



City of La Vernia
CITY COUNCIL MEETING
102 E. Chihuahua St., La Vernia, Texas 78121
September 05, 2024
5:30 PM

AGENDA

- 1. Call to Order**
- 2. Invocation & Pledge of Allegiance**
- 3. Citizens to Be Heard**
(At this time, citizens who have filled out a registration form prior to the start of the meeting may speak on any topic they wish to bring to the attention of the governing body so long as that topic is not on the agenda for this meeting. Citizens may speak on specific agenda items when that item is called for discussion. During the Citizens to Be Heard section no council action may take place and no council discussion or response is required to the speaker. A time limit of three minutes per speaker is permitted; the council may extend this time at their discretion.)
- 4. Consent Agenda**
(All consent agenda items are considered routine by the City Council and will be enacted by one motion. There will be no separate discussion of these items unless a Councilmember requests an item be removed and considered separately.)
 - A.** Minutes from the 08-22-24 regular City Council Meeting
 - B.** Financials from the month of August 2024
- 5. Proclamations**
 - A.** National Night Out Proclamation
- 6. Resolutions**
 - A.** Discuss and consider action on Resolution No.090524-01 - a budget policy
 - B.** Discuss and consider action on Resolution No. 090524-02 - A fund policy
- 7. Discussion/Action**
 - A.** Discuss and consider action on the proposed West Texas gas rate change
 - B.** Discuss and consider action on accepting the resignation of Councilmember Eric Rauschuber
 - C.** Discussion and possible action on appointing a new councilmember to fill a vacancy
- 8. Discussion Only**
 - A.** Discussion surrounding any final revisions to the draft permitted use chart before we enter into formal revision procedures
- 9. Items Specific to Future Line Items on the Agenda**
 - A.** Code Change Proposals - Garden Homes
 - B.** Final Budget and Tax Rate Adoption

C. Performance Reviews- City Administrator and Chief of Police

10. Adjourn

DECORUM REQUIRED

The presiding officer may rule out any disruptive behavior, including shouting or derogatory statements or comments. If this behavior continues, the Officer may request that the individual leave the meeting and, if refused, issue an order of removal.

The City Council for the City of La Vernia reserves the right to adjourn into executive session at any time during the course of this meeting to discuss any of the matters listed above, as authorized by the Texas Open Meetings Act, Texas Governmental Code §551.071 (Consultation with Attorney), §551.072 (Deliberations about Real Property), §551.073 (Deliberations about Gifts and Donations), §551.074 (Personnel Matters), §551.076 (Deliberations about Security Devices), and §551.087 (Economic Development), and any other provisions under Texas law that permit a governmental body to discuss a matter in closed executive session.

The City of La Vernia Council meetings are open to all persons, regardless of disability. The facility is wheelchair-accessible, and parking spaces are available. If you require special assistance, you must request accommodations 48 hours before this meeting. Braille is not available. Please contact the City Secretary at (830) 779-4541 or email Mfarrow@lavernia-tx.gov.

I, the undersigned authority, do hereby certify that the above Notice of Meeting of the governing body of the above-named La Vernia City Council is a true and correct copy of said Notice and that I posted a true and correct copy of said Notice on the bulletin boards of the City Hall of said La Vernia, Texas, a place convenient and readily accessible to the general public at all times, and said Notice was posted on **AUG 30, 2024 at 5:00 PM** and remained so posted continuously for at least 72 Hours preceding the scheduled time of said meeting.

Lindsey Wheeler, City Secretary



CITY COUNCIL MEETING

102 E. Chihuahua St., La Vernia, Texas 78121

August 22, 2024

7:00 PM

MINUTES

1. Call to Order

The meeting was called to order @ 7:00pm

PRESENT

Martin Poore
Dianell Recker
Gary Gilbert
Justin Oates
Garrett Rabel

ABSENT

Eric Rauschuber

2. Invocation & Pledge of Allegiance

Mayor Poore requested to forego the invocation and Pledge.

3. Citizens to Be Heard

(At this time, citizens who have filled out a registration form prior to the start of the meeting may speak on any topic they wish to bring to the attention of the governing body so long as that topic is not on the agenda for this meeting. Citizens may speak on specific agenda items when that item is called for discussion. During the Citizens to Be Heard section no council action may take place and no council discussion or response is required to the speaker. A time limit of three minutes per speaker is permitted; the council may extend this time at their discretion.)

None

4. Consent Agenda

(All consent agenda items are considered routine by the City Council and will be enacted by one motion. There will be no separate discussion of these items unless a Councilmember requests an item be removed and considered separately.)

A. Meeting minutes from the regular City Council Meeting on 07-11-2024

B. Financials and check register- month of July

Motion made by Recker, Seconded by Gilbert.
Voting Yea: Oates, Rabel

5. Ordinances

- A. Discuss and consider action on Ordinance No. 082224-01 a budget amendment for garbage rates

Motion made by Recker, Seconded by Oates.
Voting Yea: Gilbert, Rabel

6. Resolutions

- A. Discuss and consider action on Resolution No. 2024-082224-01 an interlocal agreement for Operation Lone Star

Chief Keil presented

Motion made by Recker, Seconded by Rabel.

Voting Yea: Gilbert, Oates

- B. Discuss and consider action on Resolution No. 082224-02 an Interlocal agreement for Healthcare Provisions

Motion made by Gilbert, Seconded by Recker.

Voting Yea: Oates, Rabel

- C. Discuss and consider action on Resolution No. 082224-03 an Interlocal agreement with San Antonio River Authority for Wastewater Treatment Services

Motion made by Oates, Seconded by Recker.

Voting Yea: Gilbert, Oates, Rabel

- D. Discuss and consider action on Resolution No. 082224-04 an Interlocal agreement with the Wilson County Tax Office

Motion made by Recker, Seconded by Gilbert.

Voting Yea: Oates, Rabel

- E. Discuss and consider action on Resolution No. 082224-05 appointing a City Secretary

Motion made by Oates, Seconded by Recker.

Voting Yea: Gilbert, Rabel

- F. Discuss and consider action on Resolution No. 082224-06 an update to the Personnel Policy

The council approved the personnel policy as listed with the addition of 6 weeks paid leave for paternity and adoption/foster.

Motion made by Recker, Seconded by Gilbert.
Voting Yea: Oates, Rabel

7. Discussion Action

- A. Discuss and consider action on the FY 2025 Holiday schedule
The council approved the holiday schedule as listed but will allow the City Administrator to make a revision pending a staff survey for the Christmas holiday week.
Motion made by Oates, Seconded by Recker.
Voting Yea: Gilbert, Rabel

8. Discussion Only

- A. Discuss the FY 24-25 City of La Vernia and La Vernia Municipal Development District proposed budget
Victor the City's financial advisor, gave a presentation regarding the proposed Tax rate.
The Council has requested to discuss further at a upcoming meeting. The Council requested that the meeting scheduled for September 12th be moved to September 5th and be scheduled as a joint budget workshop.

9. Items Specific to Future Line Items on the Agenda

- A. Joint budget hearing MDD and CC
September 5th
- B. West Texas gas rate change
September 5th
- C. Discussion surrounding upcoming fee schedule amendment
- D. Fund Policy
- E. Budget Policy
Permeated use chart on September 5th

10. Adjourn

@ 8:15pm

Motion made by Oates, Seconded by Rabel.
Voting Yea: Recker, Gilbert

DECORUM REQUIRED

Any disruptive behavior, including shouting or derogatory statements or comments may be ruled out of order by the Presiding Officer. Continuation of this type of behavior could result in a request by the Presiding Officer that the individual leave the meeting, and if refused, an order of removal.

The City Council for the City of La Vernia reserves the right to adjourn into executive session at any time during the course of this meeting to discuss any of the matters listed above, as authorized by the Texas Open Meetings Act, Texas Governmental Code §551.071 (Consultation with Attorney), §551.072 (Deliberations about Real Property), §551.073 (Deliberations about Gifts and Donations), §551.074 (Personnel Matters), §551.076 (Deliberations about Security Devices), and §551.087 (Economic Development), and any other provisions under Texas law that permit a governmental body to discuss a matter in closed executive session.

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I, the undersigned authority, do hereby certify that the above Notice of Meeting of the governing body of the above named La Vernia City Council is a true and correct copy of said Notice and that I posted true and correct copy of said Notice on the bulletin boards of the City Hall of said La Vernia, Texas, a place convenient and readily accessible to the general public at all times, and said Notice was posted on **Aug 19, 2024 at 5:00 PM** and remained so posted continuously for at least 72 Hours preceding the scheduled time of said meeting.

Lindsey Wheeler, City Secretary

Check Register History

A2
08 Section 4, Item B.

Vendor # Invoice #	Description	Date Due	Total Amount	Check-Acct	Inv Date
Vendor Name	PO Number	1099 Liq	Transaction #	Trans-MMY	Claim-Number
CC-Transaction CC-Vendor	CC-Name	CC-Card Number	CC-Invoice		Project-Number
Account Number	Account Description	Date Paid	Amount	Action	

*** Bank Account Activity By Fund ***

Fund Description	Cash-Account-Number	Total
Utilities Fund	40-100-150	158,880.41

*** Bank Account Activity By Fund ***

Fund Description	Cash-Account-Number	Total
MDD Account Fund	12-100-100	5,695.39

*** Bank Account Activity By Fund ***

Fund Description	Cash-Account-Number	Total
General Fund	10-100-100	106,314.58

*** Bank Account Activity By Fund ***

Fund Description	Cash-Account-Number	Total
PD FORFEITURE ACCOUNT	16-100-100	131.86

*** Grand Totals *** 271,022.24

TRIAL BALANCE - ALL FUNDS
August 2024

Section 4, Item B.

B Future period 06/2024

Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
A S S E T S							
COMBINED GENERAL FUND CHECKING 10-100-100	620,923.68 37,442.66	145,360.44 2,928,905.27	217,074.90 2,417,138.71	549,209.22			
TEXPOOL 10-100-175	885,784.79 859,714.90	.00 26,069.89	.00 .00	885,784.79			
CD- GENERAL FUND 10-100-200	700.00 .00	.00 700.00	.00 .00	700.00			
CREDIT CARD RECEIVABLE 10-110-200	4,984.15 .00	5,845.77 134,055.25	.00 123,225.33	10,829.92			
PREPAID EXPENSES (EOY) 10-110-400	.00 23,455.73	.00 1,920.10	.00 25,375.83	.00			
TAXES RECEIVABLES 10-110-415	10,292.54 10,292.54	.00 141,150.83	.00 141,150.83	10,292.54			
ALLOWANCE FOR UNCOLLECTABLE 10-110-416	-1,890.95 -1,890.95	.00 .00	.00 .00	-1,890.95			
ACCOUNTS RECEIVABLES 10-110-425	3,206.56 3,206.56	.00 409.05	.00 409.05	3,206.56			
SALES TAX RECEIVABLES 10-110-430	290,520.92 290,520.92	.00 .00	.00 .00	290,520.92			
FRANCHISE TAX RECEIVABLES 10-110-435	26,285.78 26,285.78	.00 .00	.00 .00	26,285.78			
DUE FROM CAYETANO 10-110-502	5,144.28 5,480.08	.00 .00	33.58 369.38	5,110.70			
DUE FROM MDD 10-110-503	550.00 .00	.00 550.00	.00 .00	550.00			
DUE FROM WS FUND 10-110-504	113,423.40 48,549.78	9,221.30 74,094.92	.00 .00	122,644.70			
Book Balancing Adjustment 10-110-999	176,208.20 .00	.00 176,208.20	.00 .00	176,208.20			
CAPITAL PROJECT - GENERAL FUND 11-100-100	307,864.15 .00	.00 1,357,252.90	.00 1,049,388.75	307,864.15			
TEXPOOL 11-100-175	910,724.93 .00	.00 1,010,724.93	.00 100,000.00	910,724.93			
ACCOUNTS PAYABLE 11-200-010	.00 .00	.00 48,400.00	.00 48,400.00	.00			
CASH ACCOUNT - MDD 12-100-100	-9,917.67 170,336.33	.00 385,451.00	7,680.91 573,385.91	-17,598.58			

TRIAL BALANCE - ALL FUNDS
August 2024

Section 4, Item B.

B Future period 08/2024

Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments			
					Debit	Dr-Rev	Credit	Cr-Rev
MDD CHECKING ACCOUNT 12-100-110	2,087,695.34 1,894,799.13	53,257.61 565,918.58	.00 319,764.76	2,140,952.95				
TEXPOOL 12-100-175	59,801.86 58,041.88	.00 1,759.98	.00 .00	59,801.86				
DUE FROM GENERAL FUND 12-110-100	16,597.42 .00	.00 24,127.42	.00 7,530.00	16,597.42				
SALES TAX RECEIVABLE 12-110-415	116,199.69 116,199.69	.00 55,169.83	.00 55,169.83	116,199.69				
CASH - STREET MAINTENANCE 14-100-100	163,552.52 478,182.43	27,077.74 266,591.30	.00 554,143.47	190,630.26				
TEXPOOL 14-100-175	270,053.09 262,105.08	.00 7,948.01	.00 .00	270,053.09				
HOTEL CASH 15-100-100	190,342.96 136,785.68	5,333.61 65,178.07	.00 6,287.18	195,676.57				
ACCOUNTS RECEIVABLE - HOTEL 15-110-425	6,287.18 6,287.18	.00 6,287.18	.00 6,287.18	6,287.18				
CASH - FORFEITURE 16-100-100	1,909.98 414.71	.00 7,182.73	.00 5,687.46	1,909.98				
GRANT FUND 18-100-100	-10,515.12 .00	.00 30,219.98	.00 40,735.10	-10,515.12				
COURTHOUSE SECURITY - CASH 25-100-100	249.86 4,332.47	43.38 29,327.46	.00 33,366.69	293.24				
DUE FROM GENERAL FUND 25-110-210	86.23 .00	12.85 314.45	.00 215.37	99.08				
COURT TECHNOLOGY - CASH ACCT 35-100-100	15,795.87 14,553.36	42.63 1,285.14	.00 .00	15,838.50				
DUE FROM GENERAL FUND 35-110-270	79.70 .00	16.05 287.87	.00 192.12	95.75				
COMBINED FUNDS CHECKING 40-100-100	206,659.53 235,105.32	11,238.95 71,833.52	11,058.95 100,099.31	206,839.53				
WATER/SEWER CHECKING ACCT 40-100-150	-417,977.39 -235,190.69	55,506.80 1,232,194.70	129,888.82 1,489,363.42	-492,359.41				
WATER/SEWER SAVINGS 40-100-155	.26 .26	.00 .00	.00 .00	.26				
DUE FROM GENERAL FUND 40-110-010	125.00 .00	.00 125.00	.00 .00	125.00				
ACCOUNTS RECEIVABLE - WATER 40-110-100	153,942.41 153,942.41	.00 .00	.00 .00	153,942.41				
ALLOWANCE FOR UNCOLLECTABLE 40-110-120	-7,651.52 -7,651.52	.00 .00	.00 .00	-7,651.52				

TRIAL BALANCE - ALL FUNDS
August 2024

Section 4, Item B.

B Future period 08/2024

Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
NSF CHECK CLEARING ACCOUNT 40-110-300	.00 .00	796.25 2,984.97	796.25 2,984.97	.00			
PREPAID EXPENSES (EOY) 40-110-615	.00 .00	.00 69,382.78	.00 69,382.78	.00			
LAND 40-180-100	31,158.15 31,158.15	.00 .00	.00 .00	31,158.15			
BUILDINGS AND IMPROVEMENTS 40-180-110	15,166.06 14,000.00	.00 1,166.06	.00 .00	15,166.06			
VEHICLES AND EQUIPMENT 40-180-120	589,279.55 594,079.55	.00 .00	.00 4,800.00	589,279.55			
INFRASTRUCTURE 40-180-130	9,471,571.78 9,471,571.78	.00 .00	.00 .00	9,471,571.78			
ACCUM DEPRECIATION - BUILDINGS 40-180-180	-13,929.00 -13,929.00	.00 .00	.00 .00	-13,929.00			
ACCUM DEPRECIATION - EQUIPMENT 40-180-185	-281,883.36 -281,883.36	.00 .00	.00 .00	-281,883.36			
ACCUM DEPR - INFRASTRUCTURE 40-180-190	-5,169,871.86 -5,169,871.86	.00 .00	.00 .00	-5,169,871.86			
REFUNDING 40-250-125	-361,000.00 -361,000.00	.00 .00	.00 .00	-361,000.00			
TRANSFER IN 40-900-100	.02 .02	.00 .00	.00 .00	.02			
UTILITIES CAPITAL PROJECT 41-100-100	61.26 60.74	.00 .52	.00 .00	61.26			
TEXPOOL 41-100-175	24.37 24.37	.00 .00	.00 .00	24.37			
WATER IMPACT FEES - CASH 50-100-100	75,309.27 73,178.68	.00 2,130.59	.00 .00	75,309.27			
SEWER IMPACT FEES - CASH 51-100-100	13,566.30 13,147.38	.00 418.92	.00 .00	13,566.30			
* TOTAL ASSETS	10,567,492.17 8,961,838.17	313,753.38 8,727,727.40	366,533.41 7,174,853.43	10,514,712.14			

LIABILITIES

ACCOUNTS PAYABLE 10-200-010	.00 12,957.62	59,168.27 1,049,526.62	59,168.27 1,036,569.00	.00			
DUE TO MDD FUND 10-200-012	16,597.42 .00	.00 2,530.00	.00 19,127.42	16,597.42			

TRIAL BALANCE - ALL FUNDS
August 2024

Section 4, Item B.

B Future period 08/2024

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AM

Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
CASH DRAWER OVER/UNDER 10-200-015	9.00 .00	.00 513.40	.00 522.40	9.00			
CHRISTMAS SAVINGS ROGER HORNER 10-200-098	425.00 .00	.00 .00	50.00 475.00	475.00			
ED- XMAS SAVE 10-200-099	50.00 50.00	.00 .00	.00 .00	50.00			
HF - XMAS SAVE 10-200-103	-100.00 -100.00	.00 .00	.00 .00	-100.00			
YG - XMAS SAVE 10-200-107	.00 3,450.00	.00 6,150.00	.00 2,700.00	.00			
TM- XMAS SAVE 10-200-112	900.00 1,150.00	.00 1,300.00	150.00 1,200.00	1,050.00			
DKEIL- XMAS SAVE 10-200-117	1,080.00 1,380.00	.00 1,560.00	180.00 1,440.00	1,260.00			
LFLORES X-MAS SAVINGS ACCOUNT 10-200-121	.00 300.00	.00 2,100.00	.00 1,800.00	.00			
DBUNTE X-MAS SAVINGS ACCOUNT 10-200-122	720.00 805.00	.00 910.00	120.00 945.00	840.00			
TBECK- XMAS SAVINGS 10-200-123	.00 1,150.00	.00 1,600.00	.00 450.00	.00			
JVALDEZ - XMAS SAVINGS 10-200-124	2,100.00 1,800.00	.00 2,700.00	450.00 3,450.00	2,550.00			
SGOOLSBY- XMAS SAVINGS 10-200-125	450.00 460.00	.00 520.00	75.00 585.00	525.00			
HRIOS- X-MAS SAVINGS 10-200-126	2,700.00 2,300.00	.00 2,600.00	450.00 3,450.00	3,150.00			
MVALDEZ - XMAS SAVINGS 10-200-127	900.00 600.00	.00 750.00	150.00 1,200.00	1,050.00			
HULL XMAS SAVINGS 10-200-128	.00 70.00	.00 250.00	.00 180.00	.00			
CHRISTMAS SAVINGS T GARCIA JR 10-200-129	1,800.00 100.00	.00 400.00	300.00 2,400.00	2,100.00			
CHRISTMAS SAVINGS ACC- ADAM Y 10-200-133	240.00 .00	.00 .00	120.00 360.00	360.00			
CHILD SUPPORT MANUEL PEREZ 10-200-134	.00 .00	1,264.14 3,371.04	1,264.14 3,371.04	.00			
AFLAC POST TAX PAYABLE 10-200-145	.00 .00	.00 52.20	.00 52.20	.00			
AFLAC PRE TAX PAYABLE 10-200-146	42.96 .00	257.04 3,588.21	227.04 3,601.17	12.96			

TRIAL BALANCE - ALL FUNDS
August 2024

Section 4, Item B.

B Future Period 08/2024

Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments			
					Debit	Dr-Rev	Credit	Cr-Rev
ACCRUED WAGES 10-200-190	23,507.91 23,507.91	.00 .00	.00 .00	23,507.91				
DUE TO COURT SECURITY 10-200-210	86.23 .00	.00 215.37	12.85 314.45	99.08				
DUE TO TECHNOLOGY 10-200-270	79.70 .00	.00 192.12	16.05 287.87	95.75				
DEFERRED REVENUES 10-200-310	8,401.59 8,401.59	.00 .00	.00 .00	8,401.59				
DUE TO WATER 10-200-405	125.00 .00	.00 .00	.00 125.00	125.00				
DUE TO WATER IMPACT FEES 10-200-407	316.32 .00	.00 5,000.00	.00 5,316.32	316.32				
DUE TO SEWER IMPACT FEES 10-200-408	32.43 .00	.00 .00	.00 32.43	32.43				
COLLECTIONS PAYABLE 10-210-120	14,289.09 2,968.09	.00 .00	921.67 12,242.67	15,210.76				
FICA PAYABLE 10-215-140	1,543.74 93.44	20,394.28 178,949.78	20,693.28 180,699.08	1,842.74				
MEDICAL PAYABLE 10-215-145	11,689.61 .00	16,929.87 178,774.97	17,803.71 191,338.42	12,563.45				
TMRS PAYABLE 10-215-155	28,246.59 16,900.30	25,100.30 159,758.03	17,176.12 163,180.14	20,322.41				
INCOME TAX PAYABLE 10-215-160	3,091.64 .00	8,985.23 88,204.39	9,535.27 91,846.07	3,641.68				
FUND BALANCE 10-270-000	1,224,714.05 1,224,714.05	.00 .00	.00 .00	1,224,714.05				
PARK/ BASEBALL DEPOSIT REFUND 10-400-200	-195.00 .00	650.00 2,220.00	700.00 2,075.00	-145.00				
XMAS SAVINGS - FELICIA CARVAJA 12-200-100	.00 100.00	.00 2,200.00	.00 2,100.00	.00				
ACCRUED WAGES 12-200-190	777.29 777.29	.00 .00	.00 .00	777.29				
FICA LIABILITY 12-215-140	-276.90 .00	886.44 6,015.88	886.44 5,738.98	-276.90				
MEDICAL PAYABLE 12-215-146	.10 .00	58.97 648.67	58.98 648.78	.11				
TMRS PAYABLE 12-215-155	-1,513.06 .00	1,213.22 5,477.79	315.74 3,067.25	-2,410.54				
FEDERAL TAX LIABILITY 12-215-160	.10 .00	427.64 2,388.07	417.64 2,378.17	-9.90				

TRIAL BALANCE - ALL FUNDS
August 2024

Section 4, Item B.

