEs presented by Staff.[207] TGS also defends its comparable earnings approach, stating that this approach is a useful and traditional method of evaluating a fair ROE, and it provides a direct guide to ensure that the allowed ROE is similar to that of other utilities of comparable risk.[208]

Examiner Findings and Recommendation

The Examiners find that the weight of the evidence does not support TGS's proposed 10-percent ROE. The Examiners recommend that ROE be set a 9.5 percent, which is just and reasonable and supported by the facts and evidence unique to this case.

i. The evidence does not support an ROE as high as 10 percent.

TGS, CEP, and Staff all presented DCF and CAPM analyses with different proxy groups, different time frames, and different methods. Of the several estimates, only one supported an ROE as high as 10 percent, and that was due to a size-adjustment premium of debated usefulness. TGS's ROE estimates ranged from 8.5 percent to 11.2 percent. Of the three quantitative analyses that the Examiners find valid—DCF, CAPM, and Risk Premium—the range's peak shrinks to 10.46 percent. The midpoint of this range is 9.48 percent. Only one estimate was as high as 10 percent. Accordingly, even by TGS's own estimates, a 10-percent ROE is not supported by the weight of quantitative evidence.

ii. The evidence supports that an ROE of 9.5 percent is reasonable.

Both Staff and TGS presented quantitative analyses supporting that an ROE estimate of 9.5 percent is reasonable. An ROE of 9.5-percent fits within the ranges of all three of TGS's quantitative analyses that the Examiners find valid—DCF, CAPM, and Risk Premium. An ROE of 9.5 percent also matches Staff's estimate when it used the mid-high average of the 90-day

[204] *Id*. at 30.
[205] TGS Ex. 25 (Fairchild Rebuttal Test.) at 21.
[206] *Id*. at 21-22.
[207] *Id*. at 22-23.
[208] *Id*. at 23.

stock price average DCF.[209] As stated above, mid-point of the range of ROE estimates is 9.48 percent, which further supports the reasonableness of an ROE set at 9.5 percent.

iii. An ROE of 9.5 percent is within the range of reasonable returns offered by TGS, and the evidence shows that a 9.5-percent ROE is unlikely to harm TGS in attracting capital.

TGS reasonably concluded that investors currently require a return on equity for LDCs in the range of 9.5 percent to 10.5 percent.[210] The evidence supports the reasonableness of this conclusion. Accordingly, a 9.5-percent ROE is unlikely to harm TGS in attracting capital.

iv. The evidence shows that capital market conditions warrant an ROE below 10 percent.

The evidence does not support TGS's assertion that capital costs will rise to a level that requires a 10-percent ROE. TGS's own updated projections show that the interest rates may not rise as high as projected. The evidence supports that setting an ROE in this case that is based on current capital market conditions, rather than speculating on future conditions, is reasonable. Accordingly, an ROE as high as 10-percent is not reasonable and not supported by the evidence for capital market conditions.

Conclusion

Considering the evidence, the Examiners find that an ROE of 9.5 percent is just and reasonable, supported by the facts and evidence unique to this case, and consistent with the requirements contained in GURA Chapter 104 (Rates and Services). Accordingly, the Examiners recommend that ROE be set at 9.5 percent.

4. Rate of Return Conclusion

Considering the evidence, The Examiners find a rate of return of 7.28 percent is just and reasonable, supported by the evidence, and will not yield more than a fair return on the adjusted value of the invested capital used and useful in providing service to the public. The Examiners recommend setting the rate of return at 7.28 percent, incorporating the below components.

Table 6: Examiners Recommended Rate of Return			
	Capital Structure	Cost	Weighted Average
Long-Term Debt	39.9%	3.95%	1.57%
Common Equity	60.1%	9.50%	5.71%
Rate of Return	**7.28%**		

The above recommended amounts are just and reasonable, supported by the evidence, and consistent with the requirements of GURA Section 104.052 (Establishing Fair Rate of Return) and Chapter 104 (Rates and Services).

[209] Staff Ex. 1 (Tomicek Test.) at 19.
[210] *See* TGS Ex. 16 (Fairchild Test.) at 5.

C. Operations and Maintenance Expenses

TGS requests expenses totaling to $53,585,960. The majority of TGS's requested operations and maintenance expenses are not challenged. Challenged expenses include: (1) depreciation, (2) incentive compensation, (3) pipeline integrity expenses, (4) base payroll, overtime expenses, and payroll taxes, (5) Supplemental Employee Retirement Plan ("SERP"), (6) injuries and damage expenses, and (7) Journey expenses.

As set out in detail below, the Examiners recommend a $3,082,860 reduction to TGS's requested expenses, reducing the total amount to $50,503,100.

1. Depreciation

Depreciation is a major point of disagreement between TGS and CEP. TGS requests approval of the same corporate and TGS division depreciation rates that were recently approved in GUD No. 10488 and approval of depreciation rates for WTSA assets based on a depreciation study that follows the same methodologies used in GUD No. 9988—TGS's last rate case involving the EPSA. TGS bases its requested depreciation rates on two 2015 depreciation studies conducted by Foster Associates Consultants, LLC ("Foster Associates"), an economic consulting firm. In support, TGS provided testimonial evidence from Ronald E. White (Ph.D., Engineering Valuation), President of Foster Associates.[211]

CEP recommends rejection of TGS's depreciation study and recommends that the existing depreciation rates be retained, and that the next study be specific to the EPSA or WTSA.[212] The three major depreciation issues raised are: TGS's treatment of a $24 million reserve imbalance for the EPSA that was approved in setting depreciation rates in GUD No. 9988, the appropriateness of the methods and execution of the TGS statewide study, and the amortization period for ONE Gas's Banner customer billing system software.[213] As an alternative to outright rejection of TGS's depreciation study, CEP alternatively recommends adjustments to the life parameters for seven accounts applicable to the EPSA and TGS Division, and adjustments to the net salvage values for three accounts.[214] In support, CEP provided testimonial evidence from Jacob Pous (M.S., Management), a registered professional engineer.[215]

Staff does not oppose TGS's depreciation study or the rates related to it.[216] Relating generally to compliance with applicable Texas law, Staff recommends that all depreciation rates—including Direct, Division, and Corporate depreciation rates—remain the same for any future Interim Rate Adjustment filings that might be made in reference to this docket, in compliance with Commission Rule 7.7101 (Interim Rate Adjustments) and Section 104.301 (Interim Adjustment for Changes in Investment) of the Texas Utilities Code.[217] In support, Staff

[211] TGS Ex. 15, Direct Testimony of Dr. Ronald E. White on Behalf of Texas Gas Service Company ("White Test."); TGS Ex. 24, Rebuttal Testimony of Dr. Ronald E. White on Behalf of Texas Gas Service Company ("White Rebuttal Test.").
[212] CEP Ex. 3, Direct Testimony of Jacob Pous on Behalf of The City of El Paso ("Pous Test."), at 9-20.
[213] *See id*. at 9-20 (reserve imbalance and statewide study), 20-26 (software amortization).
[214] *See id*. at 26-59.
[215] CEP Ex. 3 (Pous Test.).
[216] Staff Ex. 2 (Cromleigh Test.) at 23.
[217] *Id*. at 23-25 (citing 16 Tex. Admin. Code § 7.7101(f)(5) and Tex. Util. Code § 104.301(d)).

provided testimonial evidence from Erin Cromleigh, Financial Analyst in the Commission's Market Oversight Section of the Oversight and Safety Division.[218]

Current Depreciation Rates for the PSA, DCSA, and EPSA

Current depreciation rates for the PSA were approved by the cities of Andrews, Barstow, Crane, McCamey, Monahans, Pecos, Pyote, Thortonville, Wickett, and Wink pursuant to a rate application filed with those cities by TGS on September 30, 2008.[219] The approved rates are those derived and adopted for Pecos-Monahans in a study commissioned by Southern Union prior to June 30, 1985.[220] TGS does not know the source and content of the prior study.[221]

Current depreciation rates for the DCSA were approved by Dell City on February 8, 1993, and for DCSA environs by the Commission on July 26, 1993.[222] The approved rates are those adopted for Pecos-Monahans in 2008.[223]

Current depreciation rates for the EPSA and for all TGS service areas (the "TGS Division") were developed in a 2008 study, based on December 31, 2007 plant and reserve balances, conducted by Foster Associates.[224] Rates developed in the 2008 study were approved by the Commission in GUD No. 9988 on December 14, 2010.[225] Approved rates for the TGS Division were adopted for all TGS service areas.[226]

TGS's 2015 Depreciation Study

In support of its requested depreciation rates, TGS offers two 2015 depreciation studies: (1) for plant located in the newly defined WTSA, and for common facilities shared among all TGS service areas (the "TGS Study"), and (2) of corporate assets allocated to all TGS divisions (the "ONE Gas Study").[227] TGS offers that the depreciation methodologies contained in these studies are the same as those found reasonable by the Commission in GUD No. 9988 and recently used to calculate rates adopted in GUD No. 10488.[228] For simplicity herein and unless otherwise specified, the Examiners refer to the TGS Study and the ONE Gas Study jointly as the "2015 Depreciation Study."

The 2015 Depreciation Study uses a statistical analysis to calculate hazard rates, rather than visual curve fitting, and uses statewide retirement data, rather than WTSA-specific data.[229] Hazard rates were calculated from actual TGS plant data and retirements—they were not derived from visually matching TGS data to an Iowa curve, but rather were calculated based on actual

[218] Staff Ex. 2 (Cromleigh Test.).
[219] TGS Ex. 15 (White Test.) at 7-8.
[220] *Id*.
[221] *Id*.
[222] *Id*. at 8.
[223] *Id*.
[224] *Id*.
[225] *Id*.
[226] *Id*.
[227] *Id*. at 3-17; *see also id.* at Attachments REW-2 (TGS Study) and REW-3 (ONE Gas Study).
[228] TGS Ex. 24 (White Rebuttal Test.) at 2.
[229] TGS Ex. 15 (White Test.) at Attachment REW-2 (TGS Study), pp. 9-11; TGS Ex. 24 (White Rebuttal Test.) at 4-6.

retirement data.[230] According to TGS, the use of statewide retirement data, rather than WTSA-specific data, provides a larger sample size and thus more accurately reflects retirement experience in the WTSA, even taking into consideration differences in geography.[231] The 2015 Depreciation Study retains the same depreciation system used in TGS's 2008 studies for all jurisdictions.[232]

Below is a summary of TGS's proposed changes in annual rates and accruals resulting from the parameters and depreciation rates recommended for the WTSA.

Table 7 - West Texas Service Area

	Accrual Rate			2015 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	1.80%	2.35%	0.55%	$ 533,167	$ 693,609	$ 160,442
Distribution	1.90%	2.37%	0.47%	5,739,056	7,179,691	1,440,636
General Plant	7.28%	7.06%	-0.22%	1,346,730	1,305,930	(40,000)
Total	2.17%	2.62%	0.45%	$7,618,953	$9,179,230	$1,560,277

TGS recommends primary account depreciation rates equivalent to a composite rate of 2.62 percent.[233] Depreciation expense currently is accrued at rates that composited to 2.17 percent.[234] The recommended change in the composite depreciation rate is an increase of 0.45 percentage points. A continued application of current rates would provide annualized depreciation expense of $7,618,953, compared with an annualized expense of $9,179,230 using the rates developed in the TGS Study.[235] The expense increase is $1,560,277.

Below is a summary of TGS's proposed changes in annual rates and accruals resulting from the parameters and depreciation rates recommended for the TGS Division.

Table 8 - TGS Division

	Accrual Rate			2015 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant	12.13%	12.15%	0.02%	$1,097,981	$1,099,882	$ 1,901
Total	12.13%	12.15%	0.02%	$1,097,981	$1,099,882	$ 1,901

TGS recommends primary account depreciation rates equivalent to a composite rate of 12.15 percent.[236] Depreciation expense currently is accrued at rates that composite to 12.13 percent.[237]

[230] TGS Ex. 15 (White Test.) at Attachment REW-2 (TGS Study), pp. 9-11; TGS Ex. 24 (White Rebuttal Test.) at 16.
[231] TGS Ex. 24 (White Rebuttal Test.) at 4-7.
[232] TGS Ex. 15 (White Test.) at 13.
[233] *Id*. at 14.
[234] *Id*.
[235] *Id*.
[236] *Id*. at 16.

The recommended change in the composite depreciation rate is an increase of 0.02 percentage points. A continued application of current rates would provide annualized depreciation expense of $1,097,981, compared with an annualized expense of $1,099,882 using the rates developed in the TGS Study.[238] The expense increase is $1,901.

Below is a summary of TGS's proposed changes in annual rates and accruals recommended for ONE Gas corporate assets.