B Future period 07/2024

Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments			
					Debit	Dr-Rev	Credit	Cr-Rev
FUND BALANCE 12-270-000	2,238,499.74 2,238,499.74	.00 .00	.00 .00	2,238,499.74				
SALES TAX RECEIVABLE 14-110-430	-57,318.02 -57,318.02	.00 28,230.17	.00 28,230.17	-57,318.02				
ACCOUNTS PAYABLE 14-200-010	.00 .00	.00 554,143.47	.00 554,143.47	.00				
FUND BALANCE 14-270-000	797,605.53 797,605.53	.00 .00	.00 .00	797,605.53				
FUND BALANCE 15-270-000	143,072.86 143,072.86	.00 .00	.00 .00	143,072.86				
ACCOUNTS PAYABLE 16-200-010	.00 .00	.00 5,908.46	.00 5,908.46	.00				
FUND BALANCE 16-270-000	414.71 414.71	.00 .00	.00 .00	414.71				
ACCOUNTS PAYABLE 18-200-010	.00 .00	.00 40,735.10	.00 40,735.10	.00				
ACCOUNTS PAYABLE 25-200-010	.00 .00	.00 33,366.69	.00 33,366.69	.00				
FUND BALANCE 25-270-000	4,332.47 4,332.47	.00 .00	.00 .00	4,332.47				
FUND BALANCE 35-270-000	14,553.36 14,553.36	.00 .00	.00 .00	14,553.36				
PAYCLIX PAYMENTS 40-110-201	-82,041.12 .00	84,453.28 840,830.43	.00 674,336.03	-166,494.40				
ACCOUNTS PAYABLE 40-200-010	.00 106,994.50	109,707.03 1,446,474.61	109,707.03 1,339,480.11	.00				
DUE TO GENERAL FUND 40-200-020	104,219.61 48,549.78	.00 .00	9,221.30 64,891.13	113,440.91				
THELGESON XMAS 40-200-104	.00 150.00	.00 840.00	.00 690.00	.00				
ACCRUED WAGES 40-200-110	1,947.50 1,947.50	.00 .00	.00 .00	1,947.50				
JD- XMAS SAVINGS 40-200-119	440.00 280.00	.00 1,490.00	240.00 1,890.00	680.00				
AFLAC PAYABLE 40-200-125	.00 .00	239.67 1,917.36	239.67 1,917.36	.00				
FICA PAYABLE 40-200-140	-1,173.40 .00	2,028.90 16,544.02	1,729.90 15,071.62	-1,472.40				
MEDICAL PAYABLE 40-200-150	-7,614.96 .00	2,501.33 26,473.09	1,635.68 17,992.48	-8,480.61				

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Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
TMRS PAYABLE 40-200-155	-11,193.30 .00	6,974.72 31,061.52	3,442.44 16,335.94	-14,725.58			
INCOME TAX PAYABLE 40-200-160	-3,091.74 .00	1,289.19 10,655.78	749.15 7,024.00	-3,631.78			
OVERPAYMENT 40-200-200	15,684.61 15,684.61	.00 .00	.00 .00	15,684.61			
WATER DEPOSITS 40-200-210	100,213.48 100,213.48	.00 .00	.00 .00	100,213.48			
ACCRUED VACATION 40-200-220	7,321.04 7,321.04	.00 .00	.00 .00	7,321.04			
ACCRUED INTEREST PAYABLE 40-220-300	10,163.00 10,163.00	.00 .00	.00 .00	10,163.00			
BOND OUTSTANDING 40-250-100	2,265,000.00 2,265,000.00	.00 .00	.00 .00	2,265,000.00			
SARA LOAN 2005 (LT LIABILITY) 40-250-110	202,253.59 202,253.59	.00 .00	.00 .00	202,253.59			
CURRENT PORTION OF BONDS O/S 40-250-130	224,985.00 224,985.00	.00 .00	.00 .00	224,985.00			
CUR POTION OF BONDS O/S CONT 40-250-140	-224,985.00 -224,985.00	.00 .00	.00 .00	-224,985.00			
PREMIUM ON BONDS 40-250-150	113,360.00 113,360.00	.00 .00	.00 .00	113,360.00			
FUND BALANCE 40-270-000	-145,098.11 -145,098.11	.00 .00	.00 .00	-145,098.11			
REPAIR FUND 40-300-110	5,112.59 .00	.00 .00	.00 5,112.59	5,112.59			
INVESTED IN CAPITAL ASSETS 40-300-210	1,703,511.67 1,703,511.67	.00 .00	.00 .00	1,703,511.67			
FUND BALANCE 41-270-000	85.11 85.11	.00 .00	.00 .00	85.11			
DUE FROM GENERAL FUND 50-200-407	-316.32 .00	.00 316.32	.00 .00	-316.32			
FUND BALANCE 50-300-010	73,178.68 73,178.68	.00 .00	.00 .00	73,178.68			
DUE FROM GENERAL FUND 51-200-408	-32.43 .00	.00 32.43	.00 .00	-32.43			
FUND BALANCE 51-300-010	13,147.38 13,147.38	.00 .00	.00 .00	13,147.38			
* TOTAL LIABILITIES	8,849,068.34 8,961,838.17	342,529.52 4,749,485.99	258,207.37 4,552,394.01	8,764,746.19			

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					Debit	Dr-Rev	Credit Cr-Rev
R E V E N U E S							
AD VALORUM TAXES - CURRENT 10-400-010	287,394.39 .00	.00 .00	148.49 287,542.88	287,542.88			
AD VALORUM TAXES - DELINQUENT 10-400-015	894.45 .00	.00 29,233.67	.00 30,128.12	894.45			
AD VALORUM TAXES - ATT FEES 10-400-020	105.60 .00	.00 .00	.00 105.60	105.60			
AD VALORUM TAXES - PEN & INT 10-400-025	1,419.22 .00	.00 .00	.00 1,419.22	1,419.22			
BALL FIELD USAGE 10-400-049	475.00 .00	.00 57,080.00	.00 57,555.00	475.00			
PARK USE INCOME 10-400-050	7,984.63 .00	.00 .00	375.00 8,359.63	8,359.63			
FOOD LICENSE INCOME 10-400-060	18,575.00 .00	.00 .00	750.00 19,325.00	19,325.00			
PERMITS 10-400-065	408,687.34 .00	.00 .00	4,439.24 413,126.58	413,126.58			
VARIANCE, ZONING, SUP REQUEST 10-400-066	1,281.14 .00	.00 .00	.00 1,281.14	1,281.14			
CREDIT CARD REWARD REVENUE 10-400-070	19,994.58 .00	.00 .00	.00 19,994.58	19,994.58			
CONTRACTOR REGISTRATION 10-400-071	2,500.00 .00	.00 .00	200.00 2,700.00	2,700.00			
INTEREST INCOME 10-400-080	28,098.02 .00	.00 .00	.00 28,098.02	28,098.02			
MISC INCOME 10-400-095	308.39 .00	.00 .00	10.00 318.39	318.39			
OPIOID SETTLEMENT 10-400-096	-19.07 .00	.00 .00	.00 -19.07	-19.07			
STATE SALES TAX 10-400-110	980,384.96 .00	.00 .00	108,310.96 1,088,695.92	1,088,695.92			
PROPERTY RELEIF SALES TAX 10-400-115	209,808.55 .00	.00 .00	27,077.74 236,886.29	236,886.29			
MIXED BEVERAGE TAX 10-400-120	22,961.18 .00	.00 .00	2,074.95 25,036.13	25,036.13			
FRANCHISE TAX 10-400-150	86,217.25 .00	.00 .00	777.89 86,995.14	86,995.14			
AMERICAN TOWER LEASE 10-400-151	16,127.00 .00	.00 .00	.00 16,127.00	16,127.00			

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					Debit	Dr-Rev	Credit	Cr-Rev
CERTIFICATE OF OCCUPANCY 10-400-155	3,000.00 .00	.00 .00	250.00 3,250.00	3,250.00				
LITTLE LEAGUE ANNUAL FEES 10-400-156	28,540.00 .00	.00 28,540.00	.00 57,080.00	28,540.00				
LEOSE TRAINING INCOME 10-400-451	2,526.71 .00	.00 .00	.00 2,526.71	2,526.71				
PD NATIONAL NIGHT OUT 10-400-455	607.75 .00	.00 .00	.00 607.75	607.75				
PD GOLF TOURAMENT REVENUE 10-400-456	17,256.00 .00	.00 .00	.00 17,256.00	17,256.00				
MISC INCOME 10-410-285	1,705.00 .00	.00 .00	.00 1,705.00	1,705.00				
LVISD SRO OFFICER 10-410-286	274,127.48 .00	.00 .00	.00 274,127.48	274,127.48				
COPS LVISD 10-410-296	14,696.50 .00	.00 .00	.00 14,696.50	14,696.50				
LVISD ADMINISTRATION FEES 10-410-297	6,778.46 .00	.00 .00	.00 6,778.46	6,778.46				
POLICE REPORTS 10-410-298	264.00 .00	.00 4,338.50	42.00 4,644.50	306.00				
MDD OVERHEAD TRANSFER IN 10-410-300	60,000.00 .00	.00 .00	.00 60,000.00	60,000.00				
INDINGENT DEFENSE FUND (IDF) 10-415-315	90.95 .00	.00 .00	16.49 107.44	107.44				
LOCAL TRAFFIC FINE 10-415-320	696.06 .00	.00 .00	44.39 740.45	740.45				
LOCAL CONSOLIDATED COURT COST 10-415-321	459.84 .00	.00 .00	14.00 473.84	473.84				
MOVING VIOLATION FEE (MVF) 10-415-325	1.47 .00	.00 .00	.38 1.85	1.85				
STATE JURY FEE (JRF) 10-415-330	158.10 .00	.00 .00	32.97 191.07	191.07				
LOCAL JURY 10-415-331	24.02 .00	.00 .00	.10 24.12	24.12				
STATE JUDICIAL SUPPORT FUND (J) 10-415-335	236.86 .00	.00 .00	49.46 286.32	286.32				
STATE CONSOLIDATED COURT COST 10-415-340	-582.14 .00	.00 20,043.71	852.26 20,313.83	270.12				
STATE TRAFFIC FINE (STF) 10-415-345	10,424.02 .00	.00 .00	444.36 10,868.38	10,868.38				

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					Debit	Dr-Rev	Credit Cr-Rev
FINE 10-415-355	28,503.71 .00	.00 .00	1,585.90 30,089.61	30,089.61			
TIME PAYMENT FEE 10-415-360	198.38 .00	.00 .00	50.00 248.38	248.38			
WARRANT FEE 10-415-365	6,313.71 .00	.00 .00	326.74 6,640.45	6,640.45			
ADMINISTRATIVE FEE 10-415-370	610.00 .00	.00 .00	46.41 656.41	656.41			
DISMISSAL FEE 10-415-371	460.00 .00	.00 .00	.00 460.00	460.00			
ARREST FEE 10-415-372	1,594.20 .00	.00 .00	57.67 1,651.87	1,651.87			
OMNI COLLECTION FEE 10-415-380	1,810.71 .00	.00 .00	297.32 2,108.03	2,108.03			
DEFERRED FEE 10-415-385	8,945.75 .00	.00 .00	218.40 9,164.15	9,164.15			
SCHOOL ZONE VIOLATION FEE 10-415-391	1,027.90 .00	.00 .00	50.00 1,077.90	1,077.90			
TRUANCY PREVENTION FEE 10-415-392	1,342.82 .00	.00 .00	45.31 1,388.13	1,388.13			
SEATBELT FEE 10-415-393	-7,321.74 .00	.00 27,365.45	.00 20,043.71	-7,321.74			
RESTITUTION INCOME 10-415-395	200.00 .00	.00 .00	.00 200.00	200.00			
POLICE GOLF TOUR 10-520-286	.00 .00	.00 14,256.00	.00 14,256.00	.00			
2024 SERIES COO PROCEEDS 11-400-010	1,250,000.00 .00	.00 .00	.00 1,250,000.00	1,250,000.00			
BOND ADDITIONAL FEES 11-400-015	5,324.60 .00	.00 .00	.00 5,324.60	5,324.60			
INTEREST INCOME 11-400-080	12,653.23 .00	.00 .00	.00 12,653.23	12,653.23			
BANK INTEREST 12-400-080	19,256.91 .00	.00 19,214.76	.00 38,471.67	19,256.91			
MISC INCOME 12-400-095	494.95 .00	.00 .00	.00 494.95	494.95			
SALES TAX 12-400-110	478,437.14 .00	.00 .00	53,257.61 531,694.75	531,694.75			
EVENT VENDORS/DONATIONS 12-400-120	42,105.62 .00	.00 5,000.00	.00 47,105.62	42,105.62			

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					Debit	Dr-Rev	Credit	Cr-Rev
STREET MAINTENANCE TAX 14-400-010	238,038.72 .00	.00 .00	27,077.74 265,116.46	265,116.46				
INTEREST INCOME 14-400-080	9,422.85 .00	.00 .00	.00 9,422.85	9,422.85				
INTEREST INCOME 15-400-080	1,574.38 .00	.00 .00	.00 1,574.38	1,574.38				
HOTEL TAX REVENUE 15-400-100	51,982.90 .00	.00 6,287.18	5,333.61 63,603.69	57,316.51				
FORFEITURES 16-400-010	1,471.67 .00	.00 .00	.00 1,471.67	1,471.67				
INTEREST 16-400-080	23.60 .00	.00 .00	.00 23.60	23.60				
PD - AACOG BODY ARM GRANT REV 18-415-100	30,219.98 .00	.00 .00	.00 30,219.98	30,219.98				
INTEREST 25-400-080	4.48 .00	.00 .00	.00 4.48	4.48				
COURTHOUSE SECURITY FEES 25-410-210	1,365.83 .00	.00 .00	56.23 1,422.06	1,422.06				
INTEREST 35-400-080	145.21 .00	.00 .00	.00 145.21	145.21				
STATE COURT COST - TECH FEE 35-410-270	1,177.00 .00	.00 .00	58.68 1,235.68	1,235.68				
INTEREST INCOME 40-400-080	32.94 .00	.00 .00	.00 32.94	32.94				
NSF CHECK FEE 40-400-125	420.00 .00	.00 .00	120.00 540.00	540.00				
SALES TAX INCOME 40-400-505	22,383.73 .00	.00 .00	2,245.81 24,629.54	24,629.54				
WATER SALES 40-400-510	622,433.01 .00	.00 .00	73,336.50 695,769.51	695,769.51				
SEWER SALES 40-400-520	203,210.85 .00	.00 .00	20,394.67 223,605.52	223,605.52				
PENALTIES 40-400-530	7,737.63 .00	.00 .00	1,099.44 8,837.07	8,837.07				
METER TAMPERING FEE 40-400-535	75.00 .00	.00 .00	.00 75.00	75.00				
OPER & MAINTENANCE 40-400-540	26,437.05 .00	.00 .00	2,524.58 28,961.63	28,961.63				
GARBAGE SALES 40-400-550	340,020.83 .00	.00 .00	34,179.77 374,200.60	374,200.60				

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					Debit	Dr-Rev	Credit	Cr-Rev
OVERPAYMENT 40-400-555	5,730.31 .00	246.02 4,960.53	592.61 11,037.43	6,076.90				
NEW WATER METER FEES 40-400-560	3,432.00 .00	.00 .00	.00 3,432.00	3,432.00				
RECONNECTIONS 40-400-570	2,657.53 .00	.00 .00	238.08 2,895.61	2,895.61				
WATER DEPOSITS 40-400-590	15,074.41 .00	.00 .00	1,100.00 16,174.41	16,174.41				
ADMIN FEE 40-400-591	2,625.00 .00	.00 .00	175.00 2,800.00	2,800.00				
ADJUSTMENTS 40-400-595	654.00 .00	.00 94.10	257.70 1,005.80	911.70				
INTEREST INCOME 41-400-080	.52 .00	.00 .00	.00 .52	.52				
INTEREST INCOME 50-400-080	707.15 .00	.00 .00	.00 707.15	707.15				
WATER IMPACT FEES 50-400-585	1,739.76 .00	.00 .00	.00 1,739.76	1,739.76				
INTEREST INCOME 51-400-080	127.05 .00	.00 .00	.00 127.05	127.05				
SEWER IMPACT FEES 51-400-580	324.30 .00	.00 .00	.00 324.30	324.30				
* TOTAL REVENUES	5,957,416.29 .00	246.02 216,413.90	370,636.46 6,544,220.63	6,327,806.73				
E X P E N S E S								
OFFICE SUPPLIES 10-500-220	.00 .00	.00 22.55	.00 22.55	.00				
DUES AND SUBSCRIPTIONS 10-500-230	.00 .00	.00 100.00	.00 100.00	.00				
UNIFORMS 10-500-250	39.94 .00	.00 139.94	.00 100.00	39.94				
TECHNOLOGY/SOFTWARE UPGRADES 10-500-270	.00 .00	4,500.00 4,500.00	.00 .00	4,500.00				
CONTRACT SERVICES - BV 10-500-300	25,068.35 .00	.00 25,068.35	.00 .00	25,068.35				
FIRE INSPECTIONS SERVICES 10-500-301	9,000.00 .00	.00 12,000.00	.00 3,000.00	9,000.00				

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					Debit	Dr-Rev	Credit Cr-Rev
WORKERS COMP INSURANCE 10-500-320	457.00 .00	.00 457.00	.00 .00	457.00			
LEGAL & PROFESSIONAL - ENGINEE 10-500-410	15,842.50 .00	.00 15,842.50	.00 .00	15,842.50			
MUNI CODES 10-500-425	354.00 .00	1,787.52 2,141.52	.00 .00	2,141.52			
EMPLOYEE TRAINING 10-500-450	75.00 .00	.00 75.00	.00 .00	75.00			
WAGES - GENERAL 10-510-010	144,005.06 .00	16,200.04 160,205.10	.00 .00	160,205.10			
OVERTIME 10-510-015	59.49 .00	118.98 213.21	.00 34.74	178.47			
CAR/ PHONE ALLOWANCE 10-510-020	4,823.15 .00	.00 4,823.15	.00 .00	4,823.15			
PAYROLL TAXES 10-510-110	11,251.28 .00	1,218.34 12,469.62	.00 .00	12,469.62			
TMRS 10-510-115	7,853.44 .00	889.39 8,742.83	.00 .00	8,742.83			
EMPLOYEE INSURANCE 10-510-150	23,100.62 .00	2,738.77 25,839.39	.00 .00	25,839.39			
OFFICE EXPENSE 10-510-210	2,207.08 .00	.00 2,207.08	.00 .00	2,207.08			
OFFICE EQUIPMENT RENTALS 10-510-212	7,210.76 .00	425.00 7,635.76	.00 .00	7,635.76			
BUILDING EXPENSE - CH 10-510-214	33,648.51 .00	.00 33,648.51	.00 .00	33,648.51			
OFFICE CLEANING 10-510-215	5,250.00 .00	500.00 5,750.00	.00 .00	5,750.00			
OFFICE SUPPLIES 10-510-220	3,132.94 .00	.00 3,132.94	.00 .00	3,132.94			
DUES AND SUBSCRIPTIONS 10-510-230	1,325.90 .00	.00 1,325.90	.00 .00	1,325.90			
TELEPHONE 10-510-240	6,774.99 .00	.00 6,774.99	.00 .00	6,774.99			
UNIFORMS 10-510-250	56.88 .00	.00 56.88	.00 .00	56.88			
POSTAGE 10-510-260	1,101.90 .00	.00 1,101.90	.00 .00	1,101.90			
TECHNOWLEDGE/SOFTWARE UPGRADES 10-510-270	55,502.90 .00	509.60 56,012.50	.00 .00	56,012.50			

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					Debit	Dr-Rev	Credit	Cr-Rev
UTILITIES 10-510-290	7,471.04 .00	.00 8,495.02	.00 1,023.98	7,471.04				
NATIONAL NIGHT EXPENSES 10-510-300	883.63 .00	.00 883.63	.00 .00	883.63				
PROPERTY & LIABILITY INSURANCE 10-510-310	16,699.92 .00	.00 16,699.92	.00 .00	16,699.92				
WORKERS COMP INSURANCE 10-510-320	315.18 .00	.00 315.18	.00 .00	315.18				
LEGAL & PROFESSIONAL - LEGAL 10-510-420	12,655.40 .00	2,608.06 15,263.46	.00 .00	15,263.46				
LEGAL & PROFESSIONAL - COLLECT 10-510-421	7,571.93 .00	.00 7,571.93	.00 .00	7,571.93				
FOOD LICENSE EXPENSE 10-510-435	4,450.00 .00	950.00 5,400.00	.00 .00	5,400.00				
EMPLOYEE TRAINING 10-510-450	5,183.28 .00	9,866.65 15,049.93	.00 .00	15,049.93				
WCAC QUARTERLY PAYMENT 10-510-452	5,666.18 .00	.00 5,666.18	.00 .00	5,666.18				
AUDIT EXPENSE 10-510-460	9,350.00 .00	.00 9,350.00	.00 .00	9,350.00				
ELECTION EXPENSE 10-510-465	675.00 .00	270.00 945.00	.00 .00	945.00				
BANK SERVICE CHARGES 10-510-470	1,534.61 .00	.00 1,534.61	.00 .00	1,534.61				
ADS 10-510-490	662.52 .00	.00 662.52	.00 .00	662.52				
LIBRARY DONATION 10-510-700	156.00 .00	.00 2,696.00	.00 2,540.00	156.00				
CHILD ADVOCACY 10-510-710	5,000.00 .00	.00 5,000.00	.00 .00	5,000.00				
ANIMAL CONTROL CONTRACT 10-510-720	5,000.00 .00	.00 5,000.00	.00 .00	5,000.00				
MISCELLANEOUS EXPENSE 10-510-920	3,935.81 .00	193.38 5,338.82	.00 1,209.63	4,129.19				
WAGES - COURT 10-515-010	36,675.34 .00	3,125.76 39,801.10	.00 .00	39,801.10				
PAYROLL TAXES 10-515-110	2,790.39 .00	254.43 3,044.82	.00 .00	3,044.82				
TMRS 10-515-115	1,610.60 .00	45.88 1,656.48	.00 .00	1,656.48				

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Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
EMPLOYEE INSURANCE 10-515-150	101.34 .00	.00 101.34	.00 .00	101.34			
OFFICE EXPENSE 10-515-210	41.60 .00	.00 41.60	.00 .00	41.60			
TECHNOLOGY/SOFTWARE UPGRADES 10-515-271	8,600.00 .00	260.00 8,860.00	.00 .00	8,860.00			
WORKERS COMP INSURANCE 10-515-320	70.34 .00	.00 70.34	.00 .00	70.34			
PROSECUTOR SERVICES 10-515-415	400.00 .00	200.00 600.00	.00 .00	600.00			
JURY EXPENSE 10-515-420	-1.26 .00	.00 12.56	.54 14.36	-1.80			
EMPLOYEE TRAINING 10-515-450	877.30 .00	.00 877.30	.00 .00	877.30			
OMNI COLLECTION 10-515-474	810.00 .00	.00 810.00	.00 .00	810.00			
STATE COURT COSTS 10-515-550	.00 .00	.00 7,918.40	.00 7,918.40	.00			
WAGES - POLICE 10-520-010	668,972.22 .00	91,195.24 760,167.46	.00 .00	760,167.46			
CONTRACT LABOR 10-520-011	17,762.50 .00	650.00 18,412.50	.00 .00	18,412.50			
SHIFT DIFFERENTIAL 10-520-012	5,025.00 .00	775.00 5,800.00	.00 .00	5,800.00			
OVERTIME 10-520-015	21,006.97 .00	315.84 21,548.70	.00 225.89	21,322.81			
PAYROLL TAXES 10-520-110	51,891.31 .00	6,937.40 58,828.71	.00 .00	58,828.71			
TMRS 10-520-115	37,888.08 .00	5,029.62 42,917.70	.00 .00	42,917.70			
EMPLOYEE INSURANCE 10-520-150	113,673.76 .00	9,696.46 123,370.22	.00 .00	123,370.22			
MEDICAL COST 10-520-160	1,465.41 .00	75.00 1,540.41	.00 .00	1,540.41			
OFFICE EXPENSE 10-520-210	999.68 .00	.00 999.68	.00 .00	999.68			
OFFICE SUPPLIES 10-520-220	1,405.84 .00	.00 1,405.84	.00 .00	1,405.84			
TELEPHONE 10-520-240	13,255.87 .00	.00 13,255.87	.00 .00	13,255.87			