Table 9 - ONE Gas

	Accrual Rate			2015 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant						
Depreciable	5.94%	6.93%	0.99%	$ 962,542	$ 1,122,230	$ 159,688
Amortizable	7.40%	8.05%	0.65%	8,165,832	8,874,250	708,418
Total	7.22%	7.90%	0.68%	$9,128,374	$9,996,480	$ 868,106

The ONE Gas Study produces primary account depreciation rates equivalent to a composite rate of 7.90 percent.[239] Current accrual rates composite to 7.22 percent.[240] The change in the composite depreciation rate is an increase of 0.68 percentage points. A continued application of current rates would provide annualized depreciation expense of $9,128,374, compared with an annualized expense of $9,996,480 using the rates in the ONE Gas Study.[241] The increase in 2015 expense is $868,106, of which only a portion will be allocated to TGS.[242]

Opposition by CEP and Coalition

<u>CEP's Primary Recommendation</u>

CEP's primary recommendation is that the Commission wholly reject TGS's 2015 Depreciation Study and instruct TGS to provide a new study which (1) fully and specifically explains and justifies the major life and net salvage parameters based on the EPSA or the WTSA, and (2) documents and demonstrates the exhaustion of the $24 million surplus reserve which, according to CEP, has not been returned to EPSA customers.[243] The three major depreciation issues are: (*i*) TGS's treatment of a $24 million reserve imbalance for the EPSA that was approved in setting depreciation rates in GUD No. 9988, (*ii*) the appropriateness of the methods and execution of TGS's statewide study, and (*iii*) the amortization period for ONE Gas's Banner customer billing system software.[244]

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[237] *Id*.
[238] *Id*.
[239] *Id*. at 17.
[240] *Id*.
[241] *Id*.
[242] *Id*.
[243] CEP Ex. 3 (Pous Test.) at 9-20.
[244] *Id*. at 9-20 (reserve imbalance and statewide study), 20-26 (software amortization).

i. Reserve Imbalance

CEP and Coalition argue that TGS cannot account—or has refused to account—for a $24 million reserve imbalance that, according to CEP and Coalition of Cities, is owed specifically to EPSA customers. In GUD No. 9988, TGS's last rate case involving the EPSA, the Commission approved TGS's proposal to amortize a $24 million reserve imbalance "over the remaining lives of the assets."[245] In the 2015 Depreciation Study, this $24 million amounts to approximately $221,665 for the EPSA.[246] According to CEP, customers and the Commission are entitled to a full showing and explanation as to how and why this $24 million reserve imbalance has "inexplicably disappeared" over a very short period rather than the approximately 40-year period discussed in GUD No. 9988.[247] CEP and Coalition maintain that TGS has failed—and continues to fail—to clearly explain and justify TGS's handling of this $24 million reserve imbalance.[248]

In response, TGS explains that TGS's plant investment has roughly doubled since TGS's last rate case, and accordingly, the reserve imbalance did not "disappear," but rather has been offset by incremental investments made since rates were last set.[249] According to TGS, plant balances and computed reserve increased significantly since GUD No. 9988 by 45 percent and 46 percent, respectively, and that far exceeded the relatively small 15 percent increases to recorded reserves.[250] TGS notes that CEP does not challenge the significant incremental investment made to plant assets since GUD No. 9988, and TGS maintains that it correctly calculated the reserve balance.[251] Furthermore, TGS asserts that the $24 million reserve imbalance for the EPSA in GUD No. 9988 does not affect the other service areas in the WTSA.[252] According to TGS, each service area in the WTSA has its own recorded and computed reserves that were used to calculate reserve imbalances for each area.[253] The $24 million imbalance identified in GUD No. 9988 and the diminution of that imbalance to roughly $221,000 are specific to the EPSA, and no other service area is affected by the changes to the reserve because redistributions were performed on a service area-specific basis.[254] Contrary to CEP's claims, TGS states that it provided to CEP every calculation and data point necessary to calculate the proposed depreciation rates and offered to allow CEP to review the software used to calculate the rates.[255]

ii. TGS's Use of a Statewide Study

CEP argues that the 2015 Depreciation Study is flawed because it inappropriately and unnecessarily commingles statewide data from all nine TGS service areas, rather than solely

[245] GUD 9988 Final Order, signed Dec. 14, 2010, Finding of Fact 25 ("TGS proposes amortizing reserve imbalance over the remaining lives of the assets. This approach is reasonable and in accordance with rate-making principles.").
[246] CEP Ex. 3 (Pous Test.) at 10; *see also* TGS Ex. 15 (White Test.) at Attachment REW-2 (TGS Study), p. 28 (recorded reserve 77,902,892 less computed reserve 77,681,227 = 221,665).
[247] CEP Ex. 3 (Pous Test.) at 10.
[248] CEP Initial Br. at 29-31; Coalition Initial Br. at 6.
[249] *See* TGS Ex. 24 (White Rebuttal Test.) at 3 (plant increased from $175 million to $325 million); Tr. at 86-87 (July 20, 2016) (White testifying).
[250] TGS Ex. 24 (White Rebuttal Test.) at 3; *see also* Tr. at 66-67 (July 20, 2016) (White testifying).
[251] TGS Reply Br. at 19-20.
[252] TGS Initial Br. at 30.
[253] *See* CEP Ex. 11 (TGS Response to RFI 12-10).
[254] *See* TGS Ex. 15 (White Test.) at Attachment REW-2 (TGS Study), pp. 27-30.
[255] *See* TGS Ex. 27 (TGS Supplemental Response to CEP RFI 1-11); *see also* TGS Reply Br. at 18.

using data from the EPSA or WTSA. In support, CEP offers that data from the EPSA alone is sufficient to conduct a depreciation study, and doing so would be more accurate due to the varied life characteristics between coastal environments and the EPSA, along with other differences between TGS service areas.[256]

In response, TGS argues that its use of statewide data is reasonable, necessary, and consistent with the manner in which depreciation rates were calculated in GUD No. 9988. TGS maintains that a larger sample of statewide data more accurately reflects retirement experience in the WTSA, even taking into consideration differences in geography, by allowing TGS's depreciation expert to study 54 activity years of statewide retirements compared to just 16 available years of data for the EPSA and PSA, or four years for the DCSA.[257] According to TGS, the larger sample size provides TGS a higher degree of confidence in the results.[258] TGS also points out that statewide data has been used in every depreciation study conducted for TGS since 2002.[259]

iii. ONE Gas's Banner Software Amortization

ONE Gas's Banner software system is the company's customer information and billing system. TGS proposes an amortization period of 13 years for Account 391.60 (Purchased Software), which includes the Banner software.[260] CEP argues that the proposed amortization rate for the Banner software will allow TGS to over-recover its investment once this account is fully accrued.[261] CEP estimates that the Banner system will be fully recovered by July 2018—approximately one and a half years after rates in this proceeding become effective—yet the "expected timing" of TGS's next base rate proceeding won't occur until 2023, and so an extension of the amortization period through 2023 is necessary to prevent a "gross over recovery" from TGS customers for the investment in the Banner system.[262]

In response, TGS maintains that a 13-year amortization period is reasonable for these assets and TGS will not over-recover its investment in the software system.[263] As explained in the ONE Gas Study, a 13-year amortization period falls "will within a zone of reasonableness," and this specific period length was selected with consideration for the "potential impact of shifting reserves from the depreciable categories into the amortizable categories."[264] According to TGS, CEP's arguments and concerns are unfounded because: purchased software assets include much more than Banner software, and these other software also are impacted by the amortization period for this account; CEP fails to account for software upgrades and replacements; and it is unreasonable to try to time accruals of software to projected future regulatory filings.[265] TGS states that if this asset fully accrues before the next base rate

[256] CEP Ex. 3 (Pous Test.) at 9-15.
[257] TGS Ex. 24 (White Rebuttal Test.) at 4-7; Tr. at 83 (July 20, 2016) (White testifying).
[258] TGS Ex. 24 (White Rebuttal Test.) at 4-5.
[259] TGS Ex. 27 (Deposition of Ronald E. White transcript) at 95-97; *see also* TGS Br. at 29.
[260] TGS Ex. 15 (White Test.) at Attachment REW-3 (ONE Gas Study), p. 4.
[261] *See* CEP Ex. 3 (Pous Test.) at 20-26.
[262] *Id*. at 24-26.
[263] TGS Ex. 20 (Buchanan Rebuttal Test.) at 9.
[264] TGS Ex. 15 (White Test.) at Attachment REW-3 (ONE Gas Study), p. 4.
[265] TGS Reply Br. at 21.

proceeding, then TGS will remove the fully accrued balance from its depreciation expense in its next Interim Rate Adjustment filing, just as it did in past rate cases.[266]

TGS further notes that its proposed depreciation rates for ONE Gas recently were approved by the Commission in GUD No. 10488.[267] According to TGS, it would be difficult, if not impossible, for ONE Gas to now use different depreciation rates for the same corporate plant allocated to each jurisdiction.[268] According to TGS, this would require ONE Gas to assign a fraction of each asset to each service area or jurisdiction and maintain different corporate accrual rates and reserves for inseparable items of plant and equipment equally benefiting customers in all service areas.[269]

<u>CEP's Alternative Recommendations</u>

As an alternative to outright rejection of TGS's 2015 Depreciation Study, CEP alternatively recommends adjustments to the life parameters for seven (7) accounts, and adjustments to the net salvage values for three (3) accounts.[270] According to CEP, TGS does not adequately show the basis for TGS's proposed life parameters, instead providing only conclusions without providing meaningful specifics as to how the actual results are obtained. Accordingly, CEP argues that the Commission should reject TGS's approach with respect to these specific accounts and instead adopt CEP's visual curve-fitting approach, which, according to CEP, is more attuned to industry standard.[271]

In response, TGS argues that CEP's proposed alternative adjustments to these accounts are based on unsupported assumptions and generalizations, as well as the speculative "informed judgment" of CEP's depreciation expert.[272] According to TGS, CEP does not explain how any of CEP's alternative adjustments translate to a quantifiable lengthening of dollar-years of service, which, according to TGS's depreciation expert, is a more accurate metric for depreciation purposes than simply lengthening a service life.[273] TGS states that it made only minor adjustments to the service lives approved previously in GUD No. 9988, and all adjustments were supported by TGS data and the 2015 Depreciation Study.[274]

Furthermore, TGS states that, contrary to CEP's argument, it is virtually impossible to estimate the service life of physical property with the level of precision implied in CEP's alternative recommended adjustments.[275] Also, TGS contends that CEP's recommended adjustment calculations are inherently flawed and should be disregarded because CEP improperly used rebalanced reserves derived from the parameters and computed reserves of TGS

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[266] TGS Ex. 20 (Buchanan Rebuttal Test.) at 9 ("The Company has removed fully accrued plant from Interim Rate Adjustment filings for the El Paso Service Area in GUD Nos. 10270, 10347, and 10436.").
[267] TGS Ex. 24 (White Rebuttal Test.) at 21-22.
[268] *Id*. at 22.
[269] *Id*.
[270] *See* CEP Ex. 3 (Pous Test.) at 26-59.
[271] *See id*. at 26-31.
[272] TGS Ex. 24 (White Rebuttal Test.) at 12.
[273] *Id*. at 12-13.
[274] *See* TGS Ex. 15 (White Test.), Attachment REW-2 (TGS Study), pp. 9-13, 36; *see also* TGS Reply Br. at 22.
[275] TGS Ex. 24 (White Rebuttal Test.) at 16.

rather than CEP's own calculation of rebalanced reserves derived from CEP's parameters and calculations.[276]

Seven (7) Life Parameter Accounts

CEP's recommended adjustments to seven (7) life parameter accounts are summarized below:

Table 10 – CEP Life Adjustments

FERC Acct. No.	Account Title	Existing Service Life	TGS Proposed Service Life	CEP Proposed Service Life
367	Transmission Mains	60 yrs	60 yrs	66 yrs
376	Distribution Mains	65 yrs	65 yrs	70 yrs
376.90	Distribution Mains – Cathodic Protection Anodes	n/a	15 yrs	19 yrs (if separation from Account 376 is allowed)
380	Distribution Services	55 yrs	55 yrs	59 yrs
381	Distribution Meters	28 yrs	25 yrs	27 yrs
391.90	Computers and Electronic Equipment	7-year amortization	7-year amortization	10-year amortization
392	Transportation Equipment	8 yrs	10 yrs	13 yrs

- *Account 367 (Transmission Mains).* TGS proposes to retain the 60-year projection life approved in GUD No. 9988. CEP recommends lengthening this projected life to 66 years, arguing that TGS has not demonstrated that a life as short as 60 years for transmission mains is reasonable.[277] According to CEP, the "industry standard" visual curve fitting approach results in a longer life indication than TGS's proposed 60-year value or even CEP's recommended 66-year value.[278] CEP also argues that TGS ignored important considerations, such as the young age of the transmission mains in the El Paso area, the likely benefit from a recent implementation of a pipeline integrity and inspection program, and certain "unusual retirement activities."[279]

  In response, TGS argues that CEP relied on generalizations and failed to justify CEP's recommended 6-year lengthening of the projection life with step-by-step explanation or quantification.[280] TGS also argues that CEP failed to appropriately rank and weigh considered factors, and failed to provide any evidence that CEP's