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Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
UNIFORMS 10-520-250	15,112.77 .00	461.96 15,574.73	.00 .00	15,574.73			
TECHNOLOGY/SOFTWARE UPGRADES 10-520-270	27,392.00 .00	243.75 27,635.75	.00 .00	27,635.75			
POLICE GOLF TOURNAMENT 10-520-287	15,499.91 .00	.00 15,499.91	.00 .00	15,499.91			
PROPERTY & LIABILITY INSURANCE 10-520-310	15,656.17 .00	.00 15,656.17	.00 .00	15,656.17			
WORKERS COMP INSURANCE 10-520-320	23,105.37 .00	.00 23,105.37	.00 .00	23,105.37			
UNEMPLOYMENT TWC 10-520-325	-2,308.00 .00	.00 .00	.00 2,308.00	-2,308.00			
EMPLOYEE TRAINING 10-520-450	11,921.40 .00	.00 11,921.40	.00 .00	11,921.40			
LEOSE TRAINING EXPENSE 10-520-451	395.00 .00	.00 1,632.24	.00 1,237.24	395.00			
CONTRACT SERVICES CAMERA 10-520-476	16,300.00 .00	.00 16,300.00	.00 .00	16,300.00			
K-9 CONTRACT LABOR 10-520-478	1,816.43 .00	558.52 2,374.95	.00 .00	2,374.95			
COPS LVIDS CONTRACT PAY 10-520-479	17,936.10 .00	.00 17,936.10	.00 .00	17,936.10			
EVIDENCE SUPPLIES 10-520-480	1,240.35 .00	.00 1,240.35	.00 .00	1,240.35			
ADS 10-520-490	.00 .00	.00 37.10	.00 37.10	.00			
ADS - PUBLICATIONS 10-520-499	45.00 .00	.00 45.00	.00 .00	45.00			
VEHICLE PURCHASE 10-520-600	3,517.00 .00	.00 3,517.00	.00 .00	3,517.00			
VEHICLE FUEL 10-520-610	34,156.07 .00	6,038.40 40,194.47	.00 .00	40,194.47			
VEHICLE REPAIR 10-520-620	35,836.57 .00	1,178.00 37,014.57	858.09 858.09	36,156.48			
GENERAL SUPPLIES 10-520-670	2,170.36 .00	.00 2,170.36	.00 .00	2,170.36			
EQUIPMENT PURCHASES 10-520-690	12,114.70 .00	.00 12,114.70	.00 .00	12,114.70			
WCSO DISPATCH 10-520-910	3,000.00 .00	.00 3,000.00	.00 .00	3,000.00			

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Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
MICELLAENOUS 10-520-920	4,840.11 .00	500.00 5,340.11	.00 .00	5,340.11			
WAGES - PUBLIC WORKS 10-530-010	64,004.32 .00	8,786.40 72,790.72	.00 .00	72,790.72			
OVERTIME 10-530-015	3,178.72 .00	352.08 3,530.80	.00 .00	3,530.80			
PAYROLL TAXES 10-530-110	5,088.37 .00	701.40 5,789.77	.00 .00	5,789.77			
TMRS 10-530-115	3,142.63 .00	223.02 3,365.65	.00 .00	3,365.65			
EMPLOYEE INSURANCE 10-530-150	9,846.62 .00	405.12 10,251.74	.00 .00	10,251.74			
TELEPHONE 10-530-240	2,633.09 .00	.00 2,633.09	.00 .00	2,633.09			
UNIFORMS 10-530-250	3,167.72 .00	.00 3,167.72	.00 .00	3,167.72			
PROPERTY & LIABILITY INSURANCE 10-530-310	9,393.70 .00	.00 9,393.70	.00 .00	9,393.70			
WORKERS COMP INSURANCE 10-530-320	1,043.75 .00	.00 1,043.75	.00 .00	1,043.75			
VEHICLE FUEL 10-530-610	16,747.38 .00	2,012.99 18,760.37	.00 .00	18,760.37			
VEHICLE REPAIR 10-530-620	106.79 .00	.00 712.03	.00 605.24	106.79			
REPAIR AND MAINTENANCE 10-530-655	205.21 .00	50.74 255.95	.00 .00	255.95			
TOOLS 10-530-660	1,106.59 .00	.00 1,106.59	.00 .00	1,106.59			
STREET REPAIR 10-530-665	7,558.31 .00	1,253.00 8,811.31	.00 .00	8,811.31			
EQUIPMENT 10-530-690	360.50 .00	.00 360.50	.00 .00	360.50			
EQUIPMENT - BIG ITEMS 10-530-791	3,516.00 .00	.00 3,516.00	.00 .00	3,516.00			
ENGINEERING FEES 10-530-930	.00 .00	5,750.00 22,581.25	.00 16,831.25	5,750.00			
WAGES - PARK DEPARTMENT 10-580-010	62,899.37 .00	8,733.60 71,632.97	.00 .00	71,632.97			
OVERTIME 10-580-015	4,785.80 .00	.00 4,785.80	.00 .00	4,785.80			

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Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments			
					Debit	Dr-Rev	Credit	Cr-Rev
PAYROLL TAXES 10-580-110	5,203.23 .00	670.45 5,873.68	.00 .00	5,873.68				
TMRS 10-580-115	4,207.68 .00	751.02 4,958.70	.00 .00	4,958.70				
EMPLOYEE INSURANCE 10-580-150	18,080.82 .00	2,321.70 20,402.52	.00 .00	20,402.52				
TELEPHONE 10-580-240	788.17 .00	.00 788.17	.00 .00	788.17				
UNIFORMS 10-580-250	1,758.49 .00	.00 1,758.49	.00 .00	1,758.49				
UTILITIES - PARK 10-580-290	8,848.82 .00	.00 9,864.06	.00 1,015.24	8,848.82				
PROPERTY & LIABILITY INSURANCE 10-580-310	5,218.73 .00	.00 5,218.73	.00 .00	5,218.73				
WORKERS COMP INSURANCE 10-580-320	257.41 .00	.00 257.41	.00 .00	257.41				
VEHICLE PURCHASE 10-580-600	209.96 .00	.00 209.96	.00 .00	209.96				
VEHICLE FUEL 10-580-610	4,465.83 .00	613.79 5,079.62	.00 .00	5,079.62				
VEHICLE REPAIR 10-580-620	7,207.40 .00	.00 7,207.40	.00 .00	7,207.40				
REPAIR AND MAINTENANCE 10-580-655	3,000.76 .00	.00 164,908.76	.00 161,908.00	3,000.76				
CITY PARK SUPPLIES 10-580-670	5,853.23 .00	.00 5,853.23	.00 .00	5,853.23				
PARK EQUIPMENT 10-580-690	7,505.09 .00	.00 7,505.09	.00 .00	7,505.09				
DRAINAGE PROJECT 11-500-100	48,400.00 .00	.00 48,400.00	.00 .00	48,400.00				
ENGINEERING FEE 11-510-100	988.75 .00	.00 988.75	.00 .00	988.75				
WAGES - MDD 12-500-010	31,715.68 .00	5,793.64 37,509.32	.00 .00	37,509.32				
PAYROLL TAXES 12-500-050	2,426.27 .00	443.22 2,869.49	.00 .00	2,869.49				
TMRS 12-500-115	1,728.55 .00	315.74 2,044.29	.00 .00	2,044.29				
EMPLOYEE INSURANCE 12-500-150	589.80 .00	58.98 648.78	.00 .00	648.78				

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Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
OFFICE SUPPLIES 12-500-220	4,484.86 .00	117.86 4,602.72	.00 .00	4,602.72			
MEMBERSHIP/DUES 12-500-230	304.49 .00	.00 304.49	.00 .00	304.49			
NEWS PUBLICATIONS/SUBSCRIPTION 12-500-231	1,244.00 .00	.00 1,244.00	.00 .00	1,244.00			
TELEPHONE 12-500-240	420.32 .00	.00 420.32	.00 .00	420.32			
WORKERS COMP INSURANCE 12-500-320	67.80 .00	.00 67.80	.00 .00	67.80			
FACILITY & OVERHEAD COST TO GF 12-500-400	60,000.00 .00	.00 60,000.00	.00 .00	60,000.00			
ENGINEERING 12-500-410	545.00 .00	.00 545.00	.00 .00	545.00			
LEGAL 12-500-420	42.00 .00	44.00 86.00	.00 .00	86.00			
TRAINING/CONFERENCE/TRAVEL 12-500-450	1,513.36 .00	.00 1,513.36	.00 .00	1,513.36			
ECONOMIC DEVELOPMENT 12-500-456	5,000.00 .00	.00 7,479.50	.00 2,479.50	5,000.00			
EVENT PLANNING 12-500-460	221,934.08 .00	.00 221,934.08	.00 .00	221,934.08			
CONSULTING/PLANNING 12-500-475	162,208.00 .00	.00 162,208.00	.00 .00	162,208.00			
ADVERTISING 12-500-476	-50.00 .00	.00 -50.00	.00 .00	-50.00			
FACADE/BEAR GRANTS 12-500-477	9,371.04 .00	.00 9,371.04	.00 .00	9,371.04			
TRAFFIC STUDY 12-500-478	3,860.00 .00	.00 3,860.00	.00 .00	3,860.00			
STREET REPAIR 14-500-100	531,797.42 .00	.00 531,797.42	.00 .00	531,797.42			
PROFESSIONAL - ENGINEERING 14-500-410	22,346.05 .00	.00 22,346.05	.00 .00	22,346.05			
PD/FIRE RADIO GRANT 18-517-100	53.00 .00	.00 53.00	.00 .00	53.00			
ACOG 2023 GRANT PD 18-570-100	40,682.10 .00	.00 40,682.10	.00 .00	40,682.10			
BUILDING SECURITY 25-500-200	5,366.69 .00	.00 33,366.69	.00 28,000.00	5,366.69			

TRIAL BALANCE - ALL FUNDS
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Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
WAGES 40-540-010	127,039.85 .00	17,530.68 144,570.53	.00 .00	144,570.53			
OVERTIME 40-540-015	10,869.25 .00	1,297.06 12,166.31	.00 .00	12,166.31			
PAYROLL TAXES 40-540-110	10,449.18 .00	1,429.57 11,878.75	.00 .00	11,878.75			
TMRS 40-540-115	7,516.05 .00	1,026.13 8,542.18	.00 .00	8,542.18			
ON CALL PAY 40-540-120	1,500.00 .00	210.00 1,710.00	.00 .00	1,710.00			
EMPLOYEE INSURANCE 40-540-150	24,786.95 .00	2,458.44 27,245.39	.00 .00	27,245.39			
OFFICE EXPENSE 40-540-210	185.44 .00	1,674.00 1,859.44	.00 .00	1,859.44			
DUES AND SUBSCRIPTIONS 40-540-230	1,803.75 .00	.00 1,803.75	.00 .00	1,803.75			
TELEPHONE 40-540-240	4,036.54 .00	419.13 4,455.67	.00 .00	4,455.67			
POSTAGE 40-540-260	2,370.38 .00	800.00 3,170.38	.00 .00	3,170.38			
DEPOSIT REFUND 40-540-281	6,272.12 .00	134.73 6,406.85	.00 .00	6,406.85			
APPLIED DEPOSIT REIMBURSEMENT 40-540-284	6,843.00 .00	565.27 7,408.27	.00 .00	7,408.27			
UTILITIES 40-540-290	80,799.47 .00	.00 87,502.47	.00 6,703.00	80,799.47			
PROPERTY & LIABILITY INSURANCE 40-540-310	10,124.32 .00	.00 10,124.32	.00 .00	10,124.32			
WORKERS COMP INSURANCE 40-540-320	1,253.15 .00	.00 1,253.15	.00 .00	1,253.15			
PERMITS & INSPECTIONS 40-540-411	6,523.78 .00	.00 6,523.78	.00 .00	6,523.78			
EMPLOYEE TRAINING & LICENSING 40-540-450	2,311.98 .00	.00 2,311.98	.00 .00	2,311.98			
AUDIT EXPENSE 40-540-460	9,350.00 .00	.00 9,350.00	.00 .00	9,350.00			
PAYCLIX EXPENSE 40-540-471	12,344.08 .00	.00 12,344.08	.00 .00	12,344.08			
VEHICLE FUEL 40-540-610	20.00 .00	.00 20.00	.00 .00	20.00			

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Account Title Number	Beg-Bal-Mo Beg-Bal-Yr	Debits/MTD Debits/YTD	Credits/MTD Credits/YTD	Ending Balance	Adjustments		
					Debit	Dr-Rev	Credit Cr-Rev
VEHICLE REPAIR 40-540-620	43,282.93 .00	43.38 43,326.31	.00 .00	43,326.31			
GARBAGE COLLECTION EXPENSE 40-540-710	315,497.66 .00	.00 315,497.66	.00 .00	315,497.66			
SALES TAX EXPENSE 40-540-720	22,389.46 .00	2,218.99 24,608.45	.00 .00	24,608.45			
SUPPLIES AND REPAIRS 40-540-810	115,892.65 .00	9,941.74 125,834.39	.00 .00	125,834.39			
WWTP OPERATION 40-540-820	297,348.06 .00	7,075.00 336,395.04	.00 31,971.98	304,423.06			
METER REPLACEMENT 40-540-825	.00 .00	13,132.12 13,132.12	.00 .00	13,132.12			
WATER ANALYSIS LAB 40-540-830	7,713.00 .00	1,044.00 8,757.00	.00 .00	8,757.00			
CHEMICALS 40-540-840	20,084.68 .00	2,419.22 22,503.90	.00 .00	22,503.90			
BULK WATER PURCHASE 40-540-880	50,806.80 .00	14,661.20 65,468.00	.00 .00	65,468.00			
WELL PROJECTS 40-540-901	5,820.00 .00	1,455.00 7,275.00	.00 .00	7,275.00			
LAND LEASE 40-540-902	14,578.00 .00	.00 14,578.00	.00 .00	14,578.00			
EQUIPMENT PURCHASE 40-540-906	697.82 .00	.00 697.82	.00 .00	697.82			
C OF O 2011 PRINCIPAL 40-540-909	48,000.00 .00	.00 48,000.00	.00 .00	48,000.00			
SARA LOAN PRINCIPAL 40-540-910	.00 .00	36,984.86 36,984.86	.00 .00	36,984.86			
C OF O 2011 INTEREST 40-540-912	4,513.77 .00	4,009.77 8,523.54	.00 .00	8,523.54			
SARA LOAN INTEREST 40-540-913	.00 .00	9,060.92 9,060.92	.00 .00	9,060.92			
2016 SERIES - INTEREST PAYMENT 40-540-917	43,125.00 .00	.00 43,125.00	.00 .00	43,125.00			
2016 SERIES BOND - ADMIN FEE 40-540-918	200.00 .00	.00 200.00	.00 .00	200.00			
MISCELLANEOUS EXPENSE 40-540-920	.00 .00	400.00 400.00	.00 .00	400.00			
* TOTAL EXPENSES	4,415,200.66 .00	339,706.95 5,024,193.17	858.63 270,144.19	4,754,048.98			

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Account Title Number	Beg-Bal-Mo	Debits/MTD	Credits/MTD	Ending Balance	Adjustments		
	Beg-Bal-Yr	Debits/YTD	Credits/YTD		Debit	Dr-Rev	Credit Cr-Rev
*** GRAND TOTALS	-176,208.20 .00	996,235.87 18,717,820.46	996,235.87 18,541,612.26	-176,208.20	_____	_____	_____



A Proclamation by the Mayor

WHEREAS, the National Association of Town Watch is sponsoring a unique, nationwide crime, drug, and violence prevention program on October 1st entitled “National Night Out”; and

WHEREAS, the 41st Annual National Night Out provides a unique opportunity for La Vernia and Wilson County to join forces with thousands of other communities across the country in promoting cooperative, police-community crime prevention efforts; and

WHEREAS, La Vernia Police Department and La Vernia Fire Department, through joint crime, drug, and violence prevention and fire prevention efforts in La Vernia and Wilson County, are supporting National Night Out 2024 locally; and

WHEREAS, it is essential that all citizens of La Vernia be aware of the importance of crime prevention programs and the impact that their participation can have on reducing crime, drugs, and violence in La Vernia; and

WHEREAS, police-community partnerships, neighborhood safety, awareness, and cooperation are essential themes of the “National Night Out” program,

NOW, THEREFORE, I, MARTIN POORE, MAYOR, AND THE CITY COUNCIL OF LA VERNIA, do hereby call on all the citizens of La Vernia and Wilson County to join the Police Department, the Fire Department, and the National Association of Town Watch in supporting the 41st Annual National Night Out on October 1st, 2024. I hereby proclaim Tuesday, October 1st, 2024, as “NATIONAL NIGHT OUT” in La Vernia.

In Witness Whereof, I have hereunto set my hand and caused the Great Seal of the City of La Vernia, Texas, to be affixed at City Hall in La Vernia this 5th day of September, 2024.

Mayor

City Secretary

RESOLUTION R090524-01

**A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF LA
VERNIA, TEXAS, ADOPTING A BUDGET POLICY; ESTABLISHING AN
EFFECTIVE DATE**

WHEREAS, Per Local Government code, title 4. Finances, Subtitle A. Municipal Finances, Chapter 102. Municipal Budget, Sec. 102.002. Annual Budget Required states that the budget officer of a municipality shall prepare a municipal budget each year to cover the proposed expenditures of the municipal government for the succeeding year; and

WHEREAS, The City of La Vernia (“City”) considers the expenditure of funds to be an essential responsibility; and

WHEREAS, The city wishes to establish parameters pertaining to budgeting in order to exercise sound judgment in spending taxpayer’s money; and

WHEREAS, It is the policy of the City to produce all budget documents in the highest ethical manner and in accordance with all applicable laws and regulations; and

WHEREAS, To the extent required by law and regulation, and the maximum extent practical, the City will conduct all budgeting procedures in a manner that provides full and open transparency.

**NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF LA
VERNIA, TEXAS:**

SECTION 1. That the Budget Policy, attached hereto as “Exhibit A”, is hereby adopted as the official Budget Policy of the City.

SECTION 2. To the extent that any budgeting was initiated under a previous budget policy of the City, that policy shall remain in effect only for the purposes of that or those particular fiscal years.

SECTION 3. That the City Administrator is hereby authorized to implement the Budget Policy attached as Exhibit A.

SECTION 4. All resolutions, or parts thereof, which are in conflict or inconsistent with any provision of this Resolution are hereby repealed to the extent of such conflict, and the provisions of this Resolution shall be and remain controlling as to the matters resolved herein.

SECTION 5. It is officially found, determined, and declared that the meeting at which this Resolution is adopted was open to the public and public notice of the time, place, and

subject matter of the public business to be considered at such meeting, including this Resolution, was given, all as required by Chapter 551, Texas Government Code, as amended.

SECTION 6. This Resolution shall be in force and effect from and after its final passage, and it is so resolved.

PASSED AND APPROVED this 05th day of Sept 2024.

Martin Poore, Mayor

ATTEST:

Madison Farrow, City Secretary

APPROVED AS TO FORM:

City Attorney's Office

Exhibit A



Budget Policy

PURPOSE

The following policies outline the City of La Vernia's (the "City") guidelines for budgetary decision-making and set standards for sound budgetary practices and fiscal performance. Adhering to these budget policies will assist the City in achieving its current and future goals in a fiscally responsible and sustainable manner.

SCOPE

This policy encompasses budgeting for operating and capital projects, revenue management, forecasting, internal controls, and reporting.

OBJECTIVES

These policies serve to guide the development of the City's budget and establish standards for revenue generation and the execution of operating expenditures, as recommended by the Government Finance Officers Association (GFOA). The budget policies are designed to manage financial pressures in response to growing demands on City resources while ensuring long-term fiscal stability.

BUDGET PROCESS

The purpose of the budget process is to help decision-makers make prudent choices regarding the provision of services and capital assets and to encourage stakeholder participation. The following summarizes the policies that will guide this process:

1. At the beginning of each budget cycle, the City Administrator and City Council will set parameters and priorities.
2. The City Administrator and Finance Administrator will annually publish a Budget Preparation Manual to guide departments in developing their budgets.
3. The budget process will include a five-year financial forecast to assess the long-term financial implications of current and proposed policies, programs, and assumptions and develop appropriate strategies to achieve the City Council's goals.

4. After departmental requests are submitted, the City Administrator will review and evaluate all baseline budget requests to ensure they meet City Council goals and objectives, improve management effectiveness, and enhance service delivery.
5. The City Administrator will submit a Proposed Budget to the City Council for approval. This submission will include the City Administrator's Budget Message, a concise summary of the budget, which shall include:
 - o A summary of significant changes in priorities or service levels from the current year and the factors leading to those changes.
 - o The priorities and critical issues for the new budget period.
 - o Identification and summary of major financial factors and trends affecting the budget, such as economic factors, long-range outlook, significant changes in revenue collections, tax rates, current and future debt obligations, and significant use or increase in unreserved fund balance.
 - o Financial summary data on revenues, other resources, and expenditures for at least a five-year period, including prior year actuals, current year budget and/or estimated current year actuals, and the proposed budget.

BALANCED BUDGET

The general fund, which is the primary operating fund of the City, is required to have a balanced budget annually. The City's goal is to balance the operating budget with current revenues, meaning that current revenues should match and fund ongoing expenditures and expenses. The budget is considered balanced when total spending and costs are equal to total revenues. Additionally, the budget is considered balanced when total spending and costs are less than total revenues, resulting in a surplus. There may be instances where the City plans to use excess fund balances accumulated from previous years (while maintaining established reserves) for one-time or non-routine expenditures. The budget is deemed balanced in this case as long as the funding from previous years is available and a plan is in place to ensure that ongoing expenditures are not funded from this type of funding. This type of balanced budget is especially relevant when capital projects are funded through bond issuance.

BUDGET ADOPTION

The budget shall be adopted by resolution no later than the day before the first day of the City's fiscal and budget year. If the budget is not adopted by this deadline, the appropriation for personnel and essential operating supplies made in the previous year shall be extended until the new budget is adopted.

BUDGET CONTROLS AND ACCOUNTABILITY

Each department director, appointed by the City Administrator, will be responsible for the strategic plan and goals adopted by the City Council as part of the budget and for monitoring their individual departmental budget to ensure compliance with spending limitations.

The Finance Administrator, at the direction of the City Administrator, may transfer funds within the line items of a departmental budget category. All other transfers of appropriation or budget amendments that alter the originally adopted budgets at the fund level require approval from the City Administrator and City Council, as outlined in the following section.

AMENDMENTS TO THE BUDGET

Before Adoption:

After the public hearing, the City Council may adopt the budget with or without amendments. In amending the proposed budget, the City Council may add or increase programs or amounts and may delete or decrease any programs or amounts, except for expenditures required by law or for debt service. However, no amendment to the proposed budget shall increase spending to an amount greater than the estimated income (including the use of available Fund Balance).

After Adoption:

- a. Department Heads are authorized to request budget transfers.
- b. A budget transfer of personal services appropriations or affecting revenue accounts requires the approval of the City Administrator or his/her designee.
- c. A budget transfer must be approved prior to the occurrence of the expenditure, except for emergency expenditures, which must be approved by the City Administrator or his/her designee and ratified by the City Council.
- d. The City Administrator shall have the authority to establish the budget for any capital projects that the City Council approves.
- e. Budget amendments submitted to the City Council shall be accompanied by an explanation from the department and a recommendation from the City Administrator or his/her designee. The department’s reason must be sufficiently clear and detailed to allow City Council members to determine the necessity of the amendments.
- f. The City Administrator or his/her designee is authorized to establish budgets and staffing changes for grants and similar awards when the City Council and City Administrator have previously approved the applications for such grants and awards.

[Approved September 05, 2024, by the La Vernia City Council, Resolution #_____]

RESOLUTION R090524-02

A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF LA VERNIA, TEXAS, ADOPTING A FUND POLICY; ESTABLISHING AN EFFECTIVE DATE

WHEREAS, Per Local Government Code, Title 4. Finances, Subtitle A. Municipal Finances, Chapter 101. General Financial Provisions Affecting Municipalities, Subchapter A. Provisions Affecting Type a General-Law Municipalities, Sec. 101.002. Control of Finances states that the governing body of the municipality may manage and control the finances of the municipality; and

WHEREAS, The City of La Vernia (“City”) considers the expenditure of funds to be an essential responsibility; and

WHEREAS, The city wishes to establish parameters pertaining to the fund balance of its varied funds in order to exercise sound judgment in spending taxpayer’s money; and

WHEREAS, It is the policy of the City to manage all funds in the highest ethical manner and in accordance with all applicable laws and regulations; and

WHEREAS, To the extent required by law and regulation, and the maximum extent practical, the City will conduct all matters related to funding sources in a manner that provides full and open transparency.

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF LA VERNIA, TEXAS:

SECTION 1. That the Fund Policy, attached hereto as “Exhibit A”, is hereby adopted as the official Fund Policy of the City.