[276] *Id*. at 20.
[277] CEP Ex. 3 (Pous Test.) at 31-35.
[278] *Id*. at 32-34.
[279] *Id*. at 34-35.
[280] TGS Ex. 24 (White Rebuttal Test.) at 15.

recommendations are superior to TGS's.[281] According to TGS, maintaining the existing 60-year life curved approved in GUD No. 9988 is reasonable and supported by the 2015 Depreciation Study.[282]

- *Account 376 (Distribution Mains)*. TGS proposes to retain the 65-year projection life approved in GUD No. 9988. CEP recommends lengthening this projected life to 70 years, arguing that TGS understates the service life, in part, by failing to account for improved manufacturing, installation, and maintenance practices in the industry.[283]

  In response, TGS argues that CEP's recommendation is speculative and unjustified.[284] TGS points out that its proposed 65-year projection life was approved in GUD No. 9988 and maintains that a 65-year projection life is appropriate. According to TGS, it could find no evidence that forces of retirement have changed since the 2008 depreciation study or operational changes have or will occur that might extend the currently-approved 65-year projection life for this account.[285]

- *Account 376.90 (Distribution Mains – Cathodic Protection Anodes)*. TGS proposes a 15-year amortization period consistent with the period adopted in GUD No. 10488. TGS recommends segregating cathodic protection assets from Account 376 (Distribution Mains) and applying a 15-year amortization period. CEP recommends retention of a single account, arguing that there is no need to create a different subaccount since "all accounts have within them different components with different lives for such components," and that TGS instead should perform and present "a full, meaningful and well supported deprecation study rather than branching out into unwarranted and nonstandard subcategory components."[286] In the alternative, if separation is allowed, CEP recommends extending this period to 19 years, arguing that TGS's proposed consumption rate is unsupported and too "aggressive."[287]

  In response, TGS states that CEP ignores that anodes are currently systematically retired at an age of 12 years, which supports reclassifying anodes to a subaccount and amortizing these assets over a 15 years—a period approved in GUD No. 10488.[288] At the Hearing, TGS's depreciation expert testified that TGS's proposed separation of cathodic protection assets into a subaccount is consistent with TGS's practices in other jurisdictions and is consistent with what was done in GUD No. 10488.[289]

- *Account 380 (Distribution Services)*. TGS proposes a 55-year projection life, consistent with the existing life-curve approved in GUD No. 9988. CEP recommends lengthening this service life to 59 years, arguing that TGS presented no basis for its proposed 55-year service life.[290] According to CEP, a longer life expectancy is

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281 *Id*.
282 *Id*.; *see also* TGS Ex. 15 (White Test.) at Attachment REW-2 (TGS Study), p. 36.
283 *See* CEP Ex. 3 (Pous Test.) at 36-40.
284 TGS Ex. 24 (White Rebuttal Test.) at 15-16.
285 *Id*.
286 CEP Ex. 3 (Pous Test.) at 40-41.
287 *Id*.
288 TGS Ex. 24 (White Rebuttal Test.) at 16.
289 Tr. at 70 (July 20, 2016) (White testifying).
290 CEP Ex. 3 (Pous Test.) at 41-44.

warranted because TGS's mathematical curve-fitting process is "inappropriately and significantly skewed" to capture insignificant hazard rates and because the historical data relied upon by TGS does not reflect technological improvements in the quality and installation of plastic services.[291] Furthermore, CEP argues that TGS, in its mathematical approach, failed to consider the unrealistic influence by hazard rates after the meaningful or significant portion of the observed life table. CEP also notes that TGS identifies a 61-year life-curve combination as the most appropriate second degree orthogonal polynomial result. [292]

In response, TGS maintains that its proposed 55-year projection life is appropriate and supported by the 2015 Depreciation Study.[293] According to TGS, CEP fails to explain how advanced technology and better quality plastics translates to a 4-year extension of the 55-year projection life, nor does CEP provide a ranking of all factors considered with a relative weight applied to each factor.[294]

- *Account 381 (Distribution Meters)*. TGS proposes a reduction of the existing service life from 28 years to 25 years. CEP recommends a service life of 27 years, arguing that TGS's proposal reflects too great a decrease.[295] According to CEP, TGS gave improper weighting to certain historical data points and "presented no information which warrants" a 25-year service life.[296]

  In response, TGS maintains that its proposed 25-year service life is appropriate, arguing that it is virtually impossible to estimate the service life of physical property with the level of precision CEP implies with its adjustments.[297] According to TGS, a 2-year extension of 25-year projection life cannot be defended from CEP's visual curve fitting and is mere speculation by CEP about the impact of non-quantitative factors.[298]

- *Account 391.90 (Computers and Electronic Equipment)*. TGS proposes maintaining the existing 7-year amortization period approved in GUD No. 9988. CEP recommends lengthening this service life to 10 years, arguing that TGS provides no "narrative explanation" for its decision to retain the existing 7-year amortization.[299] CEP notes that, along with keeping the 7-year amortization for this account, TGS also proposes increasing the amortization rate from 11.05 percent to 13.36 percent.[300] According to CEP, this account contains investment with varied service lives ranging from 3-5 years (laptops/PCs) to 10-20 years (software investments).[301] Segregating

[291] *Id*. at 42-44.
[292] *Id*. at 42-43.
[293] TGS Ex. 24 (White Rebuttal Test.) at 16.
[294] *Id*.
[295] CEP Ex. 3 (Pous Test.) at 45-48.
[296] *Id*.
[297] TGS Ex. 24 (White Rebuttal Test.) at 16-17.
[298] *Id*.
[299] CEP Ex. 3 (Pous Test.) at 48-50.
[300] *Id*. at 48.
[301] *Id*. at 49.

the investment into identifiable categories, CEP argues, yields a 10-year weighted useful life.[302]

In response, TGS maintains that a 7-year amortization period is reasonable, explaining that the difference in amortization rates identified by CEP is attributable to the size and number of vintages to be retired during the study year.[303] According to TGS, there is no basis to deviate from the 7-year amortization period approved in GUD No. 9988.[304] Furthermore, TGS states that CEP incorrectly incorporated CEP's recommended adjustment to the amortization period for this account.[305] According to TGS, CEP failed to recognize the necessity to transfer reserves from all service areas into the TGS Division, and this CEP oversight results in incorrect calculations.[306]

- *Account 392 (Transportation Equipment).* TGS proposes a 10-year life projection. CEP recommends lengthening this service life to 13 years, arguing that TGS's proposed life for this account is "a step in the right direction" but remains artificially short and unsupported.[307] According to CEP, a 13-year life projection is supported by visual curve fitting.[308] CEP argues that TGS relied too heavily on the large level of retirements at early ages—which CEP offers is most likely associated with accidents—and that TGS's vehicle fleet is mostly pickup trucks, heavier trucks, and trailers, which CEP offers have relatively long useful lives.[309]

  In response, TGS maintains that its proposed 10-year service life is appropriate, arguing that it is virtually impossible to estimate the service life of physical property with the level of precision CEP implies with its adjustments.[310] According to TGS, a 3-year extension of 10-year projection life cannot be defended from CEP's visual curve fitting and is mere speculation by CEP about the impact of non-quantitative factors.[311]

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302 *Id*.
303 TGS Ex. 24 (White Rebuttal Test.) at 17.
304 *Id*.
305 *Id*. at 21.
306 *Id*.
307 CEP Ex. 3 (Pous Test.) at 50-53.
308 *Id*. at 52.
309 *Id*. at 52-53.
310 TGS Ex. 24 (White Rebuttal Test.) at 16-17.
311 *Id*.

Three (3) Net Salvage Values

CEP's recommended adjustments to three (3) net salvage values for certain accounts are summarized below:

Table 11 – CEP Net Salvage Adjustments

FERC Acct. No.	Account Title	Net Salvage Existing	Net Salvage TGS Proposed	Net Salvage CEP Proposed
367	Transmission Mains	-10%	-30%	-10%
381	Distribution Meters	0%	-10%	-5%
392	Transportation Equipment	5%	5%	15%

- *Account 367 (Transportation Mains)*. TGS proposes a negative 30 percent net salvage. CEP recommends retention of the existing negative 10 percent net salvage value, arguing that TGS provided no explanation or "specific narrative" for the change.[312] According to CEP, TGS's historical data is both unstable and unreliable as a basis for predicting future values, and the existing negative 10 percent value should be retained pending the results of a removal cost study for the assets in this account.[313]

  In response, TGS states that CEP failed to explain why negative 30 percent is an unreasonable ratio.[314] According to TGS, the recommended negative 30 percent net salvage rate is based on TGS's depreciation expert's analysis of realized net salvage and his judgment that removal costs will continue to increase.[315]

- *Account 381 (Distribution Meters)*. TGS proposes a negative 10 percent net salvage. CEP recommends a movement to no greater than a negative 5 percent net salvage value, arguing that TGS provides "no specific narrative" for the development of a negative 10 percent net salvage.[316] According to CEP, any movement to a value greater than negative 5 percent would not be indicative of the change in overall net salvage as recorded between TGS's 2008 and 2015 depreciation studies.[317] CEP points out that TGS's proposed value is two and a half times the level of change since TGS's last 2008 depreciation study.[318]

  In response, TGS argues that its negative 10 percent value is reasonable because labor charges to remove and replace metering equipment—as a percent of the installed cost of meters retired—averaged negative 20 percent from 2004 to 2008.[319]

[312] CEP Ex. 3 (Pous Test.) at 54-55.
[313] *Id*.
[314] TGS Ex. 24 (White Rebuttal Test.) at 18.
[315] *Id*.
[316] CEP Ex. 3 (Pous Test.) at 55-57.
[317] *Id*. at 56.
[318] *Id*.
[319] TGS Ex. 24 (White Rebuttal Test.) at 18-19.

- *Account 392 (Transportation Equipment).* TGS proposes a 5 percent net salvage. CEP recommends a 15 percent positive net salvage, arguing that TGS's basis for its proposed value is unknown.[320] According to CEP, the 5 percent value proposed by TGS is artificially low, and a 10-23 percent positive net salvage is realistic "based on the used vehicle market for pickup trucks in the El Paso and other western Texas areas."[321]

  In response, TGS explains the basis for its proposed 5 percent net salvage rate: (a) from the mid-1990s through 2009, the majority of TGS's transportation equipment was leased; (b) a buyout of the leased equipment occurred in 2009 and the acquisition cost of the vehicles was recorded at the lease buyout price, which was less than the original cost of the vehicles; (c) the ratio of salvage proceeds to a buyout price was accordingly higher than the ratio of salvage proceeds to original costs; (d) the salvage value of vehicles sold at auction currently averages about $3,000 for vehicles with over 150,000 miles; and (e) the salvage value of the fleet of owned vehicles as a percent of acquisition costs will continue to decline as vehicles acquired through the lease buyout are replaced with vehicles acquired at original cost.[322] TGS argues that the 10-23 percent salvage value of used vehicles offered by CEP is unrealistic and unsupported.[323]

Examiner Findings and Recommendation

The Commission shall establish proper and adequate rates and methods of depreciation, amortization, or depletion for each class of property of a gas utility.[324] Considering the evidence, the Examiners find that TGS's proposed rates and methods of depreciation, amortization, and depletion are proper and adequate, and just and reasonable, and supported by the evidence, with certain exceptions. CEP's and Coalition's arguments were persuasive and well-argued, but ultimately the weight of the evidence did not support wholly discarding TGS's depreciation studies. The Commission previously found the same methodologies used in these studies to be just and reasonable in GUD No. 9988—TGS's last rate case involving the EPSA. In this docket, the evidentiary record contains two depreciation studies—the TGS Study and the ONE Gas Study—along with persuasive and credible testimony from TGS's depreciation expert, all supporting TGS's proposed depreciation rates. Except for the three account adjustments described below, TGS's proposed depreciation rates were sufficiently explained and supported by TGS's evidence, and the Examiners find these rates to be proper and adequate—and just and reasonable.

<u>Reserve Imbalance</u>

With respect to concerns by CEP and Coalition about the reduction of the EPSA reserve imbalance from $24 million to approximately $221,665, TGS sufficiently accounts for this decrease. TGS showed an approximate $150 million increase in the EPSA plant since the last

[320] CEP Ex. 3 (Pous Test.) at 57-58.
[321] *Id*. at 58.
[322] TGS Ex. 24 (White Rebuttal Test.) at 19.
[323] *Id*.
[324] Tex. Util. Code § 104.054 (Depreciation, Amortization, and Depletion).

rate case, with computed reserves increasing by approximately 46 percent and the recorded reserves only increasing by approximately 15 percent.[325] The evidence shows that TGS's assets in the EPSA have increased substantially, and that this reserve imbalance has been applied to the lives of these assets. The evidence does not support that this reserve imbalance "vanished" or "disappeared" or else was handled improperly by TGS.

TGS's Use of a Statewide Study

With respect to TGS's use of statewide data in its 2015 depreciation studies, TGS sufficiently demonstrated a cognizable rationale for using statewide data—that a larger sample size provides a higher degree of confidence in the results—and supported this rationale with credible evidence. CEP's view that an alternate depreciation study using only EPSA- or WTSA-specific data would be possible—and perhaps even better—does not by itself negate the utility and reasonableness of TGS's decision to use statewide data in its 2015 Depreciation Study. The evidence does not support that it was unreasonable for TGS to do so.

ONE Gas's Banner Software Amortization

With respect to the amortization period for ONE Gas's Banner customer billing system software, the weight of the evidence does not support CEP's recommendation to extend the TGS's proposed amortization period. While CEP generally argues that TGS's 13-year amortization period for this software is insufficient, its main concern is that TGS will over-recover from its customers if the Banner system is fully recovered several years before TGS's next full rate proceeding. TGS sufficiently addressed this concern by showing that if this asset fully accrues before the next base rate proceeding, then TGS will remove the fully accrued balance from its depreciation expense in its next Interim Rate Adjustment filing, just as it did in past rate cases. This sufficiently protects against over-recovery by TGS from its customers and avoids speculating on the dates and nature of future rate-change requests by TGS.

CEP's Alternative Recommendations

The weight of the evidence does not support TGS's proposed life parameters for Account 391.90 (Computers and Electronic Equipment) or Account 380 (Distribution Services), or TGS's proposed net salvage value for Account 367 (Transportation Mains).

For Account 391.90 (Computers and Electronic Equipment), the credible evidence shows that this account contains investment with varied service lives ranging from 3-5 years (laptops/PCs) to 10-20 years (software investments). The Examiners find that TGS's proposed 7-year amortization period is not proper and instead recommend using a 10-year period recommended by CEP. For Account 380 (Distribution Services), the credible evidence shows that a life expectation longer than TGS's proposed 55 years is appropriate. The Examiners find that TGS's proposed 55-year service life is not proper and instead recommend using a 59-year period recommended by CEP. For Account 367 (Transportation Mains), the weight of credible evidence does not support changing the net salvage value from the existing negative 10 percent. While TGS argues that CEP failed to explain why negative 30 percent is an unreasonable ratio, CEP did not have to. TGS, not CEP, carries the burden of proving why its proposed negative 30

[325] *See* TGS Ex. 24 (White Rebuttal Test.) at 3; Tr. at 66-68 (July 20, 2016) (White testifying).

percent value is reasonable and it failed to do so. The Examiners find that TGS's proposed negative 30 percent net salvage value is not proper and instead recommend using a negative 10 value recommended by CEP.

With respect to TGS's proposed adjustments and values for all other accounts, the weight of the evidence supports TGS's proposals. For these other accounts, the Examiners find that TGS's proposed service lives and values are supported by credible evidence, and are proper and adequate—and just and reasonable.

Conclusion

Except for TGS's proposed life parameters for Account 391.90 (Computers and Electronic Equipment) and Account 380 (Distribution Services), and TGS's proposed net salvage value for Account 367 (Transportation Mains), TGS's proposed depreciation rates are proper and adequate, just and reasonable, supported by the evidence, and meet the requirements of GURA Section 104.054 (Depreciation, Amortization, and Depletion) and Chapter 104 (Rates and Services). The Examiners recommend their approval.

CEP's recommended 10-year amortization period for Account 391.90 (Computers and Electronic Equipment), 59-year service life for Account 380 (Distribution Services), and negative 10 percent net salvage value for Account 367 (Transportation Mains) are proper and adequate, just and reasonable, supported by the evidence, and meet the requirements of GURA Section 104.054 (Depreciation, Amortization, and Depletion) and Chapter 104 (Rates and Services). The Examiners recommend the approval of the depreciation rates as shown in attached schedules WKP G-15.a.1 (direct), WKP G-15.b.1 (division), and WKP G-15.c.1 (corporate).

2. Incentive Compensation

Incentive compensation is a major point of disagreement between TGS and CEP/Coalition. TGS requests recovery of all of its actual, test-year incentive compensation costs, which total $2,827,357 for both short-term incentive ("STI") and long-term incentive ("LTI") plans. In support, TGS provided testimonial evidence from: Caron A. Lawhorn, Senior Vice President, Commercial, for ONE Gas;[326] Allison Edwards, Rates Analyst for ONE Gas;[327] and Anna Kern, Compensation Manager within the Human Resources Department for ONE Gas.[328]

Staff does not oppose TGS's requested recovery of incentive compensation.

[326] TGS Ex. 5 (Lawhorn Test.); TGS Ex. 18 (Lawhorn Rebuttal Test.).

[327] TGS Ex. 9, Direct Testimony of Allison Edwards on Behalf of Texas Gas Service Company ("Edwards Test."); TGS Ex. 21, Rebuttal Testimony of Allison Edwards on Behalf of Texas Gas Service Company ("Edwards Rebuttal Test.").

[328] TGS Ex. 11, Direct Testimony of Anna Kern on Behalf of Texas Gas Service Company ("Kern Test."); TGS Ex. 22, Rebuttal Testimony of Anna Kern on Behalf of Texas Gas Service Company ("Kern Rebuttal Test.").

Incentive Compensation – Generally

TGS offers that, as a 100 percent regulated gas utility, all compensation dollars paid to its employees—whether salary or incentive—are directed solely towards regulated gas utility work and therefore should be recognized if they are within market norms.[329] According to TGS, compensating employees based solely on salary or base pay is an outdated practice that would place TGS at a competitive disadvantage.[330] TGS views compensation as a comprehensive package, which includes both base pay and incentive compensation, and that the level is generally at or below comparable energy company industry levels.[331] In partial support of its request, TGS offered six prior dockets where the Commission approved the recovery of incentive compensation:

Table 12 – Incentive Compensation Past Decisions

GUD No.	Short-Term	Long-Term
10170	Partial	Partial
10000	Partial	Partial
9902	All	All
9869	Partial	Partial
9791	Partial	Partial
9762	Partial	Partial

Short-Term Incentive (STI)

TGS requests a total STI amount of $2,229,854. According to TGS, the STI plan is variable pay based on employee and TGS performance, and is designed to motivate employees to operate safely and efficiently.[332] TGS states that its STI is determined, in part, by a company performance factor based on diluted annual earnings per share, total recordable incident rate, preventable vehicle incident rate, business-unit performance, and an individual performance modifier.[333] According to TGS, these measures provide a direct benefit to customers, shareholders, and employees because they: encourage employees to be good stewards of expenses, practice safe driving and operating behaviors, provide safe and reliable service, and encourage decisions that help keep customer rates lower than they otherwise would have been.[334] TGS states that the provision of STI is common among utilities and that the Commission has allowed at least two other utilities in Texas—CenterPoint and Atmos—to recover for incentive compensation.[335]

TGS also cites a 2015 Southern Gas Association Compensation Survey, which showed that 100 percent of participating companies where TGS operates offer STI.[336] TGS provided

[329] TGS Ex. 5 (Lawhorn Test.) at 17.
[330] *Id*. at 18.
[331] TGS Ex. 11 (Kern Test.) at 7.
[332] *Id*. at 7.
[333] *Id*. at 5, 7-10.
[334] *Id*. at 8.
[335] *Id*. at 5, 7-10.
[336] TGS Ex. 22 (Kern Rebuttal Test.) at 11.

examples of how financial metrics benefit ratepayers because of the alignment of TGS and customer interests, including: developing and implementing cost saving ideas, such as paperless billing enrollment; restructuring the customer mailing process to optimize the mail customers receive; improving the self-service capability on the TGS website, which reduces labor expenses; and shifting calls during emergencies to an Oklahoma Natural Gas agent when TGS agents are unavailable. TGS says it observed a 30-percent improvement in the average speed of answered emergency calls—from 10 seconds to 7 seconds—thus resulting in better performance at no additional cost.[337]

Long-Term Incentive (LTI)

TGS requests a total LTI amount of $597,502. There are 116 employees eligible for the LTI plan, of which 84 percent are non-officer employees.[338] TGS grants two types of LTI—restricted units and performance units. Restricted unit LTI is not based on financial performance, but rather is designed to encourage an employee to remain with TGS to reduce turnover and retain experienced employees.[339] The test year restricted unit LTI amount is $221,440.[340] Awards for performance units are based on the total shareholder return of ONE Gas.[341] The test year performance unit LTI amount is $376,062.[342]

According to TGS, LTI is required to attract, motivate, and retain key employees—including executives and managers—and encourage them to make business decisions that create value for all stakeholders, including ratepayers.[343] Without it, TGS states that ONE Gas would see a departure of skilled employees, reduced levels of service and customer satisfaction, and increased difficulty recruiting new employees.[344] TGS provided evidence that each of the 12 companies in its peer group has an LTI program, including three surveys showing that at least 65 percent of surveyed companies—including CenterPoint and Atmos—provide some form of LTI.[345] TGS explained that the program is designed to ensure that executives and key employees are making good decisions on TGS's behalf over the long term that align with the interests of TGS's customers and other shareholders.[346] According to TGS, retaining key employees, who have valuable knowledge of the systems and operations, reduces the need and cost to recruit, hire and train new employees.[347]

Opposition by CEP and Coalition

In opposition, CEP and Coalition recommend that TGS recover only 10 percent STI, which is based on the test-year payout for non-financial goals, and recover no LTI. In support, CEP provided testimonial evidence from Mark Garrett (J.D.), an attorney, certified public

[337] TGS Ex. 9 (Edwards Test.) at 24.
[338] TGS Ex. 22 (Kern Rebuttal Test.) at 12.
[339] Tr. at 91 (July 21, 2016) (Kern testifying).
[340] TGS Ex. 21 (Edwards Rebuttal Test.) at 4, 17.
[341] TGS Ex. 22 (Kern Rebuttal Test.) at 12.
[342] TGS Ex. 21 (Edwards Rebuttal Test.) at 4, 17.
[343] TGS Ex. 11 (Kern Test.) at 10.
[344] *Id*. at 12-15.
[345] *Id*. at 12-13.
[346] *Id*. at 13
[347] *Id*.

accountant, and President of Garrett Group, LLC, a firm specializing in public utility regulation, litigation, and consulting services.[348]

Generally, CEP explains that the issue is not the overall compensation practices of ONE Gas, but rather whether TGS met its burden of proving that the inclusion of incentive compensation based on financial metrics is a reasonable and necessary operating expense to be charged to ratepayers.[349] CEP offers that a ONE Gas corporate proxy statement describes executive compensation as creating value for shareholders and that the total compensation of the executives, including incentive compensation, was several times the amount of base salary.[350] CEP notes that TGS is abandoning its 2014 agreement with the City of El Paso to not request 75 percent of incentive compensation.[351] CEP also notes that in GUD No. 9988—a litigated rate case—the Commission disallowed the portion of STI related to financial performance measures, allowed only the portion of STI that was based on safety metrics.[352]

Coalition acknowledges the importance of awarding bonuses to employees, but argues "the payouts must be proportionately shared by the company and the ratepayers and the payout amounts must be adequately supported and related to a goal which benefits both consumer ratepayers and shareholders."[353] According to Coalition, both STI and LTI "should not, fully and literally, be at the ratepayer's expense."[354]

In response, TGS maintains that recovery of incentive compensation is a reasonable and necessary expense, arguing that GUD 9988 reflects an outdated approach on incentive compensation.[355] According to TGS, the Commission's decisions have evolved regarding the recovery of incentive compensation linked to financial metrics, as shown in GUD Nos. 10000 and 10170.[356] TGS maintains that offering incentive compensation is consistent with industry practice, TGS's plans are designed consistent with the market, and the use of financial metrics benefits customers.[357] Finally, TGS argues that the evidence here establishes that all ONE Gas employees, including executive management, are solely focused on regulated natural gas distribution utility operations, and thus all employees—from executives to direct WTSA employees—are focused on providing safe and reliable service.[358]

<u>CEP's Recommendation for STI</u>

CEP recommends the Commission exclude the 90 percent of STI related to financial metrics and include only the 10 percent of STI that is related to safety metrics. CEP explains that while the STI plan is broken down into 75 percent financial performance and 25 percent safety-related, the payout levels for the test year were 90 percent financial and 10 percent

[348] CEP Ex. 2 (Garrett Test.) at 3.
[349] CEP Initial Br. at 19.
[350] CEP Ex. 6 (SEC Schedule 14A "ONE Gas, Inc."), p. 11.
[351] Tr. at 23-24 (July 19, 2016) (Lawhorn testifying).
[352] CEP Ex. 2 (Garrett Test.) at 14.
[353] Coalition Initial Br. at 5.
[354] *Id*.
[355] TGS Reply Br. at 15-17.
[356] TGS Ex. 9 (Edwards Test.) at 22; TGS Ex. 21 (Edwards Rebuttal Test.) at 3-6.
[357] TGS Ex. 9 (Edwards Test.) at 22-25; TGS Ex. 21 (Edwards Rebuttal Test.) at 8-11; TGS Ex. 22 (Kern Rebuttal Test.) at 5-12.
[358] TGS Reply Br. at 16; TGS Ex. 21 (Edwards Rebuttal Test.) at 4.