SECTION 2. To the extent that any budgeting was initiated under a previous budget policy of the City, that policy shall remain in effect only for the purposes of that or those particular fiscal years.

SECTION 3. That the City Administrator is hereby authorized to implement the Fund Policy attached as Exhibit A.

SECTION 4. All resolutions, or parts thereof, which are in conflict or inconsistent with any provision of this Resolution are hereby repealed to the extent of such conflict, and the provisions of this Resolution shall be and remain controlling as to the matters resolved herein.

SECTION 5. It is officially found, determined, and declared that the meeting at which this Resolution is adopted was open to the public and public notice of the time, place, and

subject matter of the public business to be considered at such meeting, including this Resolution, was given, all as required by Chapter 551, Texas Government Code, as amended.

SECTION 6. This Resolution shall be in force and effect from and after its final passage, and it is so resolved.

PASSED AND APPROVED this 05th day of Sept 2024.

Martin Poore, Mayor

ATTEST:

Madison Farrow, City Secretary

APPROVED AS TO FORM:

City Attorney's Office

Exhibit A



Fund Balance Policy (per GASB 54)

PURPOSE

The purpose of this policy is to establish a key element of the financial stability of the City of La Vernia (the City), setting guidelines for fund balance. Unassigned fund balance is an important measure of economic stability. It is essential that the City maintain adequate levels of unassigned fund balance to mitigate financial risk that can occur from unforeseen revenue fluctuations, unanticipated expenditures, and similar circumstances. The intent of this policy is to ensure the City maintains adequate fund balances in the City's various operating funds with respect to the following:

1. Providing sufficient cash flow liquidity for the City's general governmental operations,
2. Securing and maintaining investment grade bond ratings,
3. Offsetting significant economic downturns or revenue shortfalls, and
4. Providing funds for unforeseen expenditures related to emergencies.

DEFINITIONS

Fund Equity – A fund's equity is generally the difference between its assets and liabilities.

Fund Balance – An accounting distinction is made between the portions of fund equity that are spendable and non-spendable. These included the following categories:

1. Non-spendable fund balance – includes amounts that are not in a spendable form or are required to be maintained intact. Examples include inventory and prepaid expenses.
2. Spendable Fund Balance:
 - A. Restricted – includes amounts that are constrained for specific purposes that are externally imposed by providers, such as creditors, grantors, or contributors, or amounts constrained due to regulations of other governments. Examples include grant awards and bond proceeds.
 - B. Committed – Includes amounts that are limited to specific purposes that are *internally imposed* by the City through formal action of the City Council. Commitments may be changed or removed only by formal action of the City Council. This includes balances formally approved by the City Council during the budget adoption and amendment process. The formal action must be

approved by the City Council prior to the end of the fiscal year in which the commitment will be reflected on the financial statements.

- C. Assigned – includes amounts that are intended for specific purposes that are considered neither restricted nor committed. Intent can be expressed by the City Council or by an official to which the City Council delegates the authority. Assignments of fund balance are less formal than commitments and do not require formal action for their imposition or removal. In governmental funds other than the General Fund, the assigned fund balance represents the amount that is not restricted or committed. This indicates that resources in other governmental funds are, at a minimum, intended to be used for the purpose of that fund.
- D. Unassigned – the residual classification of amounts in the General Fund, which includes all amounts not classified in other fund balance categories. Unassigned amounts are technically available for any purpose. Negative residual amounts for all other governmental funds are reported in this classification.

POLICY/PRACTICES

1. Minimum fund balance or fund balance reserve for City funds shall be as listed below. The reserve will be considered assigned fund balance, and other assignments and restrictions cannot be included as part of the reserve calculation:
 - a. General Fund – 35% of on-going expenditures
 - b. All other funds – 25% of on-going expenditures
2. The General Fund shall have a maximum fund balance of 60%, excluding non-reserve assignments and commitments. When the amount is exceeded, the City shall identify one-time expenditures for which to use the funds, consider tax rate changes, and/or review non-tax revenue rates to ensure no unnecessary over-collection of revenues.
3. For enterprise funds, the fund balance will be defined as working capital and shall represent current assets minus current liabilities without future bond payments.
4. The City Council may appropriate unassigned fund balance for emergency purposes, as deemed necessary, even if such use decreases the fund balance below the established minimum.
5. When multiple categories of fund balance are available for expenditure, such as a capital project being funded by a combination of grant funds, funds set aside by the City Council, and unassigned fund balance, the City will spend project funds from the most restricted category first (e.g., grant funds). When the most restricted fund balance has been spent on the project, then funds will be spent from the next most restrictive category (e.g., committed or assigned fund balance), continuing this pattern until all project funds have been expended.
6. The city shall minimize the use of committed fund balances in major operating funds when possible. Methods of reducing the commitments include transferring project funds to capital projects, creating and maintaining equipment replacement and long-term maintenance funds, and creating and maintaining operating project funds for non-capital projects.

- 7. The Finance Administrator shall be responsible for monitoring and reporting the City's various reserve balances. The City Administrator is directed to make recommendations to the Council regarding the use of reserve funds as an element of the annual operating budget submission or as necessary throughout the fiscal year, as circumstances may arise.
- 8. Compliance with the provisions of this policy shall be reviewed as a part of the annual operating budget adoption and subsequent review will be included in the annual audit and financial statement preparation procedures.

[Approved September 05, 2024, by the La Vernia City Council, Resolution # _____]



July 16, 2024

Via Federal Express

To the Honorable Mayors and Council Members:

Attached is a copy of the Statement of Intent of West Texas Gas Utility, LLC (“WTGU” or the “Company”), to increase gas utility rates within the incorporated areas of the Cities of Amarillo, Balmorhea, Cactus, Canadian, Canyon, Claude, Dalhart, Darrouzett, Devine, Eden, Farwell, Follett, Groom, Higgins, Junction, Kermit, La Vernia, Lockhart, Lubbock, Luling, Menard, Miami, Mobeetie, Natalia, Paint Rock, Seguin, Shamrock, Somerset, Sonora, Stratford, Texhoma, Texline, Van Horn, Wheeler, White Deer and Wolfforth, Texas (“Cities”). WTGU is filing a Statement of Intent at this time to more accurately match base rates with the costs of providing service and to recover extraordinary gas costs related to Winter Storm Uri through a separate surcharge. The Company requests that the proposed rates and tariffs contained in the Statement of Intent become effective on August 20, 2024, which is 35 days from the date of this filing. No action on the part of the Cities is required to permit the Company’s proposed rates to take effect.

In addition to this city-level filing, the Company is also making a Statement of Intent filing with the Railroad Commission of Texas for the unincorporated areas of the seventy-three Counties in Texas that WTGU serves. The Company is requesting that the Cities and the Commission approve the same rates and tariffs and is providing the same information, including written testimony, to the Cities it serves and to the Commission.

If you have any questions, please do not hesitate to contact me.

Best regards,

A handwritten signature in blue ink, appearing to read "J.J. King", is written over a light blue circular stamp.

J.J. King
Vice President of Gas Marketing

JJK:eas
Attachment

cc: Amanda Edgmon, Treasurer/Secretary, West Texas Gas Utility, LLC
Kate Norman, Coffin Renner LLP

**STATEMENT OF INTENT OF WEST TEXAS GAS UTILITY, LLC
TO INCREASE GAS UTILITY RATES WITHIN THE
UNINCORPORATED AREAS OF TEXAS**

To All Cities Within the State of Texas Served by West Texas Gas Utility, LLC:

West Texas Gas Utility, LLC (“WTGU” or “the Company”), a “gas utility” under Gas Utility Regulatory Act (“GURA”)¹ § 101.003(7), respectfully files this Statement of Intent, pursuant to Subchapter C of Chapter 104 of GURA and the rules of the Gas Services Department of the Railroad Commission of Texas (“Commission”), to increase gas utility rates within the unincorporated areas within Andrews, Archer, Armstrong, Atascosa, Bailey, Bastrop, Bexar, Brewster, Briscoe, Brown, Caldwell, Carson, Castro, Cochran, Coleman, Collingsworth, Concho, Crosby, Culberson, Dallam, Dawson, Deaf Smith, Dimmit, Donley, Floyd, Frio, Gaines, Gray, Hale, Hall, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Jeff Davis, Kimble, Kinney, La Salle, Lamb, Lipscomb, Lubbock, Lynn, McCulloch, Martin, Mason, Maverick, Medina, Menard, Moore, Ochiltree, Oldham, Parmer, Pecos, Potter, Presidio, Randall, Reeves, Roberts, Runnels, Sherman, Sutton, Swisher, Terry, Tom Green, Travis, Uvalde, Val Verde, Wheeler, Wilson, Winkler, Yoakum, and Zavala Counties.² WTGU’s natural gas service area also includes the Cities of Amarillo, Balmorhea, Cactus, Canadian, Canyon, Claude, Dalhart, Darrouzett, Devine, Eden, Farwell, Follett, Groom, Higgins, Junction, Kermit, La Vernia, Lockhart, Lubbock, Luling, Menard, Miami, Mobeetie, Natalia, Paint Rock, Seguin, Shamrock, Somerset, Sonora, Stratford, Texhoma, Texline, Van Horn, Wheeler, White Deer, and Wolfforth, Texas. The Company’s proposed rates were developed based on WTGU’s costs to serve customers in the entirety of its Texas service area that take service under rate schedule tariffs approved by either a municipality or the Commission (“Jurisdictional Customers”). Contemporaneously with this filing, WTGU is also filing a Statement of Intent to Increase Rates for Jurisdictional Customers within each of the municipalities served by WTGU.

The Company requests that the proposed tariffs, attached as **Exhibit A** to this Statement of Intent and incorporated herein by reference, become effective on August 20, 2024, which is 35

¹ Tex. Util. Code §§ 101.001 *et seq.*

² This pleading uses the terms “unincorporated areas” and “environs” interchangeably.

days from the date of this filing. In support of its request, the Company respectfully shows as follows:

I. INTRODUCTION AND SUMMARY OF THE RATE REQUEST

WTGU is proposing new rates for the jurisdictional service it provides in Texas based on the cost of providing service to all Jurisdictional Customers within its service area, inclusive of both incorporated and unincorporated areas served by WTGU.³ This approach is consistent with the system-wide rates that are currently in effect for WTGU. For the 12-month period ended December 31, 2023, the Company’s overall jurisdictional base rate revenue requirement on a system-wide basis totaled approximately \$26,466,131. The total adjusted revenue WTGU currently receives from jurisdictional customers is approximately \$13,188,368, leaving a revenue deficiency of approximately \$13,277,763. However, to moderate the effect of WTGU’s rate change request on its customers, WTGU is not requesting to recover its full jurisdictional cost of service through this Statement of Intent. Rather, WTGU is requesting a base rate revenue requirement on a jurisdictional, system-wide basis of approximately \$19,967,258.

If approved, the requested rates will increase WTGU’s jurisdictional revenues in Texas by \$6,778,890 which is an increase of approximately 35.75% total revenues including gas costs, or 51.40% base rate revenues, which excludes gas costs. Because the proposed changes will increase WTGU’s total aggregate revenues by more than 2.5%, the proposed rate change constitutes a “major change” in rates as that term is defined by GURA § 104.101. Additionally, regarding GURA § 104.006, the proposed rates for areas not within a municipality will not exceed 115% of the average of all rates for similar services of all municipalities served by the Company within the same county.

As part of this rate filing, the Company is also requesting: (1) a prudence determination for all used and useful capital investment WTGU has made through December 31, 2023, including all capital investment reflected in the Company’s interim rate adjustment (“IRA”) filings made since WTGU’s last statement of intent proceeding, pursuant to GURA § 104.301; (2) approval of a

³ WTGU serves domestic and non-domestic jurisdictional customers and irrigation and agricultural non-jurisdictional customers. Domestic customers are residential customers. Non-domestic customers are all other jurisdictional customers.

51.22% allocation factor for capital investment costs that should be allocated to or recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers to be used in future IRA filings; (3) Commission approval of new depreciation rates; (4) Commission approval of a regulatory asset comprised of extraordinary gas costs related to WTGU’s continuation of service during Winter Storm Uri; (5) recovery of the Winter Storm Uri regulatory asset through a monthly surcharge over 60 months; (6) approval of its tariffs contained in Exhibit A; and (7) approval of a rate case expense recovery surcharge to recover the reasonable rate case expenses associated with this filing through a surcharge on rates, as provided by law. The exact amount of rate case expense will not be known until the case is complete.

The tariffs, attached hereto as **Exhibit A** to the Rate Filing Package and made a part hereof, support the rate changes proposed by the Company. The Company is proposing revised tariffs for natural gas service that will include rates for domestic and non-domestic customers that will consist of a customer charge and a volumetric charge. Implementation of new tariffs necessarily entails withdrawal of the Company’s existing incorporated and environs tariffs. Other tariff changes are detailed in Section III(F) below.

II. JURISDICTION

WTGU is a gas utility as that term is defined in GURA § 101.003(7). Pursuant to GURA § 102.001(a), the Commission has exclusive original jurisdiction to set the rates WTGU requests for Jurisdictional Customers in the unincorporated areas served by WTGU. Consistent with such jurisdiction, the proposed rates identified in Exhibit A are applicable to the Company’s natural gas service within the unincorporated areas. The Commission also has appellate authority over municipalities exercising original jurisdiction over the Company’s filings.

III. DETAILS OF PROPOSED CHANGES

A. Rate Filing Package

In addition to this Statement of Intent, the Rate Filing Package consists of the following:

- Exhibit A Proposed Tariffs
- Exhibit B Proposed Revenue Change by Class
- Exhibit C Average Bill Impact by Class

- Exhibit D Direct Testimony and Exhibits
- Exhibit E Proposed Notice
- Exhibit F Protective Agreement
- Exhibit G Cost of Service Schedules
- Exhibit H Workpapers

B. Test Year

The Company’s proposed cost of service as set forth in this Statement of Intent and Rate Filing Package is based on the 12-month period ended December 31, 2023.

C. Class and Number of Customers Affected

The proposed changes to the Company’s tariffs will affect all Jurisdictional Customers that WTGU serves in Texas. The table below shows the approximate number of customers by class, who will be affected by the proposed rate changes:

**Table 1
Customer Classes Affected**

Customer Class	Environs Customers	Incorporated Customers
Domestic ⁴	5,747	12,176
Non-Domestic ⁵	475	2,010

Exhibits B and C, attached, show the amount of the proposed change and the effect of the proposed change on an average bill for each class of customers.

D. Proposed Rate Change

The proposed changes to rates for jurisdictional customers are set out below:

⁴ A “domestic customer” typically refers to residential service and is one whose natural gas service is individually metered.

⁵ A “non-domestic customer” is a customer who is not taking service under the residential tariff and includes commercial, industrial customers, public authority customers, and non-profit customers.

Table 2
Comparison of Current Rates to Proposed Rate Change⁶

Domestic Customers		
	Current	Proposed
Customer Charge	\$23.42 per month	\$29.50 per month
All Consumption ⁷	\$4.84 per Mcf	\$7.68 per Mcf
Non-Domestic Customers		
	Current	Proposed
Customer Charge	\$43.57 per month	\$79.00 per month
All Consumption	\$2.69 per Mcf	\$4.89 per Mcf

Exhibit C shows the average bill impact by customer class.

E. Depreciation Rates

The Company requests that the Commission approve new depreciation rates for WTGU and all of its natural gas assets.

F. Other Proposed Tariff Changes

In addition to the proposed changes in rates, WTGU proposes to add a new Winter Storm Cost Recovery Rider to recover approximately \$3.5 million over a five-year period. The Company also proposes to remove the EDIT Credit Rider because the credit associated with that rider is complete and to make non-substantive changes to the Pipeline Safety Fee Rider. The Company also proposes non-substantive formatting changes to its tariffs. WTGU does not propose to change the fee, deposit, or general terms of service provisions in the tariffs.

G. Effective Date

The Company requests that the Commission order the proposed rates to be effective for bills rendered on and after August 20, 2024, which is 35 days after the filing date.

⁶ The current rate amounts include amounts for the Company’s pending GRIP filing in Case No. 00017395.

⁷ The terms “All Consumption” and “Volumetric” are used interchangeably.

H. Witness Testimony

Attached as **Exhibit D** to the Statement of Intent is the direct testimony supporting the Company's requested revenue requirement. The attached testimony includes the following witnesses:

- *Jack J. ("J.J.") King*, Vice President of Gas Marketing, provides an overview of the Company's operations, service territory, customer base and rate filing; supports the prudence of the Company's capital investment; explains affiliate relationships and transactions; addresses certain expense items; addresses extraordinary costs incurred during the Company's response to Winter Storm Uri; and identifies the tariff changes WTGU is requesting.
- *Amanda Edgmon*, Treasurer/Secretary also serving as WTGU Regulatory Accountant, addresses the Company's books and records; attests to the financial information contained in the Company's schedules; sponsors the Company's Gas Reliability Infrastructure Program ("GRIP") filings; discusses the proposed change to the factor to be used in future GRIP filings to determine the amount of capital investment that should be allocated to or recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers; presents the calculation of the regulatory asset amounts related to Winter Storm Uri; and explains the corporate cost allocation method and services from some affiliates.
- *Matthew S. Smith, P.E.*, Associate Vice President of Operations, provides an overview of field operations and expenses and supports the Company's rationale for its request to modify the factor used to determine what portion of the Company's capital investment will be recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers.
- *Dane A. Watson*, with Alliance Consulting Group, sponsors the depreciation study that he performed that produces the depreciation rates used to determine the Company's depreciation expense.
- *Dr. Bruce H. Fairchild*, Principal with Financial Concepts and Applications, Inc., sponsors the Company's cost of service schedules, requested capital structure and return on equity, overall rate of return, billing determinants, income tax expense and other tax issues, cost allocation and rate design; and presents the Company's proposed method for direct assignment of costs attributable to Jurisdictional Customers and Non-Jurisdictional Customers.

IV. RATE CASE EXPENSES

Pursuant to GURA § 104.051 and Commission Rule § 7.5530, WTGU requests recovery of all reasonable and necessary rate case expenses from affected customers through a surcharge to the final approved rates.

V. PUBLIC NOTICE

The Company will promptly undertake to notify the public of the proposed changes in its gas rates consistent with the requirements of GURA § 104.103 and Commission Rules §§ 7.230 and 7.235. The public notice that WTGU proposes to provide regarding the proposed change in rates is attached as **Exhibit E** to the Statement of Intent. WTGU asks that the Commission’s Administrative Law Judge and Examiners approve its form of notice prior to publication or distribution to customers, and the Company will submit proof of notice promptly upon completion thereof.

VI. COMPANY REPRESENTATIVES FOR NOTIFICATION

WTGU’s authorized representatives are:

J.J. King, Vice President- Gas Marketing
Amanda Edgmon, Treasurer/Secretary
West Texas Gas Utility, LLC
303 Veterans Airpark Ln, Suite 500
Midland, Texas 79705
(432) 682-4349
jking@westtexasgas.com
aedgmon@westtexasgas.com

and

Kate Norman
C. Glenn Adkins
Tandy Sticklen
Elizabeth Seyl
Coffin Renner LLP
1011 W. 31st Street
Austin, Texas 78705
512-879-0900
512-879-0912 (fax)
kate.norman@crtxlaw.com
glenn.adkins@crtxlaw.com
tandy.sticklen@crtxlaw.com
elizabeth.seyl@crtxlaw.com

Please serve all pleadings, motions, orders, and other documents filed in this proceeding upon WTGU’s authorized representatives at the above-stated addresses.

VII. PROTECTIVE AGREEMENT

The Company's Rate Filing Package includes certain confidential materials. In addition, the scope of discovery in this case may require the production of additional confidential material. Accordingly, WTGU attaches as **Exhibit F** to this Statement of Intent a Protective Agreement to be used in this case. WTGU will provide confidential material upon execution of Exhibit A attached to the Protective Agreement.

VIII. CONCLUSION

WTGU requests that: (1) rates are approved consistent with those proposed herein to become effective for bills rendered on and after August 20, 2024; (2) capital investment WTGU has made through December 31, 2023 is deemed prudent; (3) the Commission approve the use of a 51.22% allocation factor for capital investment costs that should be allocated to or recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers to be used in future IRA filings; (4) the Commission approve new depreciation rates; (5) the proposed tariffs be approved; (6) the Commission approve the requested regulatory asset amount for costs related to Winter Storm Uri; (7) the Commission approve recovery of the Winter Storm Uri regulatory asset amount through a monthly surcharge over 60 months; (8) all reasonable rate case expenses incurred in connection with this Statement of Intent filing are authorized for recovery by the Company; and (9) for such further relief to which the Company may be entitled.

Respectfully submitted,

By: Kate Norman

Kate Norman
State Bar No. 24051121
C. Glenn Adkins
State Bar No. 24037433
Coffin Renner LLP
1011 West 31st Street
Austin, Texas 78705
512/879-0900
512/879-0912 (fax)
kate.norman@crtxlaw.com
glenn.adkins@crtxlaw.com

**ATTORNEYS FOR WEST TEXAS GAS
UTILITY, LLC**

WEST TEXAS GAS UTILITY, LLC

Page 1 of 1

Effective: _____

COMMERCIAL SERVICE RATE - ENVIRONS**APPLICABILITY**

Applicable to all commercial customers and to customers not otherwise specifically provided for under any other rate schedule or served under a contract in an unincorporated or environs area served by West Texas Gas Utility, LLC (“WTGU”). This rate is only available to full requirements customers of WTGU.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Commercial consumers and to consumers not otherwise specifically provided for under any other rate schedule or served under a contract per meter billing cycle or for any part of a billing cycle for which gas service is available at the same location.

Customer Charge	\$79.00
All Consumption @	\$4.89 per Mcf

The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

OTHER FEES

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule Gas Cost Adjustment-ENV.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-ENV.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEES-ENV.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-ENV.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

WEST TEXAS GAS UTILITY, LLC

Page 1 of 6

Effective: _____

RATE SCHE

Section 7, Item A.

GAS COST ADJUSTMENT-ENV

GAS COST ADJUSTMENT – ENVIRONS**Applicability**

This clause shall apply to all customers served by WTGU, except for customers purchasing gas at contract rates. Each customer's gas costs will be determined by the costs incurred in the applicable Gas Cost Zone. For purposes of determining gas purchase costs, all customers will be located in one of three Gas Cost Zones: North, South, and West. Each Gas Cost Zone consists of the following systems or geographic areas:

NORTH GAS COST ZONE:

Unincorporated areas of the Counties of Armstrong, Carson, Collingsworth, Dallam, Deaf Smith, Donley, Gray, Hall, Hansford, Hartley, Hemphill, Hutchinson, Lipscomb, Moore, Ochiltree, Oldham, Potter, Randall, Roberts, Sherman and Wheeler.

SOUTH GAS COST ZONE:

Unincorporated areas of the Counties of Atascosa, Bastrop, Bexar, Brown, Caldwell, Coleman, Concho, Dimmitt, Frio, Kimble, Kinney, La Salle, Mason, Maverick, McCulloch, Medina, Menard, Runnels, Sutton, Tom Green, Travis, Uvalde, Val Verde, Wilson, and Zavala.

WEST GAS COST ZONE:

Unincorporated areas of the Counties of Andrews, Archer, Bailey, Brewster, Briscoe, Castro, Cochran, Crosby, Culberson, Dawson, Floyd, Gaines, Hale, Hockley, Jeff Davis, Lamb, Lubbock, Lynn, Martin, Parmer, Pecos, Presidio, Reeves, Swisher, Terry, Winkler and Yoakum.

Intent

This clause is intended to allow collection of West Texas Gas Utility, LLC's ("WTGU") gas purchase costs in a manner that will lessen monthly fluctuations in the gas cost factor and ensure that all amounts billed to customers are fully reconciled with actual costs incurred, subject to limitations for excessive lost and unaccounted for gas.

Definitions

Gas Cost Zones – North, South, and West, as defined in the "Applicability" section below.

Interest – The percentage of interest shall be the interest rate established by the Public Utility Commission, or such other agency or manner as determined by the Commission, under Chapter 183 of the Texas Utilities Code.