safety.[359] CEP states that TGS's plan remains "weighted heavily" toward financial rather than operational measures, and points out that incentive compensation levels have fluctuated in the past.[360]

CEP offers that, "in most jurisdictions," the cost of incentive plans that are tied to financial performance measures are excluded for ratemaking purposes, "generally" for the following reasons:

- payment is uncertain;
- many of the factors that significantly impact earnings are outside the control of most company employees and have limited value to customers;
- earnings-based incentive plans can discourage conservation;
- the utility and its stockholders assume none of the financial risks associated with incentive payments;
- incentive payments based on financial performance measures should be made out of increased earnings; and
- incentive payments embedded in rates shelter the utility against the risk of poor earnings performance.[361]

CEP notes decisions by Oklahoma's Corporation Commission, which allowed 50 percent STI in two settled cases, did not allow any financial performance-linked STI in two litigated cases.[362] CEP also provided a multi-state survey showing that a majority of states in the survey excluded incentive payments associated with financial performance from rates, and showing that none of the states in the survey allowed full recovery of incentive compensation in rates.[363]

As an alternative to allowing only 10 percent STI, CEP suggests splitting the incentive plan costs 50/50 between ratepayers and shareholders—the approach taken in several states that CEP acknowledges reflects a "belief" that incentive compensation plans benefit both ratepayers and shareholders alike.[364]

In response, TGS argues that CEP's position reflects a lack of understanding of the types of compensation utilities must offer to attract and retain employees to remain competitive and provide service.[365] TGS explains that all ONE Gas employees are required to operate in a cost-effective manner, including executive management, which provides necessary services such as operations, maintenance, construction, engineering and customer service.[366] According to TGS, Commission precedent requires that TGS recover incentive compensation—both STI and LTI—awarded to WTSA employees.[367] Alternatively, should the Commission consider reducing

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[359] CEP Ex. 2 (Garrett Test.) at 14-15.
[360] *Id*. at 14, 28.
[361] *Id*. at 17-19.
[362] *Id*. at 15.
[363] Id. at 20.
[364] *Id*. at 28-29.
[365] TGS Ex. 22 (Kern Rebuttal Test.) at 5-6.
[366] TGS Ex. 21 (Edwards Rebuttal Test.) at 4-5.
[367] *Id*.

TGS's requested recovery of 100 percent STI, TGS alternatively recommends removing only $595,665 to account for variance based on TGS's actual performance.[368]

CEP's Recommendation for LTI

CEP recommends the Commission exclude 100 percent of LTI. CEP argues that the interests of TGS and its customers are not always the same, and therefore not all of executive compensation is presumed to be a necessary cost of providing utility service.[369] CEP explained that there should be a financial benefit to TGS from the long-term incentive compensation and that benefit should be paid from the additional funds generated by the achievement of the goals of those executives.[370]

In response, TGS maintains that offering incentive compensation is consistent with industry practice, TGS's plans are designed consistent with the market, and the use of financial metrics benefits customers.[371] According to TGS, CEP's arguments regarding the recovery of executive compensation are misplaced because all ONE Gas employees, including management, are solely focused on regulated natural gas distribution utility operations.[372] TGS also states that CEP ignores that not all LTI is tied to financial goals—an employee will receive "restricted units" if he or she is still an employee three years after the grant date and thus is not based on financial performance.[373]

Examiner Findings and Recommendation

The Examiners find that the weight of the evidence supports partial—but not total—recovery for both STI and LTI. While both TGS and CEP provided evidence of previous Commission decisions and decisions from other states to support their respective arguments, those prior decisions do not bind the Commission here and the Examiners gave them very little weight. Instead, the Examiners based the findings herein on the evidence unique to this case. Here, the weight of the evidence establishes that portions of both STI and LTI are reasonable and necessary and supported by the evidence.

Short-Term Incentive (STI)

The weight of the evidence supports partial cost recovery of TGS's requested STI amount. The evidence supports that both shareholders and ratepayers benefit—to some degree—from STI, which includes both safety and financial metrics. The precise degree of benefit to each is not quantified—and may not be quantifiable—but the evidence supports that a benefit exists. The evidence shows that STI payout levels are variable, thus the amount paid out in the test year will not necessarily be the amount paid out in subsequent years. One of the components of the STI metric is a performance modifier, which varies from 0 percent to 125 percent based on TGS's actual performance. The evidence further establishes that the test year STI amount

[368] *Id*. at 16.
[369] CEP Ex. 2 (Garrett Test.) at 32.
[370] *Id*. at 34-35.
[371] TGS Ex. 9 (Edwards Test.) at 22-25; TGS Ex. 21 (Edwards Rebuttal Test.) at 8-11; TGS Ex. 22 (Kern Rebuttal Test.) at 5-12.
[372] TGS Ex. 21 (Edwards Rebuttal Test.) at 4.
[373] TGS Ex. 22 (Kern Rebuttal Test.) at 12-13.

greater than 100 percent is $595,665. The Examiners recommend excluding this amount from STI to eliminate the variability. Without a way to quantify benefit to ratepayers with precision, the Examiners recommend splitting the remainder of the STI—$1,634,189—evenly between ratepayers and shareholders, with recovery allowable for the half attributable to ratepayer benefit. The result is a total STI of $817,095, an expense the Examiners find to be reasonable and necessary, supported by the evidence, and consistent with GURA Section 104.051 (Establishing Overall Revenues) and Chapter 104 (Rates and Services).

Long-Term Incentive (LTI)

The weight of the evidence also supports partial cost recovery of TGS's requested LTI amount. The evidence supports that both shareholders and ratepayers benefit—to some degree—from LTI, which is based both on financial and non-financial performance. Like with STI, the precise degree of benefit to each is not quantified—and may not be quantifiable—but the evidence supports that a benefit exists. The evidence shows that the LTI metric is based on both encouraging employee retention and shareholder return. The evidence establishes the test-year LTI amount based on shareholder return was $376,062. The Examiners recommend excluding this amount from LTI for cost recovery because it is based solely on shareholder return and not a direct benefit to ratepayers. Without a way to quantify benefit to ratepayers with precision, the Examiners recommend splitting the remainder of the LTI—$221,440—evenly between ratepayers and shareholders, with recovery allowable for the half attributable to ratepayer benefit. The result is a total LTI of $110,720, an expense the Examiners find to be reasonable and necessary, supported by the evidence, and consistent with GURA Section 104.051 (Establishing Overall Revenues) and Chapter 104 (Rates and Services).

Conclusion

Considering the evidence, the Examiners recommend a combined STI and LTI recovery of $927,815—an expense the Examiners find to be a reasonable and necessary, supported by the evidence, and consistent with the requirements of GURA Section 104.051 (Establishing Overall Revenues) and Chapter 104 (Rates and Services).

3. Pipeline Integrity Expenses

TGS requests $531,670 for pipeline integrity expenses if its request to recover this expense through a rider is not approved.[374]

Staff recommends that TGS continue the use of a Pipeline Integrity Testing ("PIT") Rider to recover expenses related to integrity testing, as was decided in GUD Nos. 9988, 10069, and 10142.[375]

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that recovery of these pipeline integrity expenses through a PIT Rider, as Staff recommends, is just and reasonable. Accordingly, the

[374] TGS Ex. 8 (Buchanan Test.) at 5.
[375] Staff Ex. 2 (Cromleigh Test.) at 19.

Examiners recommend that TGS continue collecting these pipeline integrity expenses through the PIT Rider, and consequently adjusting TGS's total operating expenses downward by $531,670.

4. Base Payroll, Overtime Expenses, and Payroll Taxes

TGS requests $13,876,845 for base payroll expenses and $1,541,630 for overtime expenses. In support, TGS states that as a 100 percent regulated gas utility, all labor costs are necessary to provide gas utility service and those costs are within market norms.[376] TGS offers that its proposed payroll adjustment is consistent with prior Commission dockets and ensures that the expenses included in rates reflect TGS's actual, ongoing costs, which is just and reasonable.[377]

Staff does not oppose TGS's proposed adjustments.

Opposition by CEP

In opposition, CEP objects to TGS's proposed payroll adjustments, arguing that TGS's methodology used for payroll annualization is "not considered an acceptable method" and produced an unreasonable result.[378] According to CEP, TGS's methodology is unacceptable because it annualizes base payroll costs at December 2015—three months after the end of the test year.[379] Rather than TGS's requested 7.33 percent increase in payroll expenses, CEP recommends a 3-percent increase, which would reduce TGS's requested payroll expense increase for the WTSA by $592,565.[380] According to CEP, this recommended adjustment impacts overtime costs and payroll taxes, resulting in expense reductions of $54,246 and $208,214, respectively.[381]

In response, TGS argues that CEP's recommended adjustments should be rejected.[382] TGS states that its use of December 2015 data reflects TGS's actual, ongoing costs and is therefore appropriate and reasonable.[383] TGS states that its pay increases are awarded in December and there has been "no significant decline in headcount" since December 2015, and so using December 2015 data is "known and measurable" and consistent prior Commission cases.[384] TGS also provided evidence that its base salary is on average 11 percent below the market median.[385] TGS states that, because CEP's recommended adjustment to payroll should be rejected, so too should its proposed adjustments to payroll overtime and payroll tax expense.[386]

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[376] TGS Ex. 5 (Lawhorn Test.) at 13-14, 16-19.
[377] TGS Ex. 20 (Buchanan Rebuttal Test.) at 2-5.
[378] CEP Ex. 2 (Garrett Test.) at 41.
[379] *Id*. at 41-44.
[380] *Id*. at 41-43.
[381] *Id*. at 43-44 (for the WTSA).
[382] TGS Ex. 20 (Buchanan Rebuttal Test.) at 2-6.
[383] *Id*. at 2.
[384] *Id*. at 3.
[385] TGS Ex. 22 (Kern Rebuttal Test.) at 3-5.
[386] TGS Reply Br. at 15; TGS Ex. 20 (Buchanan Rebuttal Test.) at 5.

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that TGS's requested base payroll and overtime expenses are reasonable and necessary. The evidence shows: that the payroll adjustment is known and measurable and reflects ongoing expenses, that TGS's base salary is below the market median, and that the overtime adjustment is related to the payroll adjustment. The Examiners recommend approval of TGS's requested base payroll and overtime expenses, which are reasonable and necessary, supported by the evidence, and consistent with requirements of GURA Section 104.051(Establishing Overall Revenues) and Chapter 104 (Rates and Services). Regarding payroll taxes, the Examiners recommend an adjustment downward of $114,697 due to the above recommendations to reduce short-term incentive compensation.

5. Supplemental Employee Retirement Plan (SERP)

TGS requests recovery of Supplemental Employee Retirement Plan ("SERP") expenses totaling $73,831. SERP is a non-qualified pension plan.[387] The Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006 ("PPA") impose limitations on the amount of compensation that can be accumulated under TGS's basic retirement plan.[388] The retirement benefit for highly compensated employees, as a percentage of salary, is less than the maximum benefit available to other employees through the pension plan.[389] According to TGS, the primary benefit of SERP is to offer highly-compensated employees the same benefits that other employees receive from the basic retirement plan, on a percentage-of-salary basis.[390]

Staff does not oppose TGS's proposed cost recovery for SERP.

Opposition by CEP

In opposition, CEP objects to all SERP cost recovery. CEP acknowledges that SERP costs are presently low, but recommends they be disallowed "as a matter of principle" because, CEP argues, ratepayers should not bear the additional costs associated with supplemental benefits to highly-compensated executives since these costs "are not necessary for the provision of utility service, but are instead discretionary costs of the shareholders designed to attract, retain, and reward highly compensated employees."[391] CEP argues that SERP is aligned with the interests of shareholders and has been disallowed in many jurisdictions.[392]

In response, TGS maintains that SERP costs are reasonable and necessary and TGS cannot be competitive without a SERP plan.[393] According to TGS, retaining executives relates to providing safe and reliable gas service and therefore is not a "discretionary" cost as argued by CEP.[394] TGS notes that the Commission approved recovery of SERP for Atmos Mid-Tex

[387] TGS Ex. 22 (Kern Rebuttal Test.) at 15.
[388] *Id*.
[389] *Id*.
[390] *Id*.
[391] CEP Ex. 2 (Garrett Test.) at 37.
[392] *Id*. at 36-41.
[393] TGS Ex. 22 (Kern Rebuttal Test.) at 16.
[394] *Id*.

Division employees in GUD No. 10170.[395] Finally, TGS argues that TGS's SERP request is appropriate because it allows TGS to provide a comprehensive compensation package to retain qualified executives, who otherwise might leave TGS for additional retirement benefits at another company.[396]

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that a portion of TGS's requested SERP expenses are reasonable and necessary. The evidence shows that SERP is beneficial to recruit and retain executives, which benefits both shareholders and ratepayers. The evidence does not support recovery of all SERP expenses, however. Rather, the evidence supports recovery only of the portion of SERP expenses directly assigned to the WTSA direct payroll—$1,805. This amount is reasonable and necessary, supported by the evidence, and consistent with the requirements of GURA Section 104.051 (Establishing Overall Revenues) and Chapter 104 (Rates and Services). Accordingly, the Examiners recommend partial recovery of SERP expenses in the amount of $1,805.

6. Injuries and Damage Expenses

TGS requests $217,495 for injuries and damages expenses. In calculating these expenses, TGS states that it relied on a four-year average of workers' compensation, auto, and general liability claims paid by TGS.[397] According to TGS, a similar four-year average was used in several past Commission dockets.[398]

Staff does not oppose TGS's requested amount.

Opposition by CEP

In opposition, CEP recommends that the injuries and damages expense be based on test-year actual rather than TGS's proposed four-year average.[399] According to CEP, the four years included in TGS's review "show that claims have generally decreased over this period, and reached their lowest level in the test year."[400] CEP's recommendation would reduce TGS's requested injuries and damages expenses for the WTSA by $15,697.[401]

In response, TGS maintains that TGS's reliance on a four-year average of injuries and damages is appropriate and should be approved.[402] According to TGS, expense related to injuries and damages fluctuates from year to year, and using a four-year average mitigates the year-to-year volatility.[403]

[395] *Id*.
[396] *Id*. at 16-17.
[397] TGS Ex. 20 (Buchanan Rebuttal Test.) at 6-7.
[398] *Id*. at 6-7.
[399] CEP Ex. 2 (Garrett Test.) at 45-46.
[400] *Id*. at 45.
[401] *Id*. at 45-46.
[402] TGS Ex. 20 (Buchanan Rebuttal Test.) at 6-7.
[403] *Id*.

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that TGS's requested expenses for injuries and damages is reasonable and necessary and supported by the evidence. The evidence shows that injuries and damages expenses can vary from year to year, and using a four-year average is a reasonable approach to mitigate that variance. Accordingly, the Examiners recommend approval of TGS's requested injuries and damages expenses totaling $217,495. This amount is reasonable and necessary, supported by the evidence, and consistent with GURA Section 104.051 (Establishing Overall Revenues) and Chapter 104 (Rates and Services).

7. Journey Expenses

For the same reasons it recommends excluding Journey from rate base, as treated above, CEP recommends excluding Journey-related expenses during the test year.[404]

In response, TGS maintains that Journey-related expenses are reasonable and necessary and should be recovered in rates.[405] According to TGS, CEP offers no evidence to justify a disallowance of Journey-related expenses.[406]

Examiner Findings and Recommendations

As treated above in the rate base section, the Examiners found that Journey-related assets: are used and useful in providing service to customers; currently are in service; and increase the safety and reliability of the system, including assets in the WTSA. Furthermore, the Examiners found that Journey benefits customers, and that those benefits will increase over time. Accordingly, and considering the evidence, the Examiners find that Journey-related expenses are reasonable and necessary operating expenses consistent with GURA Section 104.051 (Establishing Overall Revenues) and Chapter 104 (Rates and Services).

8. Unchallenged Amounts

As found above, TGS established that it keeps its books and records in accordance with Commission rules. Accordingly, the unchallenged amounts shown on TGS's books and records, as well as summaries and excerpts therefrom, are presumed to have been reasonably and necessarily incurred.[407]

9. Operations and Maintenance Expenses Conclusion

The Examiners find that operations and maintenance expenses totaling $50,503,100 is reasonable and necessary, supported by the evidence, and consistent with GURA Section 104.051 (Establishing Overall Revenues) and Chapter 104 (Rates and Services). Accordingly, the Examiners recommend approval of this amount.

[404] CEP Trial Br. at 28.
[405] TGS Reply Br. at 22.
[406] *Id*.
[407] *See* 16 Tex. Admin. Code § 7.503(a) (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities).

D. Revenue Requirement Conclusion

The Examiners find that an overall revenue requirement of $78,171,546 for the WTSA is just and reasonable, supported by the evidence, and permits TGS a reasonable opportunity to earn a reasonable return on TGS's invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expense.

IX. CLASS COST OF SERVICE STUDY, REVENUE ALLOCATION, AND RATE DESIGN

How to properly recover TGS's revenue requirement from WTSA customers is a major point of disagreement among the parties. Current EPSA, PSA, and DCSA rates and rate structures differ among these service areas, and between the incorporated and environs areas within each area. TGS proposes identical rates for all customers in each customer class throughout the WTSA. [408]

TGS, CEP, and Staff each provided evidence in support of their respective positions. TGS provided testimonial evidence from F. Jay Cummings (Ph.D, Economics), an independent consulting economist.[409] CEP provided testimonial evidence from Clarence L. Johnson (M.A., Interdisciplinary/Urban Studies), a self-employed consultant on energy and utility regulatory issues,[410] and from Karl J. Nalepa (M.S., Petroleum Engineering), President of ReSolved Energy Consulting, LLC, an independent utility consulting company.[411] Staff provided testimonial evidence from Frank M. Tomicek, a Financial Analyst in the Commission's Market Oversight Section of the Gas Services Division.[412]

The major components of this process involve: TGS's class cost of service ("CCOS") study; class revenue allocation; and rate design. Each of these components is treated separately, below.

A. Class Cost of Service (CCOS) Study

TGS provided a CCOS study for the WTSA based on the revenue requirement requested in the SOI.[413] A CCOS study fully allocates a utility's cost of service, or revenue requirement, to each customer class.[414] The components of a utility's revenue requirement, i.e., operating expenses, depreciation, taxes, and required return, are distributed to each customer class based on cost causation principles.[415] This type of study is frequently termed a fully-allocated CCOS study.[416]

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[408] TGS Ex. 17 (Cummings Test.) at 3.
[409] TGS Ex. 17 (Cummings Test.); TGS Ex. 26, Rebuttal Testimony of F. Jay Cummings on Behalf of Texas Gas Service Company ("Cummings Rebuttal Test.).
[410] CEP Ex. 5, Direct Testimony of Clarence L. Johnson on Behalf of the City of El Paso ("Johnson Test.").
[411] CEP Ex. 4, Direct Testimony of Karl J. Nalepa on Behalf of the City of El Paso ("Nalepa Test.").
[412] Staff Ex. 1 (Tomicek Test.).
[413] TGS Ex. 17 (Cummings Test.) at 3, 16-30, and at Exhibit FJC-1 (Class Cost of Service Study).
[414] *Id*. at 16.
[415] *Id*.
[416] *Id*.

TGS Witness Cummings developed the CCOS study. Dr. Cummings explained that the CCOS study provides a useful guide in distributing the revenue requirement to the customer classes because interclass equity considerations require that each customer class pay the cost to serve that class.[417] TGS offers that the methods, classification and allocation factors in the CCOS study are the same as those used by TGS in its CCOS study in GUD No. 9988, with the exception that shared services expenses are no longer classified as customer-related costs in their entirety.[418] As in GUD No. 9988, TGS used a zero-intercept study to classify distribution mains and related expenses as both customer-related and demand-related.[419] TGS classifies distribution mains as 52 percent customer-related and 48 percent demand-related.[420] According to TGS, to meet its WTSA revenue requirement with rates that recover the actual cost to serve each customer class, the CCOS study supports revenue increases for the residential and Fort Bliss classes and revenue decreases for commercial, industrial, public authority, and municipal water pumping customers.[421]

Staff does not oppose TGS's CCOS study.

Opposition by CEP

In opposition, CEP states that TGS's CCOS study assigns an excessive portion of costs to the customer classification.[422] CEP disagrees with the use of a zero intercept method to classify a portion of the mains as customer-related, and instead recommends that all mains be allocated on a demand basis, or at minimum, only 36 percent of mains be classified as customer-related.[423] CEP applies the zero-inch quantification only to mains two inches or smaller because these are more likely to be closer to the end use customer.[424] CEP classifies the remainder of the mains as demand related because larger mains transport higher volumes of gas and are more closely related to demands.[425] CEP explains that the same logic for applying a zero intercept method to mains also applies to services, resulting in approximately 30 percent of service lines being classified as demand-related.[426] Ultimately, CEP offers that TGS's CCOS study is numerically precise but the classification and allocation choices involve subjective judgment.[427] CEP states that the Commission's use and acceptance of the CCOS study "should be tempered with the knowledge that components of the study may be reasonably disputed."[428]

In response, TGS characterizes CEP's changes as unreasonable and inconsistent with Commission orders pertaining to CCOS methods.[429] Regarding the classification of distribution mains, TGS explains that all installed footages are required to reach customer locations and are

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[417] *Id*.
[418] *Id*. at 22-23.
[419] *Id*. at 25.
[420] *Id*. at Exhibit FJC-1 (Class Cost of Service Study), pp. 3, 6, 8.
[421] *Id*. at 11.
[422] CEP Ex. 5 (Johnson Test.) at 5.
[423] *Id*. at 5-6.
[424] *Id*. at 17-23.
[425] *Id*. at 22.
[426] *Id*. at 23.
[427] *Id*. at 23-24.
[428] *Id*. at 24.
[429] TGS Ex. 26 (Cummings Rebuttal Test.) at 2.

sized to meet customer usage at the system peak.[430] TGS argues that the customer component measures the cost of providing customers with access to gas service, and the demand component measures the cost of sizing mains to meet peak loads.[431] TGS also notes previous Commission orders where the Commission approved the use of zero-intercept and minimum system studies to split the cost of mains between customer and demand components.[432] Regarding services, TGS explains that, while classified as 100 percent customer-related, services are not allocated based on customer count.[433] Rather services are allocated to customer classes based on weighted customer factors that take into account the typical size and resulting cost differences for typical services across the customer classes.[434] Finally, TGS notes that the same methods used in TGS's CCOS study were found reasonable in GUD No. 9988—the last EPSA rate case.[435]

Examiners Findings and Recommendations

Considering the evidence, the Examiners find that TGS's CCOS study is reasonable to use, and the Examiners recommend that it be used as a guide to design rates. The evidence shows that the CCOS study classifies and allocates costs in a fair, just, and reasonable manner, consistent with the CCOS study previously used for the EPSA.

B. Class Revenue Allocation

Class revenue allocation pertains to the assignment of revenue to each customer class so that the total revenue assigned equals the revenue requirement.[436] Upon assignment of revenues to each class, recurring monthly rates must be designed to collect the annual revenue assigned to the class.[437] TGS describes its proposed class revenue allocation as moving all classes toward their cost of service, while tempering the residential increases by limiting the size of the non-residential revenue reductions to only 25 percent.[438] According to TGS, its proposed rate design promotes interclass equity and more closely aligns rates with the principles of cost causation.[439] TGS states that WTSA non-residential classes are currently assigned revenues 133 percent to 446 percent above their cost of service, while residential classes are assigned only 75 percent of their cost of service.[440] According to TGS, not reducing revenues for any class perpetuates existing inequalities.[441]

TGS used its CCOS study to allocate TGS's cost of service to each customer class.[442] Based on the CCOS study, TGS offers three different methods to allocate revenue to customer classes: Revenue Allocation One ("Allocation 1"), which assigns revenue so each class pays its actual cost of service; Revenue Allocation Two ("Allocation 2"), which incorporates the principle of gradualism into the allocation process by limiting the cost-based revenue decrease to

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[430] *Id*. at 9.
[431] *Id*. at 9.
[432] *Id*. at 10.
[433] *Id*. at 16-17.
[434] *Id*. at 17.
[435] *Id*. at 22.
[436] TGS Ex. 17 (Cummings Test.) at 30.
[437] *Id*.
[438] *Id*. at 33-35.
[439] TGS Initial Br. at 37.
[440] TGS Ex. 17 (Cummings Test.) at Exhibit FJC-2 (Class Revenue Allocation).
[441] TGS Initial Br. at 37.
[442] TGS Ex. 17 (Cummings Test.) at 16.

25 percent for those class for which a cost-based revenue decrease is required; and a third allocation ("Allocation 3"), which minimizes the residential impacts while ensuring that no other class is assigned revenue that will move it further from a cost-based revenue assignment than it is presently.[443] TGS explains that Allocation 3 moves toward a cost-based revenue assignment for the residential class but results in no movement to cost-based revenue assignments for any of the other classes.[444]

TGS recommends Allocation 2, reasoning that this option "moves all classes toward cost-based revenue assignments but recognizes the need for gradualism by moderating the impact on the residential class in this case.[445]

Opposition by CEP and Staff

Neither CEP nor Staff recommends using TGS's preferred Allocation 2. CEP's recommendation is "conceptually consistent" with Allocation 3.[446] CEP recommends that the residential class bear the indicated increase in revenue requirement, but no other classes receive a base revenue reduction.[447] According to CEP, this approach recognizes that the current residential class base revenues are below cost, but avoids residential customers funding a revenue reduction for other classes.[448] Staff recommends using Allocation 3. According to Staff, this approach keeps the cost/revenue ratios constant for the other service classes and does not preclude movement to a gradualist rate design in future rate proceedings.[449]

In response, TGS maintains that its recommendation to use Allocation 2 is more consistent with the Commission's policy of moving customer classes toward cost-based revenue assignments than are the recommendations of Staff and CEP.[450]

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that using the Allocation 3 method to allocate the revenue requirement to WTSA customer classes is just and reasonable, supported by the evidence, and consistent with GURA Chapter 104 (Rates and Services). The evidence shows that WTSA non-residential classes are currently assigned revenues 133 percent to 446 percent above their cost of service, while residential classes are assigned only 75 percent of their cost of service. The evidence also shows that the revenue-to-cost ratio of the residential class moves closer to 1.0—from 0.7873 to 0.9191—under this allocation method, and that the revenue-to-cost ratios for the other classes stays constant. Accordingly, the Examiners recommend using the Allocation 3 method for class revenue allocation.