Lost and Unaccounted For Gas – Lost and Unaccounted for Gas (LUG) shall represent volumes of gas metered into the distribution system and volumes of gas metered out of the distribution system at 14.65 p.s.i.a., which shall include distribution and non-distribution volumes. WTGU transmission LUG shall not be included in these volumes.

WEST TEXAS GAS UTILITY, LLC

Page 2 of 6

Effective: _____

RATE SCHE
GAS COST ADJUSTMENT-ENV

Purchased Gas Costs –The total cost of Purchase Volumes, as received into the Company’s distribution systems within each Gas Cost Zone.

Purchased Gas Factor (“PGF”) – A factor on each customer’s monthly bill, expressed in dollars per Mcf, to reflect the Purchase Gas Costs, all as more specifically described herein.

Purchase/Sales Ratio – A ratio determined by dividing the Company’s Purchase Volumes metered into the distribution system during the twelve-month period ending June 30 of each year by the sum of the Company’s Sales Volumes metered out of the distribution system, volumes of metered Company used gas, and losses of gas from the Company’s systems within each Gas Cost Zone that have been billed to third parties during the same period. Such ratio as determined shall in no event exceed 1.0526 i.e. $1/(1-.05)$ unless expressly authorized by the applicable regulatory authority.

Purchase Volumes – The volumes of gas, expressed in Mcf’s and stated at 14.65 psia, received by the Company’s distribution system from all sources within each Gas Cost Zone, including monthly purchases and withdrawals from storage, if any, for use by general service customers. This quantity of gas shall not include LUG attributable to the WTGU Transmission System or transmission function.

Reconciliation Amount – The net of any monthly imbalances by Gas Cost Zone during the period covered by the Reconciliation Review.

Reconciliation Component – The monthly amount to be refunded or passed through to customers within each Gas Cost Zone, consisting of one-twelfth of the Reconciliation Amount.

Reconciliation Factor – A factor, expressed as a cost per Mcf on customer bills within each Gas Cost Zone, reflecting the customer’s share of the Reconciliation Component applicable to the period covered by the bill.

Reconciliation Review – An annual review of the Company’s records covering each 12-month period ending June 30 to determine any imbalances between the Purchase Gas Cost and the Sales Amount as applied to each Gas Cost Zone during that period.

Sales Amount – Sales Volumes, volumes of metered Company used gas, and losses of gas from the Company’s system within each Gas Cost Zone that have been billed to third parties, multiplied by the Purchased Gas Factor.

Sales Volumes – The volumes of gas metered to general service customers within each Gas Cost Zone expressed in Mcf’s and stated at 14.65 psia.

Weighted Average Cost of Gas – The Purchase Gas Costs invoiced by third parties divided by the Purchase Volumes, calculated on a monthly basis for each Gas Cost Zone.

WEST TEXAS GAS UTILITY, LLC

Page 3 of 6

Effective: _____

**RATE SCHE
GAS COST ADJUSTMENT-ENV**

Purchase Gas Cost Component (PGC)

The Purchase Gas Cost for each Gas Cost Zone shall be computed utilizing the following components for the distribution system customers:

- Cost of gas purchased
- Credits, Refunds or Out of Period adjustments
- Cost of gas withdrawn from storage
- Interest on storage gas withdrawn
- Upstream Gathering and Transportation Charges
- Storage Deliverability Charges
- Storage Capacity Charges
- New taxes on the purchased gas or the purchase transaction and not reflected on elsewhere on customer bills

WTGU shall keep accurate records of all storage gas purchases, including the date, quantity, cost, and associated expenses. WTGU shall account for storage gas purchases and withdrawals using a weighted average cost basis.

Purchased Gas Factor (PGF) Calculation

Each customer bill shall include a Purchased Gas Factor reflecting the estimated Weighted Average Cost of Gas, plus additional elements described in this section, during the period covered by the bill for each Gas Cost Zone. The PGF shall be determined to the nearest \$0.001 per Mcf, and the following provisions shall apply:

- In addition to the estimated weighted average cost of gas for the current month’s billing period, the PGF may include a pro rata portion of an amount reflecting the difference between the estimated Weighted Average Cost of Gas and the actual Weighted Average Cost of Gas during the previous billing period for each Gas Cost Zone
- The PGF shall also include a “Reconciliation Factor,” an amount reflecting the customer’s share of any gas cost imbalances in the preceding reconciliation period for each Gas Cost Zone.
- The PGF factor may also include an amount reflecting any new taxes or levies specifically applied to gas costs or purchases and not otherwise reflected on the customer bill for each Gas Cost Zone.

The Purchased Gas Factor is expressed as a formula as follows:

$$(A+/-B) + C + D = E$$

Where:

- | | |
|--------------------------------------|---------------------------|
| A = Estimated WACOG | C = Reconciliation Factor |
| B = Est. WACOG/Act. WACOG Difference | D = New Taxes |
| | E = Total PGF |

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Gas Cost Reconciliation (GCR)

WTGU shall keep accurate books and records of the Reconciliation Review, monthly Purchased Gas Factor reports to the Railroad Commission of Texas, and shall account for the Reconciliation Component and the Reconciliation Factors for each Gas Cost Zone.

A Reconciliation Review and calculation shall first determine whether the lost and unaccounted for gas is more or less than 5% of that metered into the system. The sales volumes shall be converted to the same pressure base as the purchase volumes. Calculations of the sales volumes furnished to its gas sales customers (from meters not corrected for pressure and/or temperature) shall be calculated utilizing the following service pressures (psia):

Unincorporated areas of the Counties of:

Andrews	13.45	Frio	14.68	Ochiltree	13.78
Archer	13.45	Gaines	13.45	Oldham	13.45
Armstrong	13.38	Gray	13.78	Parmer	13.18
Atascosa	14.68	Hale	13.45	Pecos	13.68
Bailey	13.45	Hall	13.45	Potter	13.45
Bastrop	14.68	Hansford	13.78	Presidio	13.48
Bexar	14.68	Hartley	13.07	Randall	13.45
Brewster	13.48	Hemphill	13.88	Reeves	13.48
Briscoe	13.45	Hockley	13.45	Roberts	13.68
Brown	14.08	Hutchinson	13.68	Runnels	14.28
Caldwell	14.68	Jeff Davis	13.48	Sherman	13.18
Carson	13.38	Kimble	14.18	Sutton	13.98
Castro	13.45	Kinney	14.68	Swisher	13.45
Cochran	13.45	LaSalle	14.68	Terry	13.45
Coleman	14.08	Lamb	13.45	Tom Green	14.28
Collingsworth	13.38	Lipscomb	13.78	Travis	14.68
Concho	14.08	Lubbock	13.45	Uvalde	14.68
Crosby	13.45	Lynn	13.45	Val Verde	14.68
Culberson	13.48	Martin	13.45	Wheeler	13.78
Dallam	13.07	Mason	14.08	Wilson	14.68
Dawson	13.45	Maverick	14.68	Winkler	13.68
Deaf Smith	13.45	McCulloch	14.08	Yoakum	13.45
Dimmitt	14.68	Medina	14.68	Zavala	14.68
Donley	13.38	Menard	14.08		
Floyd	13.45	Moore	13.28		

If the Reconciliation Review indicates a gas loss or gas gain of less than 5% of that metered into the system, the following methodology shall apply:

- WTGU shall calculate the imbalance between its Net Jurisdictional Cost of Gas and amount collected through the PGA billed on a monthly basis for said Gas Cost Zone. The Net Jurisdictional Cost of Gas shall be calculated by multiplying the Total Jurisdictional Sales

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RATE SCHE**GAS COST ADJUSTMENT-ENV**

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Volumes by the Actual P/S Ratio to arrive at the Calculated Purchased Volume. The Calculated Purchased Volume is then multiplied by the WACOG to arrive at the Net Jurisdictional Cost of Gas.

- Interest shall be applied to each monthly imbalance for said Gas Cost Zone and shall accrue for each month of the review period.
- The interest rate shall be the same rate as determined by the Public Utility Commission of Texas for refunds on customer deposits and in effect during the last month of the audit period (June).
- The sum of the monthly imbalances, plus interest, for each Gas Cost Zone for the period under review shall be the Reconciliation Amount, the total amount to be refunded/surcharged in said Gas Cost Zone.

If the Reconciliation Review indicates a gas loss or gas gain of greater than 5% of that metered into the system, the following methodology shall apply:

- WTGU shall calculate the imbalance between its Purchase Gas Cost and Sales Amount on a monthly basis for said Gas Cost Zones Purchase Gas Cost amounts in excess of the 1.0526 ratio shall be disallowed by:
 - 1) Dividing total Purchase Volumes for the 12-month review period by the total Sales Volumes for the same period in said Gas Cost Zone.
 - 2) Subtracting that result from 1, which when expressed as a percentage, becomes said Gas Cost Zones "Actual P/S Ratio."
 - 3) Subtracting 5.26% from said Gas Cost Zones Actual P/S Ratio, results in a "Disallowance Factor" for the review period.
 - 4) Multiplying the Disallowance Factor by the Purchase Volumes for each month and by the Weighted Average Cost of Gas for each month, for said Gas Cost Zone will result in an amount to be disallowed each month.
 - 5) The Net Jurisdictional Cost of Gas shall be calculated by multiplying the Total Jurisdictional Sales Volume by the Actual P/S Ratio to arrive at the Calculated Purchased Volume. The Calculated Purchased Volume is then multiplied by the WACOG to arrive at the Jurisdictional Cost of Gas. The Net Jurisdictional Cost of Gas is calculated by subtracting the Disallowed Amount calculated above.
- Interest shall be applied to each monthly imbalance for said Gas Cost Zone and shall accrue for each month of the review period.
- The interest rate shall be the rate in effect during the last month of the audit period (June).

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- The sum of the monthly imbalances, plus interest, for the period under review shall be the Reconciliation Amount for said Gas Cost Zone or the total amount to be refunded/surcharged.

Reconciliation Factor Calculation (RFC)

The Reconciliation Amount for each Gas Cost Zone shall be divided by 12, resulting in the Reconciliation Component.

The Reconciliation Component shall be reflected in a refund or surcharge on each customer bill, according to Gas Cost Zone, over a twelve-month period beginning with the first billing cycle in September following the period covered by the review.

The Reconciliation Component for each month of the reconciliation period shall be calculated by dividing the Reconciliation Amount by the estimated Sales Volumes for the applicable billing period. The result will be a monthly Reconciliation Factor, expressed in Mcf for each Gas Cost Zone. Any under or over collection from the prior month may be factored in subsequent months' Reconciliation Component.

Each month during the reconciliation period, the PGF for each Gas Cost Zone on customer bills shall be increased or reduced by the product of the number of Mcf billed to the customer and the monthly Reconciliation Factor, as indicated in the section of PGF calculations. Any under or over collections remaining at the end of the gas reconciliation period will be carried forward to the next gas reconciliation period.

MISCELLANEOUS FEES AND DEPOSITS – ENVIRONS

APPLICABILITY

Applicable to Residential, Commercial, Industrial, and any other jurisdictional customers of West Texas Gas Utility, LLC (“WTGU”) who are in an unincorporated or environs area served by WTGU.

FEES

Initiation of Service:

a) Connection Charge

The following connection charges apply:

<u>Schedule</u>	<u>Charge</u>
Business Hours (8AM to 5PM, Monday – Friday, except holidays)	\$50.00
After Hours (All Hours not associated with Business Hours)	\$70.00

A connect fee will be charged to any applicant for the cost involved in initiation of service. This fee shall be charged when a meter is set and/or gas turned on.

b) Read-In for Change Charge

A read-in fee of \$20.00 will be charged to any applicant for the cost involved in initiation of service. This fee shall be charged when only a meter reading is required.

c) After Hours & Special Handling

In addition to initiation of service fee above, a fee shall be charged to any applicant whose request to initiate service cannot be completed during normal business hours or requires special handling. Applicant shall be advised that an additional fee will be charged and must agree to pay such charge. Any fees assessed will reflect actual time incurred at \$20 per hour during business hours and \$30 per hour for after hours, plus the actual cost of materials and any incidental (third party) expenses. A third party is any person or entity, including an affiliate of the Company.

- (i) **Special Handling:** West Texas Gas Utility, LLC (“WTGU”) may, at customer’s request, provide special handling in order to meet the Customer’s requirements for a fee based on the rates indicated in (c) above. Special handling may include such assistance as calling the customer in advance or making other special arrangements (such as A.M. or P.M. scheduling) for access to the customer’s premises.

- (ii) **Expedited Service:** If the customer requires that the order be worked after hours for their convenience or if the customer requires expedited service, the charge shall be based on the rates indicated in (c) above for after-hours service work on customer premises. The Customer's request for expedited service may then be scheduled at any time to fit WTGU's work schedule but the after-hours charge shall be collected as long as any other work is done on overtime.
- (iii) **Special Call Out:** If the initiation of service order requires special call out, the customer shall be charged based on the rates indicated in (c) above for after-hours service work on customer's premises.

Customer Requested Meter Test

Whenever WTGU is requested by a customer to have a meter test performed, and the result of that meter test indicates that the meter is within 2% accuracy and the meter has been tested within a four year period from the time the customer made the request the customer will be charged according to the following fee schedule.

Positive Displacement	Charge
275 cubic feet per hour or less	\$25.00
276 to 1500 cubic feet per hour	\$30.00
1501 to 3000 cubic feet per hour	\$35.00
3001 to 5000 cubic feet per hour	\$45.00
over 5000 cubic feet per hour	\$60.00
Orifice Meters	
All sizes	\$40.00

The meter test fees schedule above will not apply when the test results indicate the meter is outside of the allowed 2% accuracy range.

Returned Check/Bank Draft Charges

Accounts for which payment is made using checks or electronic drafts which are returned or denied by a bank for any reason may be charged a fee for each occurrence of \$25.00.

Collection Fee

A fee of \$20.00 will be charged to any customer whose failure to respond to a termination notice necessitates the dispatch of a Company representative who attempts collection of payment from customer.

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Reconnect Fees

The following reconnection fees will be charged to any customer whose service is terminated and then re-initiated unless terminated in error by WTGU.

<u>Schedule</u>	<u>Charge</u>
Business Hours (8AM to 5PM, Monday – Friday, except holidays)	\$50.00
After Hours (All Hours not associated with Business Hours)	\$70.00

Temporary Service

Customers will be charged the actual cost of installation and removal of pipe and metering facilities. The actual cost will be calculated in accordance with the rates specified in Section 4.1.1 (c) above. This service does not include extension of mains.

Special Read

Customer requested reading of a meter for any purpose other than initiation of service will be charged \$20.00

No Access

A fee of \$20.00 will be charged to customer who schedules an appointment but fails to appear or Company personnel cannot access property to perform the service requested.

Tampering

Customers who tamper with their meters will be assessed a charge of \$150.00 plus the actual cost of any estimated volumes of gas illegally consumed or improperly measured based on such tampering, and the actual cost of time and materials to repair meters or other company equipment. The actual costs will be based on the labor rates and costs specified in Section 4.1.1 (c) above. This charge is not intended to duplicate any charge that may be imposed by the Texas Penal Code.

Extension Fee

In the event the cost of extending mains in an incorporated area exceeds the free limit established by the Franchise Agreement for domestic and non-domestic customers in the area, customers shall pay the actual cost of the extension, based on costs calculated in accordance with the rates specified in Section 4.1.1 (c) above, less the free limit. In the event the Franchise Agreement does not establish a free limit, and in all unincorporated areas, the customers shall pay the actual cost of the extension, less a \$150.00 credit, based on costs calculated in accordance with the rates specified in Section 4.1.1 (c) above.

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DEPOSITS

Customer Deposits

Deposits will be based on 1/6 of the customers estimated annual usage. For any customer who pays bills by electronic transfer to WTGU, these deposits will be based on 1/12 of the customers estimated annual usage.

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**NON-PROFIT ENVIRONS
SERVICE RATE**

APPLICABILITY

Applicable to all non-profit customers.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Non-Profit consumers.

Customer Charge \$79.00
All Consumption @ \$4.89 per Mcf

The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

OTHER FEES

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule Gas Cost Adjustment-ENV.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-ENV.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEES-ENV.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-ENV.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

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OTHER SURCHARGES – ENVIRONS

West Texas Gas Utility, LLC will recover other surcharges from jurisdictional customers as authorized by federal, state and local regulatory authorities in accordance with applicable statutes, laws, regulations, orders, rules, contracts or agreements.

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PIPELINE SAFETY FEE

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PIPELINE SAFETY AND REGULATORY PROGRAM RATE SCHEDULE

Pipeline Safety and Regulatory Program Rate Schedule.

Applicability

Fee. Once annually, West Texas Gas Utility, LLC (“WTGU”) shall remit to the Commission the fee required in 16 TEX. ADMIN. CODE Section 8.201.

Surcharge. During the next billing cycle following WTGU remittance to the Commission of the fee, WTGU shall include on its customers’ bills a Pipeline Safety and Regulatory Program Surcharge, to the extent authorized in 16 TEX. ADMIN. CODE Section 8.201.

Formula. The Rule 8.201 surcharge is calculated in accordance with the following formula:

Rule 8.201(b) fee assessed by the Commission on WTGU
Divided by
Number of meters billed
Equals
Rule 8.201(b)(3) surcharge, applied per customer meter, once annually.

In this formula, the number of meters billed refers to the number of meters billed during the billing month that precedes the month the Rule 8.201(b)(3) surcharge is included on customer bills.

Compliance Report.

The Company shall file an annual pipeline safety fee (PSF) report no later than 90 days after the last billing cycle in which the pipeline safety and regulatory program fee surcharge is billed to customers. The Company shall file the report with the Railroad Commission of Texas addressed to the Director of Oversight and Safety Division, Gas Services Department, referencing Case No. OS-24-00017816, and titling the report “Pipeline Safety Fee Recovery Report”. The report shall include the following:

- a) the pipeline safety fee-amount paid to the Commission;
- b) the unit rate and total amount of the surcharge billed to each customer;
- c) the date or dates the surcharge was billed to customers; and
- d) the total amount collected from customers from the surcharge.

Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Compliance Filing
Director of Oversight and Safety Division
Gas Services Dept.
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

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PUBLIC AUTHORITY SERVICE RATE - ENVIRONS

APPLICABILITY

Applicable to all public authority customers.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Public Authority consumers.

Customer Charge	\$79.00
All Consumption @	\$4.89 per Mcf

The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

OTHER FEES

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule Gas Cost Adjustment-ENV.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-ENV.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEES-ENV.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-ENV.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

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**ENVIRONS
QUALITY OF SERVICE RULES
RATE SCHEDULE**

RULE §7.45 Quality of Service

For gas utility service to residential and small commercial customers, the following minimum service standards shall be applicable in unincorporated areas. In addition, each gas distribution utility is ordered to amend its service rules to include said minimum service standards within the utility service rules applicable to residential and small commercial customers within incorporated areas, but only to the extent that said minimum service standards do not conflict with standards lawfully established within a particular municipality for a gas distribution utility. Said gas distribution utility shall file service rules incorporating said minimum service standards with the Railroad Commission and with the municipalities in the manner prescribed by law.

(1) Continuity of service.

(A) Service interruptions.

(i) Every gas utility shall make all reasonable efforts to prevent interruptions of service. When interruptions occur, the utility shall reestablish service within the shortest possible time consistent with prudent operating principles so that the smallest number of customers are affected.

(ii) Each utility shall make reasonable provisions to meet emergencies resulting from failure of service, and each utility shall issue instructions to its employees covering procedures to be followed in the event of an emergency in order to prevent or mitigate interruption or impairment of service.

(iii) In the event of national emergency or local disaster resulting in disruption of normal service, the utility may, in the public interest, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

(B) Record of interruption. Except for momentary interruptions which do not cause a major disruption of service, each utility shall keep a complete record of all interruptions, both emergency and scheduled. This record shall show the cause of interruptions, date, time duration, location, approximate number of customers affected, and, in cases of emergency interruptions, the remedy and steps taken to prevent recurrence.

(C) Report to commission. The commission shall be notified in writing within 48 hours of interruptions in service affecting the entire system or any major division thereof lasting more than four hours. The notice shall also state the cause of such interruptions. If any service interruption is

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reported to the commission otherwise (for example, as a curtailment report or safety report), such other report is sufficient to comply with the terms of this paragraph.

(2) Customer relations.

(A) Information to customers. Each utility shall:

(i) maintain a current set of maps showing the physical locations of its facilities. All distribution facilities shall be labeled to indicate the size or any pertinent information which will accurately describe the utility's facilities. These maps, or such other maps as may be required by the regulatory authority, shall be kept by the utility in a central location and will be available for inspection by the regulatory authority during normal working hours. Each business office or service center shall have available up-to-date maps, plans, or records of its immediate area, with such other information as may be necessary to enable the utility to advise applicants and others entitled to the information as to the facilities available for serving that locality;

(ii) assist the customer or applicant in selecting the most economical rate schedule;

(iii) in compliance with applicable law or regulations, notify customers affected by a change in rates or schedule or classification;

(iv) post a notice in a conspicuous place in each business office of the utility where applications for service are received informing the public that copies of the rate schedules and rules relating to the service of the utility as filed with the commission are available for inspection;

(v) upon request inform its customers as to the method of reading meters;

(vi) provide to new customers, at the time service is initiated or as an insert in the first billing, a pamphlet or information packet containing the following information. This information shall be provided in English and Spanish as necessary to adequately inform the customers; provided, however, the regulatory authority upon application and a showing of good cause may exempt the utility from the requirement that the information be provided in Spanish:

(I) the customer's right to information concerning rates and services and the customer's right to inspect or obtain at reproduction cost a copy of the applicable tariffs and service rules;

(II) the customer's right to have his or her meter checked without charge under paragraph (7) of this section, if applicable;

(III) the time allowed to pay outstanding bills;

(IV) grounds for termination of service;

(V) the steps the utility must take before terminating service;

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(VI) how the customer can resolve billing disputes with the utility and how disputes and health emergencies may affect termination of service;

(VII) information on alternative payment plans offered by the utility;

(VIII) the steps necessary to have service reconnected after involuntary termination;

(IX) the appropriate regulatory authority with whom to register a complaint and how to contact such authority;

(X) the hours, addresses, and telephone numbers of utility offices where bills may be paid and information may be obtained; and

(XI) the customer's right to be instructed by the utility how to read his or her meter;

(vii) at least once each calendar year, notify customers that information is available upon request, at no charge to the customer, concerning the items listed in clause (vi)(I) - (XI) of this subparagraph. This notice may be accomplished by use of a billing insert or a printed statement upon the bill itself.

(B) Customer complaints. Upon complaint to the utility by residential or small commercial customers either at its office, by letter, or by telephone, the utility shall promptly make a suitable investigation and advise the complainant of the results thereof. It shall keep a record of all complaints which shall show the name and address of the complainant, the date and nature of the complaint, and the adjustment or disposition thereof for a period of one year subsequent to the final disposition of the complaint.

(C) Utility response. Upon receipt of a complaint, either by letter or by telephone, from the regulatory authority on behalf of a customer, the utility shall make a suitable investigation and advise the regulatory authority and complainant of the results thereof. An initial response must be made by the next working day. The utility must make a final and complete response within 15 days from the date of the complaint, unless additional time is granted within the 15-day period. The commission encourages all customer complaints to be made in writing to assist the regulatory authority in maintaining records of the quality of service of each utility; however, telephone communications will be acceptable.

(D) Deferred payment plan. The utility is encouraged to offer a deferred payment plan for delinquent residential accounts. If such a plan is offered, it shall conform to the following guidelines:

(i) Every deferred payment plan entered into due to the customer's inability to pay the outstanding bill in full must provide that service will not be discontinued if the customer pays

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current bills and a reasonable amount of the outstanding bill and agrees to pay the balance in reasonable installments until the bill is paid.

(ii) For purposes of determining reasonableness under these rules, the following shall be considered: size of delinquent account; customer's ability to pay; customer's payment history; time that the debt has been outstanding; reasons why debt has been outstanding; and other relevant factors concerning the circumstances of the customer.

(iii) A deferred payment plan, if reduced to writing, offered by a utility shall state, immediately preceding the space provided for the customer's signature and in bold-face print at least two sizes larger than any other used, that: "If you are not satisfied with this agreement, do not sign. If you are satisfied with this agreement, you give up your right to dispute the amount due under the agreement except for the utility's failure or refusal to comply with the terms of this agreement."

(iv) A deferred payment plan may include a one-time 5.0% penalty for late payment on the original amount of the outstanding bill with no prompt payment discount allowed except in cases where the outstanding bill is unusually high as a result of the utility's error (such as an inaccurately estimated bill or an incorrectly read meter). A deferred payment plan shall not include a finance charge.

(v) If a customer for utility service has not fulfilled terms of a deferred payment agreement or refuses to sign the same if it is reduced to writing, the utility shall have the right to disconnect pursuant to disconnection rules herein and, under such circumstances, it shall not be required to offer a subsequent negotiation of a deferred payment agreement prior to disconnection.

(vi) Any utility which institutes a deferred payment plan shall not refuse a customer participation in such a program on the basis of race, color, creed, sex, marital status, age, or any other form of discrimination prohibited by law.

(E) Delayed payment of bills by elderly persons.

(i) Applicability. This subparagraph applies only to:

(I) a utility that assesses late payment charges on residential customers and that suspends service before the 26th day after the date of the bill for which collection action is taken;

(II) utility bills issued on or after August 30, 1993; and

(III) an elderly person, as defined in clause (ii) of this subparagraph, who is a residential customer and who occupies the entire premises for which a delay is requested.

(ii) Definitions.

(I) Elderly person--A person who is 60 years of age or older.

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(II) Utility--A gas utility or municipally owned utility, as defined in Texas Utilities Code, §§101.003(7), 101.003(8), and 121.001 - 121.006.

(iii) An elderly person may request that the utility implement the delay for either the most recent utility bill or for the most recent utility bill and each subsequent utility bill.

(iv) On request of an elderly person, a utility shall delay without penalty the payment date of a bill for providing utility services to that person until the 25th day after the date on which the bill is issued.

(v) The utility may require the requesting person to present reasonable proof that the person is 60 years of age or older.

(vi) Every utility shall notify its customers of this delayed payment option no less often than yearly. A utility may include this notice with other information provided pursuant to subparagraph (A) of this paragraph.

(3) Refusal of service.

(A) Compliance by applicant. Any utility may decline to serve an applicant for whom service is available from previously installed facilities until such applicant has complied with the state and municipal regulations and approved rules and regulations of the utility on file with the commission governing the service applied for or for the following reasons.

(i) Applicant's facilities inadequate. If the applicant's installation or equipment is known to be hazardous or of such character that satisfactory service cannot be given.

(ii) For indebtedness. If the applicant is indebted to any utility for the same kind of service as that applied for; provided, however, that in the event the indebtedness of the applicant for service is in dispute, the applicant shall be served upon complying with the applicable deposit requirement.

(iii) Refusal to make deposit. For refusal to make a deposit if applicant is required to make a deposit under these rules.

(B) Applicant's recourse. In the event that the utility shall refuse to serve an applicant under the provisions of these rules, the utility must inform the applicant of the basis of its refusal and that the applicant may file a complaint with the municipal regulatory authority or commission, whichever is appropriate.

(C) Insufficient grounds for refusal to serve. The following shall not constitute sufficient cause for refusal of service to a present customer or applicant:

(i) delinquency in payment for service by a previous occupant of the premises to be served;

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(ii) failure to pay for merchandise or charges for nonutility service purchased from the utility;

(iii) failure to pay a bill to correct previous underbilling due to misapplication of rates more than six months prior to the date of application;

(iv) violation of the utility's rules pertaining to operation of nonstandard equipment or unauthorized attachments which interfere with the service of others unless the customer has first been notified and been afforded reasonable opportunity to comply with these rules;

(v) failure to pay a bill of another customer as guarantor thereof unless the guarantee was made in writing to the utility as a condition precedent to service; and

(vi) failure to pay the bill of another customer at the same address except where the change of customer identity is made to avoid or evade payment of a utility bill.

(4) Discontinuance of service.

(A) The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

(B) A utility may offer an inducement for prompt payment of bills by allowing a discount in the amount of 5.0% for payment of bills within 10 days after their issuance. This provision shall not apply where it conflicts with existing orders or ordinances of the appropriate regulatory authority.

(C) A customer's utility service may be disconnected if the bill has not been paid or a deferred payment plan pursuant to paragraph (2)(D) of this section has not been entered into within five working days after the bill has become delinquent and proper notice has been given. Proper notice consists of a deposit in the United States mail, postage prepaid, or hand delivery to the customer at least five working days prior to the stated date of disconnection, with the words "Termination Notice" or similar language prominently displayed on the notice. The notice shall be provided in English and Spanish as necessary to adequately inform the customer, and shall include the date of termination, the hours, address, and telephone number where payment may be made, and a statement that if a health or other emergency exists, the utility may be contacted concerning the nature of the emergency and the relief available, if any, to meet such emergency.

(D) Utility service may be disconnected for any of the following reasons:

(i) failure to pay a delinquent account or failure to comply with the terms of a deferred payment plan for installment payment of a delinquent account;

(ii) violation of the utility's rules pertaining to the use of service in a manner which interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has

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been made to notify the customer and the customer is provided with a reasonable opportunity to remedy the situation;

(iii) failure to comply with deposit or guarantee arrangements where required by paragraph (5) of this section;

(iv) without notice where a known dangerous condition exists for as long as the condition exists;

(v) tampering with the utility company's meter or equipment or bypassing the same.

(E) Utility service may not be disconnected for any of the following reasons:

(i) delinquency in payment for service by a previous occupant of the premises;

(ii) failure to pay for merchandise or charges for nonutility service by the utility;

(iii) failure to pay for a different type or class of utility service unless fee for such service is included on the same bill;

(iv) failure to pay the account of another customer as guarantor thereof, unless the utility has in writing the guarantee as a condition precedent to service;

(v) failure to pay charges arising from an underbilling occurring due to any misapplication of rates more than six months prior to the current billings;

(vi) failure to pay charges arising from an underbilling due to any faulty metering, unless the meter has been tampered with or unless such underbilling charges are due;

(vii) failure to pay an estimated bill other than a bill rendered pursuant to an approved meter reading plan, unless the utility is unable to read the meter due to circumstances beyond its control.

(F) Unless a dangerous condition exists, or unless the customer requests disconnection, service shall not be disconnected on a day, or on a day immediately preceding a day, when personnel of the utility are not available to the public for the purpose of making collections and reconnecting service.

(G) No utility may abandon a customer without written approval from the regulatory authority.

(H) No utility may discontinue service to a delinquent residential customer permanently residing in an individually metered dwelling unit when that customer establishes that discontinuance of service will result in some person residing at that residence becoming seriously ill or more seriously ill if the service is discontinued. Any customer seeking to avoid termination of service under this section must make a written request supported by a written statement from a licensed

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physician. Both the request and the statement must be received by the utility not more than five working days after the date of delinquency of the bill. The prohibition against service termination provided by this section shall last 20 days from the date of receipt by the utility of the request and statement or such lesser period as may be agreed upon by the utility and the customer. The customer who makes such request shall sign an installment agreement which provides for payment of such service along with timely payments for subsequent monthly billings.

(5) Applicant deposit.

(A) Establishment of credit for residential applicants. Each utility may require a residential applicant for service to satisfactorily establish credit but such establishment of credit shall not relieve the customer from complying with rules for prompt payment of bills. Subject to these rules, a residential applicant shall not be required to pay a deposit:

(i) if the residential applicant has been a customer of any utility for the same kind of service within the last two years and is not delinquent in payment of any such utility service account and during the last 12 consecutive months of service did not have more than one occasion in which a bill for such utility service was paid after becoming delinquent and never had service disconnected for nonpayment;

(ii) if the residential applicant furnishes in writing a satisfactory guarantee to secure payment of bills for the service required; or

(iii) if the residential applicant furnishes in writing a satisfactory credit rating by appropriate means, including, but not limited to, the production of generally acceptable credit cards, letters of credit reference, the names of credit references which may be quickly and inexpensively contacted by the utility, or ownership of substantial equity.

(B) Reestablishment of credit. Every applicant who has previously been a customer of the utility and whose service has been discontinued for nonpayment of bills shall be required before service is rendered to pay all his amounts due the utility or execute a written deferred payment agreement, if offered, and reestablish credit as provided in subparagraph (A) of this paragraph.

(C) Amount of deposit and interest for residential service, and exemption from deposit.

(i) Each gas utility shall waive any deposit requirement for residential service for an applicant who has been determined to be a victim of family violence as defined in Texas Family Code, §71.004, by a family violence center, by treating medical personnel, by law enforcement agency personnel, or by a designee of the Attorney General in the Crime Victim Services Division of the Office of the Attorney General. This determination shall be evidenced by the applicant's submission of a certification letter developed by the Texas Council on Family Violence and made available on its web site.

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(ii) The required deposit shall not exceed an amount equivalent to one-sixth of the estimated annual billings. If actual use is at least twice the amount of the estimated billings, a new deposit requirement may be calculated and an additional deposit may be required within two days. If such additional deposit is not made, the utility may disconnect service under the standard disconnection procedure for failure to comply with deposit requirements.

(iii) All applicants for residential service who are 65 years of age or older will be considered as having established credit if such applicant does not have an outstanding account balance with the utility or another utility for the same utility service which accrued within the last two years. No cash deposit shall be required of such applicant under these conditions.

(iv) Each utility which requires deposits to be made by its customers shall pay a minimum interest on such deposits according to the rate as established by law. If refund of deposit is made within 30 days of receipt of deposit, no interest payment is required. If the utility retains the deposit more than 30 days, payment of interest shall be made retroactive to the date of deposit.

(I) Payment of interest to the customer shall be annually or at the time the deposit is returned or credited to the customer's account.

(II) The deposit shall cease to draw interest on the date it is returned or credited to the customer's account.

(D) Deposits for temporary or seasonal service and for weekend or seasonal residences. The utility may require a deposit sufficient to reasonably protect it against the assumed risk, provided such a policy is applied in a uniform and nondiscriminatory manner.

(E) Records of deposits.

(i) The utility shall keep records to show:

(I) the name and address of each depositor;

(II) the amount and date of the deposit; and

(III) each transaction concerning the deposit.

(ii) The utility shall issue a receipt of deposit to each applicant from whom a deposit is received and shall provide means whereby a depositor may establish claim if the receipt is lost.

(iii) A record of each unclaimed deposit must be maintained for at least four years, during which time the utility shall make a reasonable effort to return the deposit.

(F) Refund of deposit.

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(i) If service is not connected or after disconnection of service, the utility shall promptly and automatically refund the customer's deposit plus accrued interest on the balance, if any, in excess of the unpaid bills for service furnished. The transfer of service from one premise to another within the service area of the utility shall not be deemed a disconnection within the meaning of these rules, and no additional deposit may be demanded unless permitted by these rules.

(ii) When the customer has paid bills for service for 12 consecutive residential bills without having service disconnected for nonpayment of bill and without having more than two occasions in which a bill was delinquent and when the customer is not delinquent in the payment of the current bills, the utility shall promptly and automatically refund the deposit plus accrued interest to the customer in the form of cash or credit to a customer's account.

(G) Upon sale or transfer of utility or company. Upon the sale or transfer of any public utility or operating units thereof, the seller shall file with the commission under oath, in addition to other information, a list showing the names and addresses of all customers served by such utility or unit who have to their credit a deposit, the date such deposit was made, the amount thereof, and the unpaid interest thereon.

(H) Complaint by applicant or customer. Each utility shall direct its personnel engaged in initial contact with an applicant or customer for service seeking to establish or reestablish credit under the provisions of these rules to inform the customer, if dissatisfaction is expressed with the utility's decision, of the customer's right to file a complaint with the regulatory authority thereon.

(6) Billing.

(A) Bills for gas service shall be rendered monthly, unless otherwise authorized or unless service is rendered for a period less than a month. Bills shall be rendered as promptly as possible following the reading of meters.

(B) The customer's bill must show all the following information. The information must be arranged and displayed in such a manner as to allow the customer to compute his bill with the applicable rate schedule. The applicable rate schedule must be mailed to the customer on request of the customer. A utility may exhaust its present stock of nonconforming bill forms before compliance is required by this section:

(i) if the meter is read by the utility, the date and reading of the meter at the beginning and end of the period for which rendered;

(ii) the number and kind of units billed;

(iii) the applicable rate schedule title or code;

(iv) the total base bill;

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- (v) the total of any adjustments to the base bill and the amount of adjustments per billing unit;
- (vi) the date by which the customer must pay the bill to get prompt payment discount;
- (vii) the total amount due before and after any discount for prompt payment within a designated period;
- (viii) a distinct marking to identify an estimated bill.

(C) Where there is good reason for doing so, estimated bills may be submitted, provided that an actual meter reading is taken at least every six months. For the second consecutive month in which the meter reader is unable to gain access to the premises to read the meter on regular meter reading trips, or in months where meters are not read otherwise, the utility must provide the customer with a postcard and request that the customer read the meter and return the card to the utility if the meter is of a type that can be read by the customer without significant inconvenience or special tools or equipment. If such a postcard is not received by the utility in time for billing, the utility may estimate the meter reading and render the bill accordingly.

(D) Disputed bills.

(i) In the event of a dispute between the customer and the utility regarding the bill, the utility must forthwith make such investigation as is required by the particular case and report the results thereof to the customer. If the customer wishes to obtain the benefits of clause (ii) of this subparagraph, notification of the dispute must be given to the utility prior to the date the bill becomes delinquent. In the event the dispute is not resolved, the utility shall inform the customer of the complaint procedures of the appropriate regulatory authority.

(ii) Notwithstanding any other subsection of this section, the customer shall not be required to pay the disputed portion of the bill which exceeds the amount of that customer's average usage for the billing period at current rates until the earlier of the following: resolution of the dispute or the expiration of the 60-day period beginning on the day the disputed bill is issued. For purposes of this section only, the customer's average usage for the billing period shall be the average of the customer's usage for the same billing period during the preceding two years. Where no previous usage history exists, the average usage shall be estimated on the basis of usage levels of similar customers and under similar conditions.

(7) Meters.

(A) Meter requirements.

(i) Use of meter. All gas sold by a utility must be charged for by meter measurements, except where otherwise provided for by applicable law, regulation of the regulatory authority, or tariff.

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(ii) Installation by utility. Unless otherwise authorized by the regulatory authority, each utility must provide and install and will continue to own and maintain all meters necessary for measurement of gas delivered to its customers.

(iii) Standard type. No utility may furnish, set up, or put in use any meter which is not reliable and of a standard type which meets generally accepted industry standards; provided, however, special meters not necessarily conforming to such standard types may be used for investigation, testing, or experimental purposes.

(B) Meter records. Each utility must keep the following records:

(i) Meter equipment records. Each utility must keep a record of all its meters, showing the customer's address and date of the last test.

(ii) Records of meter tests. All meter tests must be properly referenced to the meter record provided for therein. The record of each test made on request of a customer must show the identifying number and constants of the meter, the standard meter and other measuring devices used, the date and kind of test made, by whom made, the error (or percentage of accuracy) at each load tested, and sufficient data to permit verification of all calculations.

(iii) Meter readings--meter unit location. In general, each meter must indicate clearly the units of service for which charge is made to the customer.

(iv) Meter tests on request of customer.

(I) Each utility must, upon request of a customer, make a test of the accuracy of the meter serving that customer. The utility must inform the customer of the time and place of the test and permit the customer or his authorized representative to be present if the customer so desires. If no such test has been performed within the previous four years for the same customer at the same location, the test is to be performed without charge. If such a test has been performed for the same customer at the same location within the previous four years, the utility is entitled to charge a fee for the test not to exceed \$15 or such other fee for the testing of meters as may be set forth in the utility's tariff properly on file with the regulatory authority. The customer must be properly informed of the result of any test on a meter that serves him.

(II) Notwithstanding subclause (I) of this clause, if the meter is found to be more than nominally defective, to either the customer's or the utility's disadvantage, any fee charged for a meter test must be refunded to the customer. More than nominally defective means a deviation of more than 2.0% from accurate registration.

(v) Bill adjustments due to meter error.

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(I) If any meter test reveals a meter to be more than nominally defective, the utility must correct previous readings consistent with the inaccuracy found in the meter for the period of either:

(-a-) the last six months; or

(-b-) the last test of the meter, whichever is shorter. Any resulting underbillings or overbillings are to be corrected in subsequent bills, unless service is terminated, in which event a monetary adjustment is to be made. This requirement for a correction may be foregone by the utility if the error is to the utility's disadvantage.

(II) If a meter is found not to register for any period of time, the utility may make a charge for units used but not metered for a period not to exceed three months previous to the time the meter is found not to be registering. The determination of amounts used but not metered is to be based on consumption during other like periods by the same customer at the same location, when available, and on consumption under similar conditions at the same location or of other similarly situated customers, when not available.

(8) New construction.

(A) Standards of construction. Each utility is to construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with the provisions of such codes and standards as are generally accepted by the industry, as modified by rule or regulation of the regulatory authority or otherwise by law, and in such manner to best accommodate the public and to prevent interference with service furnished by other public utilities insofar as practical.

(B) Line extension and construction charges. Every utility must file its extension policy. The policy must be consistent, nondiscriminatory, and is subject to the approval of the regulatory authority. No contribution in aid of construction may be required of any customer except as provided for in extension policy.

(C) Response to request for service. Every gas utility must serve each qualified applicant for service within its service area as rapidly as practical. As a general policy, those applications not involving line extensions or new facilities should be filled within seven working days. Those applications for individual residential service requiring line extensions should be filled within 90 days unless unavailability of materials or other causes beyond the control of the utility result in unavoidable delays. In the event that residential service is delayed in excess of 90 days after an applicant has met credit requirements and made satisfactory arrangements for payment of any required construction charges, a report must be made to the regulatory authority listing the name of the applicant, location, and cause for delay. Unless such delays are due to causes which are reasonably beyond the control of the utility, a delay in excess of 90 days may be found to constitute a refusal to serve.

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RATE CASE EXPENSE SURCHARGE – ENVIRONS

APPLICABILITY

All jurisdictional customers in the unincorporated or environs areas of West Texas Gas Utility, LLC (“WTGU”) Service Area.

RCE RATE

Pursuant to the Final Order in Case No. OS-24-00017816, WTGU is authorized to recover a total not to exceed \$ ___ in rate case expenses from Case No. OS-24-00017816 jurisdictional customers by a surcharge applicable to all jurisdictional customers in incorporated and unincorporated areas at the rate of \$0. ___/Mcf for a period of approximately ___ months commencing _____.

COMPLIANCE

The Company shall file an annual rate case expense reconciliation report within 90 days after each calendar year end until and including the calendar year end in which the rate case expenses are fully recovered. The Company shall file the report with the Railroad Commission of Texas addressed to the Director of Oversight and Safety Division, Gas Services Department and referencing Case No. OS-024-00017816, Rate Case Expense Recovery Report. The report shall detail the monthly collections for RCE surcharge by customer class and show the outstanding balance. Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Compliance Filing
Director of Oversight and Safety Division
Gas Services Dept.
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

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RESIDENTIAL SERVICE RATE – ENVIRONS

APPLICABILITY

Applicable to a residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes in an unincorporated or environs area served by West Texas Gas Utility, LLC (“WTGU”). A residential consumer includes an individually-metered residential unit or dwelling and builders prior to sale or re-sale of a property for domestic purposes. This rate is only available to full requirements customers of WTGU.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Residential consumers per meter billing cycle or for any part of a billing cycle for which gas service is available at the same location.

Customer Charge \$29.50
All Consumption @ \$7.68 per Mcf

The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

OTHER FEES

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule Gas Cost Adjustment-ENV.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-ENV.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEES-ENV.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-ENV.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

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RATE SCHE

TAX-ENV

TAX ADJUSTMENT – ENVIRONS

REVENUE RELATED TAX ADJUSTMENT

Each monthly bill for a jurisdictional customer, as adjusted, shall also be adjusted by an amount equivalent to the various revenue related taxes, franchise fees, rentals, or other fees and charges imposed by regulatory or governmental authorities. This includes, but not limited to, Gross Receipts Taxes or any other governmental imposition, rental fee or charge levied that is based on any portion of revenues billed by West Texas Gas Utility, LLC.

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RATE SCHEDULE
WINTER STORM RIDER

WINTER STORM URI SURCHARGE

APPLICABILITY

All jurisdictional customers in the unincorporated or environs areas of West Texas Gas Utility, LLC (“WTGU”) Service Area.

PURPOSE

The purpose of the Winter Storm Uri Surcharge is to authorize WTGU to recover the reasonable, necessary, and prudent extraordinary gas costs incurred by WTGU as a result of Winter Storm Uri. The rate schedule is authorized by the Railroad Commission of Texas’s (“Commission”) Final Order in Case No. OS-24-00017816, which approved a Winter Storm Uri Regulatory Asset and the recovery of the costs contained in the regulatory asset through a monthly surcharge. WTGU is authorized and directed to assess the Winter Storm Uri Surcharge rate as set forth in the section below.

SURCHARGE RATE

All Mcf during each billing period: \$0.41 per Mcf.

This rate will be in effect until all approved and expended Winter Storm Uri costs, up to \$3,502,862.41 (“Regulatory Asset Amount”), are recovered under the applicable rate schedules. Any excess recovery of the Regulatory Asset Amount shall be calculated and refunded to customers through a final true-up under this rate schedule.

OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

CONDITIONS

1. Subject to all applicable laws and orders, and WTGU’s rules and regulations on file with the regulatory authority.
2. Uncollectible amounts, actually written off, associated with this surcharge shall be added back to the balance to be recovered via this surcharge.
3. Any amounts that were included in the Regulatory Asset Amount that are refunded to WTGU subsequent to the Final Order in Case No. OS-24-00017816 shall be subtracted from the balance and shall not be recovered via this surcharge.

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RATE SCHE
WINTER STORM RIDER

WINTER STORM URI SURCHARGE RECOVERY COMPLIANCE REPORT

WTGU shall file a reconciliation report annually on or before March 31, commencing in 2026 and ceasing after a reconciliation report is filed at the end of the month following the month in which the Regulatory Asset Amount is fully recovered via the final reconciliation true-up (if applicable). WTGU shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing Case No. OS-24-00017816, Winter Storm Uri Surcharge Recovery Report. The report shall include:

- The volumes used by month by customer class during the applicable period;
- The amount of surcharge recovered, by month;
- The outstanding balance, by month;
- The associated uncollectibles, by month; and
- Any credits for amounts WTGU received that would offset the Regulatory Asset Amount

Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Compliance Filing
Director of Oversight and Safety Division
Gas Services Dept.
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

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COMMERCIAL SERVICE RATE - INCORPORATED

APPLICABILITY

Applicable to all commercial customers and to customers not otherwise specifically provided for under any other rate schedule or served under a contract in an incorporated area or city served by West Texas Gas Utility, LLC (“WTGU”). This rate is only available to full requirements customers of WTGU.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Commercial consumers and to consumers not otherwise specifically provided for under any other rate schedule or served under a contract per meter billing cycle or for any part of a billing cycle for which gas service is available at the same location.

Customer Charge	\$79.00
All Consumption @	\$4.89 per Mcf

The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

OTHER FEES

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule Gas Cost Adjustment- INC.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE- INC.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee- INC.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provision of Rate Schedule MISCFEES- INC.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-INC.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

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RATE SCHE
GAS COST ADJUSTMENT-INC

GAS COST ADJUSTMENT – INCORPORATED

Applicability

This clause shall apply to all customers served by WTGU, except for customers purchasing gas at contract rates. Each customer's gas costs will be determined by the costs incurred in the applicable Gas Cost Zone. For purposes of determining gas purchase costs, all customers will be located in one of three Gas Cost Zones: North, South, and West. Each Gas Cost Zone consists of the following systems or geographic areas:

NORTH GAS COST ZONE:

Incorporated areas of the Cities of Amarillo, Cactus, Canadian, Canyon, Claude, Dalhart, Darrouzett, Farwell, Follett, Groom, Higgins, Miami, Mobeetic, Shamrock, Stratford, Texhoma, Texline, Wheeler and White Deer.