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[443] *Id*. at 32-34.
[444] *Id*. at 33.
[445] *Id*. at 34.
[446] CEP Ex. 5 (Johnson Test.) at 15-16.
[447] *Id*.
[448] *Id*.
[449] Staff Ex. 1 (Tomicek Test.) at 37.
[450] TGS Ex. 26 (Cummings Rebuttal Test.) at 4, 23-24.

C. Rate Design

TGS proposes collecting its revenue requirement through both a fixed monthly customer charge and a volumetric rate that varies with Ccf usage. TGS's current EPSA rate structure consists of a volumetric rate and a customer charge that includes the first 200 Ccf for residential customers and 100 Ccf for commercial, industrial, and public authority customers. TGS proposes eliminating this minimum amount, applying the volumetric charge to all volumes, and increasing the customer charge to $22.[451]

<u>Residential Minimum Bill</u>

According to TGS, the residential "minimum bill" practice should be eliminated for the following reasons: (1) it fails to recognize that all customers who use gas cause costs to be incurred; (2) it causes unreasonably high volumetric rates for usage over 200 Ccf; (3) it unduly impacts low-usage customers who may never use more than 40 Ccf per month; (4) it would require new implementation in the DCSA and PSA, neither of which currently use a minimum bill structure; and (5) EPSA customers are the only gas utility customers in Texas that use a minimum bill structure.[452]

Staff does not oppose TGS's proposal to eliminate the minimum bill.

In opposition, CEP explains that TGS's minimum bill has been effective since 2000 and TGS did not recommend changes in its previous litigated case, GUD No. 9988, or during the five-year period since.[453] CEP argues that TGS ignores its own principles used in GUD No. 9988, where TGS held the position that rate continuity and customer understandability were reasons to maintain the minimum bill.[454]

In response, TGS maintains that a residential minimum bill structure is outdated and no longer reasonable. According to TGS, eliminating the minimum bill is "responsible ratemaking based on sound Commission policy and long-standing Commission precedent recognizing that rates should be designed based on both fixed and variable costs."[455] TGS argues that the minimum bill structure puts an undue impact on higher-use residential customers and forces lower-use customers to pay for customers who use between 40 and 200 Ccf.[456]

<u>Residential Customer Charge</u>

TGS recommends increasing the customer charge to $22 for residential customers, which would collect 91 percent of residential fixed costs per bill, compared to the current customer charges collecting 57 percent of the fixed costs per bill.[457] TGS claims that this ensures, to the extent practicable, that disproportionately large winter bill impacts are avoided in various areas.[458] TGS also claims that if the customer charge is too low to fully recover fixed costs,

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[451] TGS Ex. 17 (Cummings Test.) at 46.
[452] TGS Ex. 26 (Cummings Rebuttal Test.) at 29-31.
[453] Tr. at 32-33, 35 (July 20, 2016) (Cummings testifying); CEP Initial Brief at 36.
[454] CEP Ex. 5 (Johnson Test.) at 12.
[455] TGS Reply Br. at 23-24; TGS Ex. 26 (Cummings Rebuttal Test.) at 27-28.
[456] TGS Ex. 26 (Cummings Rebuttal Test.) at 31-32.
[457] TGS Ex. 17 (Cummings Test.) at 47.
[458] *Id*.

moderate-and high-use customers will unfairly pay part of the cost to serve lower-use customers within their class.[459] TGS cites GUD Nos. 9869 and 9762, where the Commission allowed 87 percent and 80 percent, respectively, of the residential fixed costs per bill to be recovered through the customer charge.[460]

In opposition, Staff recommends a monthly WTSA customer charge within a range of \$12-\$14.[461] Staff states that a \$22 residential customer charge would be one of the highest in Texas and would affect low-income customers adversely.[462] Staff recommends a customer charge recovering at least 50 percent of class fixed costs, thus mitigating the impacts for customers accustomed to paying lower customer charges and recognizing the effects of annual customer charge increases resulting for future annual interim rate adjustment filings.[463]

Also in opposition, CEP describes TGS's proposed \$22 customer charge as defective because it includes both demand and customer costs.[464] CEP argues that the customer charge should include only the following customer costs: operations and maintenance expense for meters, services; meter reading and customer accounting; and depreciation on meter, regulator and service investment.[465] CEP estimates a proper charge of \$8.07.[466] CEP explains that given the nature of the EPSA with a high percentage of low-income customers, TGS's proposed \$22 customer charge would harm those residents.[467] CEP also offers statistics from the American Gas Association showing a \$11.25 national average customer charge and a \$13.24 charge for the West South Central region of the United States.[468]

In response, TGS maintains that a \$22 customer charge is reasonable and balances the average monthly bill impacts and winter bill impacts.[469] TGS explains that for every dollar the customer charge is reduced, there is only a \$0.02 to \$0.03 decrease to the average monthly bill, but a \$1.80 increase to the average winter bill.[470] According to TGS, Staff's recommended \$12-\$14 range inadequately collects fixed costs through the customer charge when compared to recent Commission orders that approve residential customer charge increases that collect a greater portion of fixed costs through the customer charge.[471] According to TGS, CEP provides no data or information to support its claim that low-income customers in the WTSA are low-use customers, nor does CEP account for the fact that many low-income customers may be relatively high-use customers because they reside in dwellings that are poorly insulated and are equipped with older, poorly maintained gas burning appliances.[472] TGS argues that CEP's proposed \$8.07 customer charge falls far short of the fixed costs per bill the Commission has approved in the past and excludes other directly customer-driven accounts.[473]

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[459] *Id*.
[460] *Id*.
[461] Staff Ex. 1 (Tomicek Test.) at 36.
[462] *Id*. at 35.
[463] *Id*. at 36.
[464] CEP Ex. 5 (Johnson Test.) at 10.
[465] *Id*. at 8-10.
[466] *Id*. at 9-10.
[467] *Id*. at 10-11.
[468] *Id*. at 11.
[469] TGS Ex. 26 (Cummings Rebuttal Test.) at 6, 14-18.
[470] TGS Initial Br. at 38; TGS Ex. 26 (Cummings Rebuttal Test.) at 7.
[471] TGS Ex. 26 (Cummings Rebuttal Test.) at 2-3.
[472] *Id*. at 29.
[473] *Id*. at 28.

Non-Residential Rates

TGS proposes simplifying its rate structure for its non-residential classes, which include the following: commercial, public authority, industrial and water pumping. According to TGS, most commercial, public authority, and industrial customers are served under four-block, declining rate designs in various areas.[474] For each of these classes, TGS proposes a rate design based on two blocks, one usage rate for the first 500 Ccf and a somewhat lower charge for usage over 500 Ccf.[475] TGS also proposes to change the customer charges by considering the fixed costs per bill determined in the CCOS study and the wide disparity among customer charged in the various areas.[476] TGS also proposes to set the cogeneration transportation customer charge equal to the other transportation classes and reduce the municipal water pumping customer charges to better align with the fixed costs.[477]

Staff does not oppose TGS's recommendations.

CEP recommends charges for non-residential classes that mostly reflect current amounts.[478]

Examiner Findings and Recommendation

Residential Minimum Bill

The Examiners find that eliminating the residential minimum bill structure in the WTSA is just and reasonable and supported by the evidence. The evidence shows that eliminating the residential minimum bill structure in the WTSA follows cost causation principles because it charges for all Ccf usage and is a conventional rate structure.

Residential Customer Charge

The Examiners find that a WTSA residential customer charge set at $15.70 is just and reasonable and supported by the evidence. The evidence supports that a $15.70 residential customer charge fairly and reasonably balances the interests of TGS and its WTSA customers, and would allow recovery for approximately 80 percent of the customer costs identified in TGS's CCOS study. The evidence shows that a higher customer charge benefits moderate and high users more than low users and likely will mitigate winter bill spikes. While Staff is concerned with the effects of annual customer charge increases resulting from future interim revenue adjustments, the evidence does not establish if or when TGS would make such filings.

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[474] TGS Ex. 17 (Cummings Direct Test.) at 50.
[475] *Id*.
[476] *Id*. at 50-51.
[477] *Id*. at 52.
[478] *See* CEP Ex. 4 (Nalepa Test.) at Attachment D (Summary Results of the West Texas Service Area Integrated Cost of Service Model).

Non-Residential Rates

The Examiners find that TGS's proposed formulas for calculating non-residential customer charges and the associated volumetric charges are just and reasonable and supported by the evidence. The evidence does not support CEP's recommendations.

Conclusion

Considering the evidence, the Examiners find that eliminating the residential minimum bill structure, setting a WTSA residential customer charge at $15.70, and using TGS's proposed formulas for calculating non-residential customer charges—and the associated volumetric charges—are just and reasonable, supported by the evidence, and consistent with the requirements of GURA Chapter 104 (Rates and Services). Accordingly, the Examiners recommend that the Commission adopt these recommendations.

X. RATE SCHEDULES AND TARIFFS

TGS proposed several rate schedules and tariffs reflecting TGS's requested rates. Consistent with its request to consolidate service areas, TGS proposes replacing all of the existing EPSA, PSA, and DCSA tariffs with a new set of WTSA tariffs.[479] The majority of TGS's proposed WTSA rate schedules and tariffs were not challenged. All the proposed tariffs for the WTSA are listed in Attachment C.

Staff recommended several revisions to the proposed WTSA tariffs to add clarity and avoid confusion for customers. TGS agreed to all of Staff's recommendations and since has updated the tariffs to reflect Staff's revisions.[480] A chart summarizing these tariff revisions is contained in Attachment C.

As TGS has agreed to all Staff's tariff revisions, there are no contested issues with respect to the contents of the rate schedules and tariffs now proposed by TGS.[481]

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that TGS's proposed rate schedules and tariffs, if revised to reflect Staff's recommendations, are just and reasonable, supported by the evidence, and consistent with applicable GURA and Commission requirements.

[479] TGS Ex. 7 (McTaggart Test.) at 15-32; *see also id*. at 15 n3 ("As indicated previously, the Company has not filed a SOI with the PSA Cities. Tariffs applicable to the PSA Cities would be withdrawn only upon approval and implementation of new rates and tariffs for the PSA Cities, which the Company intends to file once the results of this proceeding are known.").

[480] Texas Gas Service Company Trial Brief, filed July 18, 2016 ("TGS Trial Br."), at 28-30; Staff Initial Br. at 12-15.

[481] Staff continues to oppose the tapping fee provision, as a general policy issue, as described above.

XI. PRUDENCY REVIEW AND INTERIM RATE ADJUSTMENTS

A. Review for Reasonableness and Prudence

In the rate case a gas utility files or the Commission initiates after the implementation of an IRA under Commission Rule § 7.7101 (Interim Rate Adjustments), any change in investment and related expenses and revenues that have been included in any interim rate adjustment shall be fully subject to review for reasonableness and prudence.[482]

Here, TGS requests a finding of reasonableness and prudence for its capital investment in the WTSA made through December 31, 2015.[483] In support, TGS provided evidence that the capital investments included in its SOI filing are used and useful in providing utility service as of December 31, 2015, prudent, reasonable in amount, and necessary for TGS to maintain a safe and reliable system and to provide an appropriate level and quality of gas utility service to customers.[484] TGS states that capital investment in infrastructure and other assets is necessary to maintain and expand the natural gas system, with safety, reliability, and growth being the primary driving forces behind most capital investments made in the EPSA, PSA, and DCSA systems.[485] TGS provided evidence supporting that these capital investments are made in the system to: (1) add pipeline for serving new customers; (2) replace pipeline facilities that have reached the end of their useful service lives; (3) relocate pipeline facilities as required by city, county, and state roadway projects; and (4) comply with regulatory requirements established at the federal, state, and local levels.[486]

TGS also provided evidence that most of the major capital expenditures at the corporate level were associated with investment in computer software and hardware.[487] TGS offers that information technology provides critical services supporting all employees in their efforts to provide service safely and reliably to customers in the WTSA, and that these systems "provide the highest level of stability, reliability, and security."[488]

Duplicative Sales Tax

As part of Staff's review of the capital investment in this docket, Staff reviewed supporting documentation for a random sample of capital investment projects.[489] In response to discovery propounded by Staff, TGS identified $32,262 of duplicative sales tax that was included in TGS's capital investment.[490] The additional sales tax issue began in 2009 with TGS's implementation of Vortex software.[491]

All parties agree that this duplicative sales tax is not reasonable and should be removed from the cost of service in this docket. Staff and TGS agree that any money related to this

[482] 16 Tex. Admin. Code § 7.7101(j).
[483] TGS Ex. 1 (SOI) at 15.
[484] TGS Ex. 6 (Jarrett Test.) at 16-20; TGS Ex. 9 (Edwards Test.) at 15-20.
[485] TGS Ex. 6 (Jarrett Test.) at 17.
[486] *Id*.
[487] TGS Ex. 9 (Edwards Test.) at 15-16.
[488] *Id*. at 16.
[489] Staff Initial Br. at 19.
[490] *Id*.
[491] *Id*.

duplicative $32,262 recovered through IRA filings should be refunded to customers in the form of a bill credit.

With the exception of this $32,262 in duplicative sales tax, no other part of TGS's capital investment was challenged as being unreasonable or imprudent.

Examiner Findings and Recommendation

Considering the evidence, the Examiners find that capital investment in the WTSA made through December 31, 2015, was reasonable and prudent, with the exception of the $32,262 of duplicative sales tax discussed above. It is just and reasonable to refund this amount to affected customers in the form of a one-time bill credit, in the amounts listed below.

TABLE 13
IRA REFUND PER CUSTOMER

Customer Class	Average Bills at 12/31/10	Refund per Customer	Total
Residential	2,570,256	$0.12	$26,539
Commercial and A/c	148,524	$0.39	$4,847
Industrial & Stand By	533	$4.66	$207
Public Authority and A/C	11,021	$1.41	$1,291
Municipal Water Pumping	239	$6.19	$123
Transportation Standard – T-1	564	$23.33	$1,096
TOTAL REFUND			$34,104

The Examiners recommend approval of the reasonableness and prudence of the capital investment in the WTSA made through December 31, 2015, with the exception of $32,262 of duplicative sales tax. The Examiners further recommend refunding this amount to affected customers in the form of a one-time bill credit no later than 60 days following the final order in this docket. Confirmation of refund and a summary update of Vertex changes should be provided to the Commission's Market Oversight Division immediately upon completion.

B. Future Interim Rate Adjustment (IRA) Factors

After this rate case, TGS may file with the Commission a tariff or rate schedule that provides for an interim adjustment in TGS's monthly customer charge or initial block rate to recover the cost of changes in the investment in service for gas utility services.[492] Under Commission Rule § 7.7101 (Interim Rate Adjustments), the factors used to calculate the return on investment, depreciation expense, and incremental federal income tax used to compute the

[492] Tex. Util. Code § 104.301 (Interim Adjustment for Changes in Investment).

revenues to be collected through the IRA must be the same as those established by the Commission in this docket.[493]

Here, Staff recommends that GURA Section 104.301 (Interim Adjustment for Changes in Investment) and Commission Rule § 7.7101 (Interim Rate Adjustments) be strictly followed. Specifically, Staff recommends all depreciation rates, including the corporate rates, remain the same in future IRA filings.[494]

Examiner Findings and Recommendation

The Examiners find that the following IRA factors are just and reasonable, supported by the evidence, and consistent with GURA Section 104.301 (Interim Adjustment for Changes in Investment) and Commission Rule § 7.7101 (Interim Rate Adjustments). Consistent with Staff's recommendation, the Examiners recommend these factors be followed until changed by a subsequent general rate proceeding:

- The capital structure and related components reflected in this PFD;
- For the initial filing, the Net Investment, including the detail of Plant in Service amounts—along with the associated depreciation rate for each account—shall be as shown in WKP G-15.a.1 (direct), WKP G-15.b.1 (division), and WKP G-15.c.1 (corporate), attached;
- For the initial filing, the net plant in service shall be $303,583,671;
- For the initial filing, the customer charges or volumetric rates reflected in this PFD will be the starting rates to apply to any IRA adjustment; and
- The base rate revenue allocation factors to spread any change in IRA increase/decrease to the appropriate customer classes are as follows:

Customer Class	Examiners' Revenue	Percentage
Residential	$58,808,059	78%
Commercial	$10,331,980	14%
Industrial	$ 998,634	1.3%
Public Authority	$ 3,593,639	4.8%
Water Pumping	$ 199,817	0.26%
Fort Bliss	$ 1,644,545	2.2%
Total	$75,576,674	100%

[493] 16 Tex. Admin. Code § 7.7101(f)(5).
[494] Staff Ex. 2 (Cromleigh Test.) at 24-25.

XII. OTHER ISSUES

A. Public Interest Determination of ONE Gas Transaction

On May 3, 2016, the Commission determined in GUD No. 10488 that the transfer of TGS from ONEOK to ONE Gas was in the public interest, pursuant to GURA Section 102.051 (Report of Certain Transactions; Railroad Commission Consideration).[495] TGS filed its SOI before the Commission made this determination in GUD No. 10488. Because, at the time the SOI was filed, the GUD No. 10488 Final Order had not yet been rendered, TGS again requested this same public interest determination in this docket. Following the conclusion of GUD No. 10488, and this public interest determination by the Commission, the ALJ precluded litigation of the issue in this case.[496]

The Examiners find that the Commission's determination in GUD No. 10488—that the transfer of TGS from ONEOK to ONE Gas was in the public interest—resolved the issue and is binding in this docket. Therefore, the Commission need not treat the issue again.

B. Affiliate Expenses

TGS is a division, not an affiliate, of ONE Gas and did not incur any affiliate expenses during the test year.[497] Therefore, the Commission does not need to address affiliate costs under GURA Section 104.055(b) (Net Income; Allowable Expenses).

C. Rate Case Expenses

The rate case expenses associated with GUD Nos. 10506, 10536, and 10539 were consolidated into GUD No. 10521 and will be considered in that docket.[498]

XIII. CHANGES TO ORIGINAL PFD

On September 9, 2016, TGS, CEP, and Coalition each timely filed exceptions to the PFD. Having reviewed these filings, the Examiners determined it appropriate to issue this Amended PFD and Amended Proposed Final Order pursuant to Section 2001.062 (Examination of Record

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[495] *See* GUD No. 10488, *Statement of Intent of Texas Gas Service Company, A Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, Final Order, signed May 3, 2016, at Finding of Fact 47 ("TGS complied with the reporting requirements contained in Section 102.051 (Report of Certain Transactions; Railroad Commission Consideration) of the Texas Utilities Code when TGS separated from ONEOK to ONE Gas."), Finding of Fact 48 ("The separation of TGS from ONEOK to ONE Gas is in the public interest."), Conclusion of Law 29 ("TGS complied with the reporting requirements contained in Section 102.051 (Report of Certain Transactions; Railroad Commission Consideration) of the Texas Utilities Code when TGS separated from ONEOK to ONE Gas."), and Conclusion of Law 30 ("The separation of TGS from ONEOK to ONE Gas is in the public interest.").

[496] *See* Examiners' Letter No. 18 (Ruling on TGS's Motion to Preclude), issued July 8, 2016.

[497] TGS Ex. 7 (McTaggart Test.) at 8-9.

[498] *See* Examiners' Letter No. 12 (Rate Case Expense Docket), issued May 27, 2016; Examiners' Letter No. 21 (Consolidation of GUD No. 10536), issued July 22, 2016; and Examiners' Letter No. 25 (Consolidation of GUD No. 10539), issued Aug. 16, 2016.

by State Agency; Proposal for Decision) of the Texas Government Code[499] and Commission Rule § 1.141 (Proposals for Decision).[500] For purposes of Commission Rule § 1.141(d), this Amended PFD and Amended Proposed Final Order are being served on all parties, and so any amendments adopted by the Commission do not need to be "noted and embodied with specificity" in the Commission's Final Order.[501]

The Examiners' ultimate recommendations and underlying analyses in the original PFD have not changed. This Amended PFD corrects typographical and calculation errors, and adds clarifying language in certain sections, where appropriate. Changes include:

- Typographical corrections;
- Changes to the summary of recommendations (p. iii);
- Additional language in section "III. PROCEDURAL BACKGROUND" (p. 4) that discusses the timely filing of certain exceptions to the PFD, and replies to the exceptions, as well as the re-opening of the evidentiary record for the limited purpose of admitting TGS Exhibit 30b;
- The addition of TGS Exhibit 30b to the list of TGS's exhibits in Attachment A;
- Clarification in Attachment A that there is no TGS Exhibit 31;
- Added language and a chart in section "VII. CONSOLIDATION OF SERVICE AREAS" (p. 10) to better convey CEP's argument regarding rate impact of service area consolidation on EPSA customers;
- Added language in section "VII. CONSOLIDATION OF SERVICE AREAS" (p. 10) to better convey Coalition's opposition to service area consolidation;
- Added language in section "VII. CONSOLIDATION OF SERVICE AREAS" (p. 13) to clarify that the *City of Dallas* case involved different factual circumstances;
- Added language and analysis in section "VIII. REVENUE REQUIREMENT" (pp. 20-21) relating to tapping fees—specifically, that modified tapping fee language proposed by TGS in its exceptions to the PFD would not be discriminatory to WTSA customers, and that the Examiners recommend approval of this language;
- Added language in section "VIII. REVENUE REQUIREMENT" (p. 29) further clarifying the Examiners' findings and recommendation with respect to return on equity;
- Correction in section "VIII. REVENUE REQUIREMENT" (pp. 50-51) to fix an arithmetical error relating to short-term incentive compensation. The correct recommended recovery amount is $817,095. This change affects other components of the revenue requirement and reduces the recommended revenue requirement by

[499] Tex. Gov't Code § 2001.062(d) ("A proposal for decision may be amended in response to exceptions, replies, or briefs submitted by the parties without again being served on the parties.").

[500] 16 Tex. Admin. Code § 1.141(d) ("A proposal for decision or proposed order may be amended pursuant to exceptions, replies, or briefs submitted by the parties without again being served on the parties. Unless the amended proposal for decision is served on all parties, amendments adopted by the commission shall be noted and embodied with specificity in the commission's final order.").

[501] *See id*.

$79,133—from $78,250,679 to $78,171,546. This change also affects the volumetric rate for the residential class, decreasing this rate from $0.12307 to $0.12237. All major components that are changed are highlighted green on the attached schedules in Attachment D;

- Correction to the incentive compensation table in section "VIII. REVENUE REQUIREMENT" (p. 46) to show that the Commission allowed partial recovery of incentive compensation in GUD Nos. 9869 and 9762;
- Correction related to rate design in section "VIII. REVENUE REQUIREMENT" (p. 59) to correct the residential revenue-to-cost ratio to reflect the Examiners' revenue requirement recommendation as follows: 0.7873 to 0.9191;
- Correction related to rate design in section "VIII. REVENUE REQUIREMENT" (p. 61) to properly attribute the American Gas Association statistical reference to CEP and not TGS;
- Revision to the IRA base rate revenue allocation table in section "XI. PRUDENCY REVIEW AND INTERIM RATE ADJUSTMENTS" (p. 65) to reflect the base rate revenue allocation amounts to each customer class. This replaces the table in the original PFD that reflects the cost of service allocation amounts to each customer class; and
- The addition of section "XIII. CHANGES TO ORIGINAL PFD" (pp. 67-69) that discusses why the Examiners issued an Amended PFD and itemizes the notable amendments.

Notable changes to the schedules and relevant cells are highlighted in green in Attachment D. Schedule changes include:

- Correction to the customer bill impacts tab, per CEP's request. To do so, the Examiners had to correct the current and recommended rates tab;
- Correction to the short-term incentive compensation matrix to reflect the proper reduction amounts noted above, and a corresponding reduction of the volumetric rate from $0.12307 to $0.12237;
- Revision to the values on Excel line 43 of the "Class Revenue Allocation" tab to reflect the Examiners' recommended COS Revenue Increase to each customer class; and
- Other formulaic, flow-through changes resulting from the short-term incentive compensation reduction.

The Amended Proposed Final Order reflects these changes, where appropriate. As explained above, the Commission does not need to separately note and specify in its Final Order any adopted amendments contained herein.[502]

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[502] Separately noting adopted amendments, if any, is only required if an amended PFD is not served on all parties. *See* 16 Tex. Admin. Code § 1.141(d). Here, this Amended PFD and Amended Proposed Final Order are being formally served on all parties on the date of issuance—September 16, 2016.

XIV. CONCLUSION

The Examiners find that TGS's requested rate change is warranted. The recommendations contained herein are just and reasonable, supported by the evidence, consistent with the public interest, and proper under applicable Texas law. Accordingly, the Examiners respectfully recommend that the Commission approve these recommendations.

XV. FINDINGS OF FACT AND CONCLUSIONS OF LAW

The Findings of Fact and Conclusions of Law contained in the Amended Proposed Final Order, issued contemporaneously with this Amended PFD, are incorporated herein by reference.

SIGNED September 16, 2016.

John Dodson
Administrative Law Judge

Rose A. Ruiz

Rose Ruiz
Technical Examiner

James R. Currier III

James R. Currier III
Technical Examiner