SOUTH GAS COST ZONE:

Incorporated areas of the Cities of Devine, Eden, Junction, La Vernia, Lockhart, Luling, Menard, Natalia, Paint Rock, Seguin, Somerset and Sonora.

WEST GAS COST ZONE:

Incorporated areas of the Cities of Balmorhea, Kermit, Lubbock, Van Horn, and Wolfforth.

Intent

This clause is intended to allow collection of West Texas Gas Utility, LLC ("WTGU") gas purchase costs in a manner that will lessen monthly fluctuations in the gas cost factor and ensure that all amounts billed to customers are fully reconciled with actual costs incurred, subject to limitations for excessive lost and unaccounted for gas.

Definitions

Gas Cost Zones – North, South, and West, as defined in the "Applicability" section below.

Interest – The percentage of interest shall be the interest rate established by the Public Utility Commission, or such other agency or manner as determined by the Commission, under Chapter 183 of the Texas Utilities Code.

Lost and Unaccounted For Gas – Lost and Unaccounted for Gas (LUG) shall represent volumes of gas metered into the distribution system and volumes of gas metered out of the distribution system at 14.65 p.s.i.a., which shall include distribution and non-distribution volumes. WTGU transmission LUG shall not be included in these volumes.

Purchased Gas Costs –The total cost of Purchase Volumes, as received into the Company's distribution systems within each Gas Cost Zone.

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GAS COST ADJUSTMENT-INC

Purchased Gas Factor (“PGF”) – A factor on each customer’s monthly bill, expressed in dollars per Mcf, to reflect the Purchase Gas Costs, all as more specifically described herein.

Purchase/Sales Ratio – A ratio determined by dividing the Company’s Purchase Volumes metered into the distribution system during the twelve-month period ending June 30 of each year by the sum of the Company’s Sales Volumes metered out of the distribution system, volumes of metered Company used gas, and losses of gas from the Company’s systems within each Gas Cost Zone that have been billed to third parties during the same period. Such ratio as determined shall in no event exceed 1.0526 i.e. $1/1(1-.05)$ unless expressly authorized by the applicable regulatory authority.

Purchase Volumes – The volumes of gas, expressed in Mcf’s and stated at 14.65 psia, received by the Company’s distribution system from all sources within each Gas Cost Zone, including monthly purchases and withdrawals from storage, if any, for use by general service customers. This quantity of gas shall not include LUG attributable to the WTGU Transmission System or transmission function.

Reconciliation Amount – The net of any monthly imbalances by Gas Cost Zone during the period covered by the Reconciliation Review.

Reconciliation Component – The monthly amount to be refunded or passed through to customers within each Gas Cost Zone, consisting of one-twelfth of the Reconciliation Amount.

Reconciliation Factor – A factor, expressed as a cost per Mcf on customer bills within each Gas Cost Zone, reflecting the customer’s share of the Reconciliation Component applicable to the period covered by the bill.

Reconciliation Review – An annual review of the Company’s records covering each 12-month period ending June 30 to determine any imbalances between the Purchase Gas Cost and the Sales Amount as applied to each Gas Cost Zone during that period.

Sales Amount – Sales Volumes, volumes of metered Company used gas, and losses of gas from the Company’s system within each Gas Cost Zone that have been billed to third parties, multiplied by the Purchased Gas Factor.

Sales Volumes – The volumes of gas metered to general service customers within each Gas Cost Zone expressed in Mcf’s and stated at 14.65 psia.

Weighted Average Cost of Gas – The Purchase Gas Costs invoiced by third parties divided by the Purchase Volumes, calculated on a monthly basis for each Gas Cost Zone

Purchase Gas Cost Component (PGC)

The Purchase Gas Cost for each Gas Cost Zone shall be computed utilizing the following components for the distribution system customers:

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**RATE SCHE
GAS COST ADJUSTMENT-INC**

- Cost of gas purchased
- Credits, Refunds or Out of Period adjustments
- Cost of gas withdrawn from storage
- Interest on storage gas withdrawn
- Upstream Gathering and Transportation Charges
- Storage Deliverability Charges
- Storage Capacity Charges
- New taxes on the purchased gas or the purchase transaction and not reflected on elsewhere on customer bills

WTGU shall keep accurate records of all storage gas purchases, including the date, quantity, cost, and associated expenses. WTGU shall account for storage gas purchases and withdrawals using a weighted average cost basis.

Purchased Gas Factor (PGF) Calculation

Each customer bill shall include a Purchased Gas Factor reflecting the estimated Weighted Average Cost of Gas, plus additional elements described in this section, during the period covered by the bill for each Gas Cost Zone. The PGF shall be determined to the nearest \$0.001 per Mcf, and the following provisions shall apply:

- In addition to the estimated weighted average cost of gas for the current month’s billing period, the PGF may include a pro rata portion of an amount reflecting the difference between the estimated Weighted Average Cost of Gas and the actual Weighted Average Cost of Gas during the previous billing period for each Gas Cost Zone
- The PGF shall also include a “Reconciliation Factor,” an amount reflecting the customer’s share of any gas cost imbalances in the preceding reconciliation period for each Gas Cost Zone.
- The PGF factor may also include an amount reflecting any new taxes or levies specifically applied to gas costs or purchases and not otherwise reflected on the customer bill for each Gas Cost Zone.

The Purchased Gas Factor is expressed as a formula as follows:

$$(A+/-B) + C + D = E$$

Where:

- | | |
|--------------------------------------|---------------------------|
| A = Estimated WACOG | C = Reconciliation Factor |
| B = Est. WACOG/Act. WACOG Difference | D = New Taxes |
| | E = Total PGF |

Gas Cost Reconciliation (GCR)

WTGU shall keep accurate books and records of the Reconciliation Review, monthly Purchased Gas Factor reports to the Railroad Commission of Texas, and shall account for the Reconciliation Component and the Reconciliation Factors for each Gas Cost Zone.

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A Reconciliation Review and calculation shall first determine whether the lost and unaccounted for gas is more or less than 5% of that metered into the system. The sales volumes shall be converted to the same pressure base as the purchase volumes. Calculations of the sales volumes furnished to its gas sales customers (from meters not corrected for pressure and/or temperature) shall be calculated utilizing the following service pressures (psia):

Incorporated areas of the Cities of:

Amarillo	13.38	Higgins	13.78	Shamrock	13.88
Balmorhea	13.48	Junction	14.18	Somerset	14.68
Cactus	13.28	Kermit	13.68	Sonora	13.98
Canadian	13.88	La Vernia	14.68	Stratford	13.18
Canyon	13.45	Lockhart	14.68	Texhoma	13.38
Claude	13.38	Lubbock	13.45	Texline	12.98
Dalhart	13.07	Luling	14.68	Van Horn	13.48
Darrouzett	13.78	Menard	14.08	Wheeler	13.78
Devine	14.68	Miami	13.68	White Deer	13.38
Eden	14.08	Mobeetie	13.78	Wolfforth	13.45
Farwell	13.18	Natalia	14.68		
Follett	13.68	Paint Rock	14.28		
Groom	13.38	Seguin	14.68		

If the Reconciliation Review indicates a gas loss or gas gain of less than 5% of that metered into the system, the following methodology shall apply:

- WTGU shall calculate the imbalance between its Net Jurisdictional Cost of Gas and amount collected through the PGA billed on a monthly basis for said Gas Cost Zone. The Net Jurisdictional Cost of Gas shall be calculated by multiplying the Total Jurisdictional Sales Volumes by the Actual P/S Ratio to arrive at the Calculated Purchased Volume. The Calculated Purchased Volume is then multiplied by the WACOG to arrive at the Net Jurisdictional Cost of Gas.
- Interest shall be applied to each monthly imbalance for said Gas Cost Zone and shall accrue for each month of the review period.
- The interest rate shall be the same rate as determined by the Public Utility Commission of Texas for refunds on customer deposits and in effect during the last month of the audit period (June).
- The sum of the monthly imbalances, plus interest, for each Gas Cost Zone for the period under review shall be the Reconciliation Amount, the total amount to be refunded/surcharged in said Gas Cost Zone.

If the Reconciliation Review indicates a gas loss or gas gain of greater than 5% of that metered into the system, the following methodology shall apply:

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- WTGU shall calculate the imbalance between its Purchase Gas Cost and Sales Amount on a monthly basis for said Gas Cost Zones Purchase Gas Cost amounts in excess of the 1.0526 ratio shall be disallowed by:
 - 1) Dividing total Purchase Volumes for the 12-month review period by the total Sales Volumes for the same period in said Gas Cost Zone.
 - 2) Subtracting that result from 1, which when expressed as a percentage, becomes said Gas Cost Zones “Actual P/S Ratio.”
 - 3) Subtracting 5.26% from said Gas Cost Zones Actual P/S Ratio, results in a “Disallowance Factor” for the review period.
 - 4) Multiplying the Disallowance Factor by the Purchase Volumes for each month and by the Weighted Average Cost of Gas for each month, for said Gas Cost Zone will result in an amount to be disallowed each month.
 - 5) The Net Jurisdictional Cost of Gas shall be calculated by multiplying the Total Jurisdictional Sales Volume by the Actual P/S Ratio to arrive at the Calculated Purchased Volume. The Calculated Purchased Volume is then multiplied by the WACOG to arrive at the Jurisdictional Cost of Gas. The Net Jurisdictional Cost of Gas is calculated by subtracting the Disallowed Amount calculated above.
- Interest shall be applied to each monthly imbalance for said Gas Cost Zone and shall accrue for each month of the review period.
- The interest rate shall be the rate in effect during the last month of the audit period (June).
- The sum of the monthly imbalances, plus interest, for the period under review shall be the Reconciliation Amount for said Gas Cost Zone or the total amount to be refunded/surcharged.

Reconciliation Factor Calculation (RFC)

The Reconciliation Amount for each Gas Cost Zone shall be divided by 12, resulting in the Reconciliation Component.

The Reconciliation Component shall be reflected in a refund or surcharge on each customer bill, according to Gas Cost Zone, over a twelve-month period beginning with the first billing cycle in September following the period covered by the review.

The Reconciliation Component for each month of the reconciliation period shall be calculated by dividing the Reconciliation Amount by the estimated Sales Volumes for the applicable billing period. The result will be a monthly Reconciliation Factor, expressed in Mcf for each Gas Cost Zone. Any under or over collection from the prior month may be factored in subsequent months' Reconciliation Component.

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Each month during the reconciliation period, the PGF for each Gas Cost Zone on customer bills shall be increased or reduced by the product of the number of Mcf billed to the customer and the monthly Reconciliation Factor, as indicated in the section of PGF calculations. Any under or over collections remaining at the end of the gas reconciliation period will be carried forward to the next gas reconciliation period.

MISCELLANEOUS FEES AND DEPOSITS – INCORPORATED

APPLICABILITY

Applicable to Residential, Commercial, Industrial, and any other jurisdictional customers of West Texas Gas Utility, LLC (“WTGU”) who are in an incorporated area or city served by WTGU.

FEES

Initiation of Service:

a) Connection Charge

The following connection charges apply:

<u>Schedule</u>	<u>Charge</u>
Business Hours (8AM to 5PM, Monday – Friday, except holidays)	\$50.00
After Hours (All Hours not associated with Business Hours)	\$70.00

A connect fee will be charged to any applicant for the cost involved in initiation of service. This fee shall be charged when a meter is set and/or gas turned on.

b) Read-In for Change Charge

A read-in fee of \$20.00 will be charged to any applicant for the cost involved in initiation of service. This fee shall be charged when only a meter reading is required.

c) After Hours & Special Handling

In addition to initiation of service fee above, a fee shall be charged to any applicant whose request to initiate service cannot be completed during normal business hours or requires special handling. Applicant shall be advised that an additional fee will be charged and must agree to pay such charge. Any fees assessed will reflect actual time incurred at \$20 per hour during business hours and \$30 per hour for after hours, plus the actual cost of materials and any incidental (third party) expenses. A third party is any person or entity, including an affiliate of the Company.

- (i) **Special Handling:** West Texas Gas Utility, LLC (“WTGU”) may, at customer’s request, provide special handling in order to meet the Customer’s requirements for a fee based on the rates indicated in (c) above. Special handling may include such assistance as calling the customer in advance or making other special arrangements (such as A.M. or P.M. scheduling) for access to the customer’s premises.

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- (ii) **Expedited Service:** If the customer requires that the order be worked after hours for their convenience or if the customer requires expedited service, the charge shall be based on the rates indicated in (c) above for after-hours service work on customer premises. The Customer’s request for expedited service may then be scheduled at any time to fit WTGU’s work schedule but the after-hours charge shall be collected as long as any other work is done on overtime.
- (iii) **Special Call Out:** If the initiation of service order requires special call out, the customer shall be charged based on the rates indicated in (c) above for after-hours service work on customer’s premises.

Customer Requested Meter Test

Whenever WTGU is requested by a customer to have a meter test performed, and the result of that meter test indicates that the meter is within 2% accuracy and the meter has been tested within a four year period from the time the customer made the request the customer will be charged according to the following fee schedule.

Positive Displacement	Charge
275 cubic feet per hour or less	\$25.00
276 to 1500 cubic feet per hour	\$30.00
1501 to 3000 cubic feet per hour	\$35.00
3001 to 5000 cubic feet per hour	\$45.00
over 5000 cubic feet per hour	\$60.00
Orifice Meters	
All sizes	\$40.00

The meter test fees schedule above will not apply when the test results indicate the meter is outside of the allowed 2% accuracy range.

Returned Check/Bank Draft Charges

Accounts for which payment is made using checks or electronic drafts which are returned or denied by a bank for any reason may be charged a fee for each occurrence of \$25.00.

Collection Fee

A fee of \$20.00 will be charged to any customer whose failure to respond to a termination notice necessitates the dispatch of a Company representative who attempts collection of payment from customer.

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Reconnect Fees

The following reconnection fees will be charged to any customer whose service is terminated and then re-initiated unless terminated in error by WTGU.

<u>Schedule</u>	<u>Charge</u>
Business Hours (8AM to 5PM, Monday – Friday, except holidays)	\$50.00
After Hours (All Hours not associated with Business Hours)	\$70.00

Temporary Service

Customers will be charged the actual cost of installation and removal of pipe and metering facilities. The actual cost will be calculated in accordance with the rates specified in Section 4.1.1 (c) above. This service does not include extension of mains.

Special Read

Customer requested reading of a meter for any purpose other than initiation of service will be charged \$20.00

No Access

A fee of \$20.00 will be charged to customer who schedules an appointment but fails to appear or Company personnel cannot access property to perform the service requested.

Tampering

Customers who tamper with their meters will be assessed a charge of \$150.00 plus the actual cost of any estimated volumes of gas illegally consumed or improperly measured based on such tampering, and the actual cost of time and materials to repair meters or other company equipment. The actual costs will be based on the labor rates and costs specified in Section 4.1.1 (c) above. This charge is not intended to duplicate any charge that may be imposed by the Texas Penal Code.

Extension Fee

In the event the cost of extending mains in an incorporated area exceeds the free limit established by the Franchise Agreement for domestic and non-domestic customers in the area, customers shall pay the actual cost of the extension, based on costs calculated in accordance with the rates specified in Section 4.1.1 (c) above, less the free limit. In the event the Franchise Agreement does not establish a free limit, and in all unincorporated areas, the customers shall pay the actual cost of the extension, less a \$150.00 credit, based on costs calculated in accordance with the rates specified in Section 4.1.1 (c) above.

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DEPOSITS

Customer Deposits

Deposits will be based on 1/6 of the customers estimated annual usage. For any customer who pays bills by electronic transfer to WTGU, these deposits will be based on 1/12 of the customers estimated annual usage.

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**NON-PROFIT INCORPORATED
SERVICE RATE**

APPLICABILITY

Applicable to all non-profit customers.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Non-Profit consumers.

Customer Charge \$79.00
All Consumption @ \$4.89 per Mcf

The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

OTHER FEES

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule Gas Cost Adjustment-INC.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-INC.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-INC.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provision of Rate Schedule MISCFEES-INC.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-INC.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

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OTHER SURCHARGES – INCORPORATED

West Texas Gas Utility, LLC will recover other surcharges from jurisdictional customers as authorized by federal, state and local regulatory authorities in accordance with applicable statutes, laws, regulations, ordinances, orders, rules, contracts or agreements.

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PIPELINE SAFETY FEE

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**PIPELINE SAFETY AND REGULATORY PROGRAM
RATE SCHEDULE**

Pipeline Safety and Regulatory Program Rate Schedule.

Applicability

Fee. Once annually, West Texas Gas Utility, LLC (“WTGU”) shall remit to the Commission the fee required in 16 TEX. ADMIN. CODE Section 8.201.

Surcharge. During the next billing cycle following WTGU remittance to the Commission of the fee, WTGU shall include on its customers’ bills a Pipeline Safety and Regulatory Program Surcharge, to the extent authorized in 16 TEX. ADMIN. CODE Section 8.201.

Formula. The Rule 8.201 surcharge is calculated in accordance with the following formula:

Rule 8.201(b) fee assessed by the Commission on WTGU
Divided by
Number of meters billed
Equals
Rule 8.201(b)(3) surcharge, applied per customer meter, once annually.

In this formula, the number of meters billed refers to the number of meters billed during the billing month that precedes the month the Rule 8.201(b)(3) surcharge is included on customer bills.

Compliance Report.

The Company shall file an annual pipeline safety fee (PSF) report no later than 90 days after the last billing cycle in which the pipeline safety and regulatory program fee surcharge is billed to customers. The Company shall file the report with the Railroad Commission of Texas addressed to the Director of Oversight and Safety Division, Gas Services Department, referencing Case No. OS-24-00017816, and titling the report “Pipeline Safety Fee Recovery Report”. The report shall include the following:

- a) the pipeline safety fee-amount paid to the Commission;
- b) the unit rate and total amount of the surcharge billed to each customer;
- c) the date or dates the surcharge was billed to customers; and
- d) the total amount collected from customers from the surcharge.

Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Compliance Filing
Director of Oversight and Safety Division
Gas Services Dept.
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

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PUBLIC AUTHORITY SERVICE RATE - INCORPORATED

APPLICABILITY

Applicable to all public authority customers.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Public Authority consumers.

Customer Charge	\$79.00
All Consumption @	\$4.89 per Mcf

The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

OTHER FEES

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule Gas Cost Adjustment-INC.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-INC.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-INC.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provision of Rate Schedule MISCFEE-INC.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-INC.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

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**INCORPORATED
QUALITY OF SERVICE RULES
RATE SCHEDULE**

RULE §7.45 Quality of Service

For gas utility service to residential and small commercial customers, the following minimum service standards shall be applicable in unincorporated areas. In addition, each gas distribution utility is ordered to amend its service rules to include said minimum service standards within the utility service rules applicable to residential and small commercial customers within incorporated areas, but only to the extent that said minimum service standards do not conflict with standards lawfully established within a particular municipality for a gas distribution utility. Said gas distribution utility shall file service rules incorporating said minimum service standards with the Railroad Commission and with the municipalities in the manner prescribed by law.

(1) Continuity of service.

(A) Service interruptions.

(i) Every gas utility shall make all reasonable efforts to prevent interruptions of service. When interruptions occur, the utility shall reestablish service within the shortest possible time consistent with prudent operating principles so that the smallest number of customers are affected.

(ii) Each utility shall make reasonable provisions to meet emergencies resulting from failure of service, and each utility shall issue instructions to its employees covering procedures to be followed in the event of an emergency in order to prevent or mitigate interruption or impairment of service.

(iii) In the event of national emergency or local disaster resulting in disruption of normal service, the utility may, in the public interest, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

(B) Record of interruption. Except for momentary interruptions which do not cause a major disruption of service, each utility shall keep a complete record of all interruptions, both emergency and scheduled. This record shall show the cause of interruptions, date, time duration, location, approximate number of customers affected, and, in cases of emergency interruptions, the remedy and steps taken to prevent recurrence.

(C) Report to commission. The commission shall be notified in writing within 48 hours of interruptions in service affecting the entire system or any major division thereof lasting more than four hours. The notice shall also state the cause of such interruptions. If any service interruption is

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reported to the commission otherwise (for example, as a curtailment report or safety report), such other report is sufficient to comply with the terms of this paragraph.

(2) Customer relations.

(A) Information to customers. Each utility shall:

(i) maintain a current set of maps showing the physical locations of its facilities. All distribution facilities shall be labeled to indicate the size or any pertinent information which will accurately describe the utility's facilities. These maps, or such other maps as may be required by the regulatory authority, shall be kept by the utility in a central location and will be available for inspection by the regulatory authority during normal working hours. Each business office or service center shall have available up-to-date maps, plans, or records of its immediate area, with such other information as may be necessary to enable the utility to advise applicants and others entitled to the information as to the facilities available for serving that locality;

(ii) assist the customer or applicant in selecting the most economical rate schedule;

(iii) in compliance with applicable law or regulations, notify customers affected by a change in rates or schedule or classification;

(iv) post a notice in a conspicuous place in each business office of the utility where applications for service are received informing the public that copies of the rate schedules and rules relating to the service of the utility as filed with the commission are available for inspection;

(v) upon request inform its customers as to the method of reading meters;

(vi) provide to new customers, at the time service is initiated or as an insert in the first billing, a pamphlet or information packet containing the following information. This information shall be provided in English and Spanish as necessary to adequately inform the customers; provided, however, the regulatory authority upon application and a showing of good cause may exempt the utility from the requirement that the information be provided in Spanish:

(I) the customer's right to information concerning rates and services and the customer's right to inspect or obtain at reproduction cost a copy of the applicable tariffs and service rules;

(II) the customer's right to have his or her meter checked without charge under paragraph (7) of this section, if applicable;

(III) the time allowed to pay outstanding bills;

(IV) grounds for termination of service;

(V) the steps the utility must take before terminating service;

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(VI) how the customer can resolve billing disputes with the utility and how disputes and health emergencies may affect termination of service;

(VII) information on alternative payment plans offered by the utility;

(VIII) the steps necessary to have service reconnected after involuntary termination;

(IX) the appropriate regulatory authority with whom to register a complaint and how to contact such authority;

(X) the hours, addresses, and telephone numbers of utility offices where bills may be paid and information may be obtained; and

(XI) the customer's right to be instructed by the utility how to read his or her meter;

(vii) at least once each calendar year, notify customers that information is available upon request, at no charge to the customer, concerning the items listed in clause (vi)(I) - (XI) of this subparagraph. This notice may be accomplished by use of a billing insert or a printed statement upon the bill itself.

(B) Customer complaints. Upon complaint to the utility by residential or small commercial customers either at its office, by letter, or by telephone, the utility shall promptly make a suitable investigation and advise the complainant of the results thereof. It shall keep a record of all complaints which shall show the name and address of the complainant, the date and nature of the complaint, and the adjustment or disposition thereof for a period of one year subsequent to the final disposition of the complaint.

(C) Utility response. Upon receipt of a complaint, either by letter or by telephone, from the regulatory authority on behalf of a customer, the utility shall make a suitable investigation and advise the regulatory authority and complainant of the results thereof. An initial response must be made by the next working day. The utility must make a final and complete response within 15 days from the date of the complaint, unless additional time is granted within the 15-day period. The commission encourages all customer complaints to be made in writing to assist the regulatory authority in maintaining records of the quality of service of each utility; however, telephone communications will be acceptable.

(D) Deferred payment plan. The utility is encouraged to offer a deferred payment plan for delinquent residential accounts. If such a plan is offered, it shall conform to the following guidelines:

(i) Every deferred payment plan entered into due to the customer's inability to pay the outstanding bill in full must provide that service will not be discontinued if the customer pays

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current bills and a reasonable amount of the outstanding bill and agrees to pay the balance in reasonable installments until the bill is paid.

(ii) For purposes of determining reasonableness under these rules, the following shall be considered: size of delinquent account; customer's ability to pay; customer's payment history; time that the debt has been outstanding; reasons why debt has been outstanding; and other relevant factors concerning the circumstances of the customer.

(iii) A deferred payment plan, if reduced to writing, offered by a utility shall state, immediately preceding the space provided for the customer's signature and in bold-face print at least two sizes larger than any other used, that: "If you are not satisfied with this agreement, do not sign. If you are satisfied with this agreement, you give up your right to dispute the amount due under the agreement except for the utility's failure or refusal to comply with the terms of this agreement."

(iv) A deferred payment plan may include a one-time 5.0% penalty for late payment on the original amount of the outstanding bill with no prompt payment discount allowed except in cases where the outstanding bill is unusually high as a result of the utility's error (such as an inaccurately estimated bill or an incorrectly read meter). A deferred payment plan shall not include a finance charge.

(v) If a customer for utility service has not fulfilled terms of a deferred payment agreement or refuses to sign the same if it is reduced to writing, the utility shall have the right to disconnect pursuant to disconnection rules herein and, under such circumstances, it shall not be required to offer a subsequent negotiation of a deferred payment agreement prior to disconnection.

(vi) Any utility which institutes a deferred payment plan shall not refuse a customer participation in such a program on the basis of race, color, creed, sex, marital status, age, or any other form of discrimination prohibited by law.

(E) Delayed payment of bills by elderly persons.

(i) Applicability. This subparagraph applies only to:

(I) a utility that assesses late payment charges on residential customers and that suspends service before the 26th day after the date of the bill for which collection action is taken;

(II) utility bills issued on or after August 30, 1993; and

(III) an elderly person, as defined in clause (ii) of this subparagraph, who is a residential customer and who occupies the entire premises for which a delay is requested.

(ii) Definitions.

(I) Elderly person--A person who is 60 years of age or older.

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(II) Utility--A gas utility or municipally owned utility, as defined in Texas Utilities Code, §§101.003(7), 101.003(8), and 121.001 - 121.006.

(iii) An elderly person may request that the utility implement the delay for either the most recent utility bill or for the most recent utility bill and each subsequent utility bill.

(iv) On request of an elderly person, a utility shall delay without penalty the payment date of a bill for providing utility services to that person until the 25th day after the date on which the bill is issued.

(v) The utility may require the requesting person to present reasonable proof that the person is 60 years of age or older.

(vi) Every utility shall notify its customers of this delayed payment option no less often than yearly. A utility may include this notice with other information provided pursuant to subparagraph (A) of this paragraph.

(3) Refusal of service.

(A) Compliance by applicant. Any utility may decline to serve an applicant for whom service is available from previously installed facilities until such applicant has complied with the state and municipal regulations and approved rules and regulations of the utility on file with the commission governing the service applied for or for the following reasons.

(i) Applicant's facilities inadequate. If the applicant's installation or equipment is known to be hazardous or of such character that satisfactory service cannot be given.

(ii) For indebtedness. If the applicant is indebted to any utility for the same kind of service as that applied for; provided, however, that in the event the indebtedness of the applicant for service is in dispute, the applicant shall be served upon complying with the applicable deposit requirement.

(iii) Refusal to make deposit. For refusal to make a deposit if applicant is required to make a deposit under these rules.

(B) Applicant's recourse. In the event that the utility shall refuse to serve an applicant under the provisions of these rules, the utility must inform the applicant of the basis of its refusal and that the applicant may file a complaint with the municipal regulatory authority or commission, whichever is appropriate.

(C) Insufficient grounds for refusal to serve. The following shall not constitute sufficient cause for refusal of service to a present customer or applicant:

(i) delinquency in payment for service by a previous occupant of the premises to be served;

(ii) failure to pay for merchandise or charges for nonutility service purchased from the utility;

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(iii) failure to pay a bill to correct previous underbilling due to misapplication of rates more than six months prior to the date of application;

(iv) violation of the utility's rules pertaining to operation of nonstandard equipment or unauthorized attachments which interfere with the service of others unless the customer has first been notified and been afforded reasonable opportunity to comply with these rules;

(v) failure to pay a bill of another customer as guarantor thereof unless the guarantee was made in writing to the utility as a condition precedent to service; and

(vi) failure to pay the bill of another customer at the same address except where the change of customer identity is made to avoid or evade payment of a utility bill.

(4) Discontinuance of service.

(A) The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

(B) A utility may offer an inducement for prompt payment of bills by allowing a discount in the amount of 5.0% for payment of bills within 10 days after their issuance. This provision shall not apply where it conflicts with existing orders or ordinances of the appropriate regulatory authority.

(C) A customer's utility service may be disconnected if the bill has not been paid or a deferred payment plan pursuant to paragraph (2)(D) of this section has not been entered into within five working days after the bill has become delinquent and proper notice has been given. Proper notice consists of a deposit in the United States mail, postage prepaid, or hand delivery to the customer at least five working days prior to the stated date of disconnection, with the words "Termination Notice" or similar language prominently displayed on the notice. The notice shall be provided in English and Spanish as necessary to adequately inform the customer, and shall include the date of termination, the hours, address, and telephone number where payment may be made, and a statement that if a health or other emergency exists, the utility may be contacted concerning the nature of the emergency and the relief available, if any, to meet such emergency.

(D) Utility service may be disconnected for any of the following reasons:

(i) failure to pay a delinquent account or failure to comply with the terms of a deferred payment plan for installment payment of a delinquent account;

(ii) violation of the utility's rules pertaining to the use of service in a manner which interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has been made to notify the customer and the customer is provided with a reasonable opportunity to remedy the situation;

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(iii) failure to comply with deposit or guarantee arrangements where required by paragraph (5) of this section;

(iv) without notice where a known dangerous condition exists for as long as the condition exists;

(v) tampering with the utility company's meter or equipment or bypassing the same.

(E) Utility service may not be disconnected for any of the following reasons:

(i) delinquency in payment for service by a previous occupant of the premises;

(ii) failure to pay for merchandise or charges for nonutility service by the utility;

(iii) failure to pay for a different type or class of utility service unless fee for such service is included on the same bill;

(iv) failure to pay the account of another customer as guarantor thereof, unless the utility has in writing the guarantee as a condition precedent to service;

(v) failure to pay charges arising from an underbilling occurring due to any misapplication of rates more than six months prior to the current billings;

(vi) failure to pay charges arising from an underbilling due to any faulty metering, unless the meter has been tampered with or unless such underbilling charges are due;

(vii) failure to pay an estimated bill other than a bill rendered pursuant to an approved meter reading plan, unless the utility is unable to read the meter due to circumstances beyond its control.

(F) Unless a dangerous condition exists, or unless the customer requests disconnection, service shall not be disconnected on a day, or on a day immediately preceding a day, when personnel of the utility are not available to the public for the purpose of making collections and reconnecting service.

(G) No utility may abandon a customer without written approval from the regulatory authority.

(H) No utility may discontinue service to a delinquent residential customer permanently residing in an individually metered dwelling unit when that customer establishes that discontinuance of service will result in some person residing at that residence becoming seriously ill or more seriously ill if the service is discontinued. Any customer seeking to avoid termination of service under this section must make a written request supported by a written statement from a licensed physician. Both the request and the statement must be received by the utility not more than five working days after the date of delinquency of the bill. The prohibition against service termination provided by this section shall last 20 days from the date of receipt by the utility of the request and statement or such lesser period as may be agreed upon by the utility and the customer. The

WEST TEXAS GAS UTILITY, LLC**Page 8 of 13****Effective:** _____

customer who makes such request shall sign an installment agreement which provides for payment of such service along with timely payments for subsequent monthly billings.

(5) Applicant deposit.

(A) Establishment of credit for residential applicants. Each utility may require a residential applicant for service to satisfactorily establish credit but such establishment of credit shall not relieve the customer from complying with rules for prompt payment of bills. Subject to these rules, a residential applicant shall not be required to pay a deposit:

(i) if the residential applicant has been a customer of any utility for the same kind of service within the last two years and is not delinquent in payment of any such utility service account and during the last 12 consecutive months of service did not have more than one occasion in which a bill for such utility service was paid after becoming delinquent and never had service disconnected for nonpayment;

(ii) if the residential applicant furnishes in writing a satisfactory guarantee to secure payment of bills for the service required; or

(iii) if the residential applicant furnishes in writing a satisfactory credit rating by appropriate means, including, but not limited to, the production of generally acceptable credit cards, letters of credit reference, the names of credit references which may be quickly and inexpensively contacted by the utility, or ownership of substantial equity.

(B) Reestablishment of credit. Every applicant who has previously been a customer of the utility and whose service has been discontinued for nonpayment of bills shall be required before service is rendered to pay all his amounts due the utility or execute a written deferred payment agreement, if offered, and reestablish credit as provided in subparagraph (A) of this paragraph.

(C) Amount of deposit and interest for residential service, and exemption from deposit.

(i) Each gas utility shall waive any deposit requirement for residential service for an applicant who has been determined to be a victim of family violence as defined in Texas Family Code, §71.004, by a family violence center, by treating medical personnel, by law enforcement agency personnel, or by a designee of the Attorney General in the Crime Victim Services Division of the Office of the Attorney General. This determination shall be evidenced by the applicant's submission of a certification letter developed by the Texas Council on Family Violence and made available on its web site.

(ii) The required deposit shall not exceed an amount equivalent to one-sixth of the estimated annual billings. If actual use is at least twice the amount of the estimated billings, a new deposit requirement may be calculated and an additional deposit may be required within two days. If such

WEST TEXAS GAS UTILITY, LLC**Page 9 of 13****Effective:** _____

additional deposit is not made, the utility may disconnect service under the standard disconnection procedure for failure to comply with deposit requirements.

(iii) All applicants for residential service who are 65 years of age or older will be considered as having established credit if such applicant does not have an outstanding account balance with the utility or another utility for the same utility service which accrued within the last two years. No cash deposit shall be required of such applicant under these conditions.

(iv) Each utility which requires deposits to be made by its customers shall pay a minimum interest on such deposits according to the rate as established by law. If refund of deposit is made within 30 days of receipt of deposit, no interest payment is required. If the utility retains the deposit more than 30 days, payment of interest shall be made retroactive to the date of deposit.

(I) Payment of interest to the customer shall be annually or at the time the deposit is returned or credited to the customer's account.

(II) The deposit shall cease to draw interest on the date it is returned or credited to the customer's account.

(D) Deposits for temporary or seasonal service and for weekend or seasonal residences. The utility may require a deposit sufficient to reasonably protect it against the assumed risk, provided such a policy is applied in a uniform and nondiscriminatory manner.

(E) Records of deposits.

(i) The utility shall keep records to show:

(I) the name and address of each depositor;

(II) the amount and date of the deposit; and

(III) each transaction concerning the deposit.

(ii) The utility shall issue a receipt of deposit to each applicant from whom a deposit is received and shall provide means whereby a depositor may establish claim if the receipt is lost.

(iii) A record of each unclaimed deposit must be maintained for at least four years, during which time the utility shall make a reasonable effort to return the deposit.

(F) Refund of deposit.

(i) If service is not connected or after disconnection of service, the utility shall promptly and automatically refund the customer's deposit plus accrued interest on the balance, if any, in excess of the unpaid bills for service furnished. The transfer of service from one premise to another within

WEST TEXAS GAS UTILITY, LLC

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RATE SCHE

Section 7, Item A.

QSR-INC

the service area of the utility shall not be deemed a disconnection within the meaning of these rules, and no additional deposit may be demanded unless permitted by these rules.

(ii) When the customer has paid bills for service for 12 consecutive residential bills without having service disconnected for nonpayment of bill and without having more than two occasions in which a bill was delinquent and when the customer is not delinquent in the payment of the current bills, the utility shall promptly and automatically refund the deposit plus accrued interest to the customer in the form of cash or credit to a customer's account.

(G) Upon sale or transfer of utility or company. Upon the sale or transfer of any public utility or operating units thereof, the seller shall file with the commission under oath, in addition to other information, a list showing the names and addresses of all customers served by such utility or unit who have to their credit a deposit, the date such deposit was made, the amount thereof, and the unpaid interest thereon.

(H) Complaint by applicant or customer. Each utility shall direct its personnel engaged in initial contact with an applicant or customer for service seeking to establish or reestablish credit under the provisions of these rules to inform the customer, if dissatisfaction is expressed with the utility's decision, of the customer's right to file a complaint with the regulatory authority thereon.

(6) Billing.

(A) Bills for gas service shall be rendered monthly, unless otherwise authorized or unless service is rendered for a period less than a month. Bills shall be rendered as promptly as possible following the reading of meters.

(B) The customer's bill must show all the following information. The information must be arranged and displayed in such a manner as to allow the customer to compute his bill with the applicable rate schedule. The applicable rate schedule must be mailed to the customer on request of the customer. A utility may exhaust its present stock of nonconforming bill forms before compliance is required by this section:

(i) if the meter is read by the utility, the date and reading of the meter at the beginning and end of the period for which rendered;

(ii) the number and kind of units billed;

(iii) the applicable rate schedule title or code;

(iv) the total base bill;

(v) the total of any adjustments to the base bill and the amount of adjustments per billing unit;

(vi) the date by which the customer must pay the bill to get prompt payment discount;

WEST TEXAS GAS UTILITY, LLC

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(vii) the total amount due before and after any discount for prompt payment within a designated period;

(viii) a distinct marking to identify an estimated bill.

(C) Where there is good reason for doing so, estimated bills may be submitted, provided that an actual meter reading is taken at least every six months. For the second consecutive month in which the meter reader is unable to gain access to the premises to read the meter on regular meter reading trips, or in months where meters are not read otherwise, the utility must provide the customer with a postcard and request that the customer read the meter and return the card to the utility if the meter is of a type that can be read by the customer without significant inconvenience or special tools or equipment. If such a postcard is not received by the utility in time for billing, the utility may estimate the meter reading and render the bill accordingly.

(D) Disputed bills.

(i) In the event of a dispute between the customer and the utility regarding the bill, the utility must forthwith make such investigation as is required by the particular case and report the results thereof to the customer. If the customer wishes to obtain the benefits of clause (ii) of this subparagraph, notification of the dispute must be given to the utility prior to the date the bill becomes delinquent. In the event the dispute is not resolved, the utility shall inform the customer of the complaint procedures of the appropriate regulatory authority.

(ii) Notwithstanding any other subsection of this section, the customer shall not be required to pay the disputed portion of the bill which exceeds the amount of that customer's average usage for the billing period at current rates until the earlier of the following: resolution of the dispute or the expiration of the 60-day period beginning on the day the disputed bill is issued. For purposes of this section only, the customer's average usage for the billing period shall be the average of the customer's usage for the same billing period during the preceding two years. Where no previous usage history exists, the average usage shall be estimated on the basis of usage levels of similar customers and under similar conditions.

(7) Meters.

(A) Meter requirements.

(i) Use of meter. All gas sold by a utility must be charged for by meter measurements, except where otherwise provided for by applicable law, regulation of the regulatory authority, or tariff.

(ii) Installation by utility. Unless otherwise authorized by the regulatory authority, each utility must provide and install and will continue to own and maintain all meters necessary for measurement of gas delivered to its customers.

WEST TEXAS GAS UTILITY, LLC

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(iii) Standard type. No utility may furnish, set up, or put in use any meter which is not reliable and of a standard type which meets generally accepted industry standards; provided, however, special meters not necessarily conforming to such standard types may be used for investigation, testing, or experimental purposes.

(B) Meter records. Each utility must keep the following records:

(i) Meter equipment records. Each utility must keep a record of all its meters, showing the customer's address and date of the last test.

(ii) Records of meter tests. All meter tests must be properly referenced to the meter record provided for therein. The record of each test made on request of a customer must show the identifying number and constants of the meter, the standard meter and other measuring devices used, the date and kind of test made, by whom made, the error (or percentage of accuracy) at each load tested, and sufficient data to permit verification of all calculations.

(iii) Meter readings--meter unit location. In general, each meter must indicate clearly the units of service for which charge is made to the customer.

(iv) Meter tests on request of customer.

(I) Each utility must, upon request of a customer, make a test of the accuracy of the meter serving that customer. The utility must inform the customer of the time and place of the test and permit the customer or his authorized representative to be present if the customer so desires. If no such test has been performed within the previous four years for the same customer at the same location, the test is to be performed without charge. If such a test has been performed for the same customer at the same location within the previous four years, the utility is entitled to charge a fee for the test not to exceed \$15 or such other fee for the testing of meters as may be set forth in the utility's tariff properly on file with the regulatory authority. The customer must be properly informed of the result of any test on a meter that serves him.

(II) Notwithstanding subclause (I) of this clause, if the meter is found to be more than nominally defective, to either the customer's or the utility's disadvantage, any fee charged for a meter test must be refunded to the customer. More than nominally defective means a deviation of more than 2.0% from accurate registration.

(v) Bill adjustments due to meter error.

(I) If any meter test reveals a meter to be more than nominally defective, the utility must correct previous readings consistent with the inaccuracy found in the meter for the period of either:

(-a-) the last six months; or

WEST TEXAS GAS UTILITY, LLC**Page 13 of 13****Effective: _____**

(-b-) the last test of the meter, whichever is shorter. Any resulting underbillings or overbillings are to be corrected in subsequent bills, unless service is terminated, in which event a monetary adjustment is to be made. This requirement for a correction may be foregone by the utility if the error is to the utility's disadvantage.

(II) If a meter is found not to register for any period of time, the utility may make a charge for units used but not metered for a period not to exceed three months previous to the time the meter is found not to be registering. The determination of amounts used but not metered is to be based on consumption during other like periods by the same customer at the same location, when available, and on consumption under similar conditions at the same location or of other similarly situated customers, when not available.

(8) New construction.

(A) Standards of construction. Each utility is to construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with the provisions of such codes and standards as are generally accepted by the industry, as modified by rule or regulation of the regulatory authority or otherwise

by law, and in such manner to best accommodate the public and to prevent interference with service furnished by other public utilities insofar as practical.

(B) Line extension and construction charges. Every utility must file its extension policy. The policy must be consistent, nondiscriminatory, and is subject to the approval of the regulatory authority. No contribution in aid of construction may be required of any customer except as provided for in extension policy.

(C) Response to request for service. Every gas utility must serve each qualified applicant for service within its service area as rapidly as practical. As a general policy, those applications not involving line extensions or new facilities should be filled within seven working days. Those applications for individual residential service requiring line extensions should be filled within 90 days unless unavailability of materials or other causes beyond the control of the utility result in unavoidable delays. In the event that residential service is delayed in excess of 90 days after an applicant has met credit requirements and made satisfactory arrangements for payment of any required construction charges, a report must be made to the regulatory authority listing the name of the applicant, location, and cause for delay. Unless such delays are due to causes which are reasonably beyond the control of the utility, a delay in excess of 90 days may be found to constitute a refusal to serve.

WEST TEXAS GAS UTILITY, LLC

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Effective: _____

RATE SCHE

RCE-INC

RATE CASE EXPENSE SURCHARGE – INCORPORATED

APPLICABILITY

All jurisdictional customers in the incorporated areas or cities in West Texas Gas Utility, LLC’s (“WTGU”) Texas Service Area.

RCE RATE

Pursuant to City ordinances or an order of the Railroad Commission of Texas in Case No. OS-24-00017816, WTGU is authorized to recover a total not to exceed \$___ in rate case expenses from Case No. OS-24-00017816 jurisdictional customers by a surcharge applicable to all jurisdictional customers in incorporated and unincorporated areas at the rate of \$0.___/Mcf for a period of approximately ___ months commencing _____.

COMPLIANCE

WTGU shall file an Annual Compliance Report with the Cities identified above annually, due on or before the ___ of each _____ commencing in _____. The report shall detail the monthly collections for the rate case expense surcharge and show the outstanding balance. The Compliance Report shall be addressed to the City Manager.

RESIDENTIAL SERVICE RATE – INCORPORATED

APPLICABILITY

Applicable to a residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes in an incorporated area or city served by West Texas Gas Utility, LLC. (“WTGU”). A residential consumer includes an individually-metered residential unit or dwelling and builders prior to sale or re-sale of a property for domestic purposes. This rate is only available to full requirements customers of WTGU.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Residential consumers per meter billing cycle or for any part of a billing cycle for which gas service is available at the same location.

Customer Charge \$29.50
All Consumption @ \$7.68 per Mcf

The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

OTHER FEES

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule Gas Cost Adjustment-INC.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE- INC.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee- INC.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEE- INC.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS- INC.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

WEST TEXAS GAS UTILITY, LLC

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TAX-INC

TAX ADJUSTMENT – INCORPORATED

REVENUE RELATED TAX ADJUSTMENT

Each monthly bill for a jurisdictional customer, as adjusted, shall also be adjusted by an amount equivalent to the various revenue related taxes, franchise fees, rentals, or other fees and charges imposed by regulatory or governmental authorities. This includes, but not limited to, Gross Receipts Taxes, Municipal Taxes, Fees, or any other governmental imposition, rental fee or charge levied that is based on any portion of revenues billed by West Texas Gas Utility, LLC.

WEST TEXAS GAS UTILITY, LLC

Page 1 of 2

Effective: _____

RATE SCHE
WINTER STORM RIDER

WINTER STORM URI SURCHARGE

APPLICABILITY

All Jurisdictional customers in the incorporated areas or cities in West Texas Gas Utility, LLC's ("WTGU") Texas Service Area.

PURPOSE

The purpose of the Winter Storm Uri Surcharge is to authorize WTGU to recover the reasonable, necessary, and prudent extraordinary gas costs incurred by WTGU as a result of Winter Storm Uri. The rate schedule is authorized by the Railroad Commission of Texas's ("Commission") Final Order in Case No. OS-24-00017816 and by cities that approved the corresponding request WTGU made with incorporated regulatory authorities, which approved a Winter Storm Uri Regulatory Asset and the recovery of the costs contained in the regulatory asset through a monthly surcharge. WTGU is authorized and directed to assess the Winter Storm Uri Surcharge rate as set forth in the section below.

SURCHARGE RATE

All Mcf during each billing period: \$0.41 per Mcf.

This rate will be in effect until all approved and expended Winter Storm Uri costs, up to \$3,502,862.41 ("Regulatory Asset Amount"), are recovered under the applicable rate schedules. Any excess recovery of the Regulatory Asset Amount shall be calculated and refunded to customers through a final true-up under this rate schedule.

OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

CONDITIONS

1. Subject to all applicable laws and orders, and WTGU's rules and regulations on file with the regulatory authority.
2. Uncollectible amounts, actually written off, associated with this surcharge shall be added back to the balance to be recovered via this surcharge.

WEST TEXAS GAS UTILITY, LLC

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RATE SCHE
WINTER STORM RIDER

3. Any amounts that were included in the Regulatory Asset Amount that are refunded to WTGU subsequent to the Final Order in Case No. OS-24-00017816 shall be subtracted from the balance and shall not be recovered via this surcharge.

WINTER STORM URI SURCHARGE RECOVERY COMPLIANCE REPORT

WTGU shall file a reconciliation report annually on or before March 31, commencing in 2026 and ceasing after a reconciliation report is filed at the end of the month following the month in which the Regulatory Asset Amount is fully recovered via the final reconciliation true-up (if applicable). WTGU shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing Case No. OS-24-00017816, Winter Storm Uri Surcharge Recovery Report. The report shall include:

- The volumes used by month by customer class during the applicable period;
- The amount of surcharge recovered, by month;
- The outstanding balance, by month;
- The associated uncollectibles, by month; and
- Any credits for amounts WTGU received that would offset the Regulatory Asset Amount

Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Compliance Filing
Director of Oversight and Safety Division
Gas Services Dept.
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

WEST TEXAS GAS UTILITY, LLC
 Test Period Ending December 31, 2023

SOI Exhibit B
 Page 1 of 1

BASE RATE REVENUE COMPARISON AT CURRENT, COST-BASED, AND PROPOSED RATES

Description	Reference	Current Base Rates			Proposed Base Rates	
		Unadjusted	Weather Adjustment	Adjusted	Proposed	% Increase
<u>Domestic Customers</u>						
Number of Domestic Customers	Schedule K	17,924		17,924	17,924	
Months per year		12		12	12	
Annual No. of Bills		215,084		215,084	215,084	
Domestic Customer Charge		\$ 23.42		\$ 23.42	\$ 29.50	26.0%
Monthly Customer Charge Revenues		5,037,267		5,037,267	6,344,978	
Domestic Volumes -- Mcfs	Schedule K	1,007,056	56,179	1,063,235	1,063,235	
Domestic Consumption Charge		\$ 4.84		\$ 4.84	\$ 7.68	58.7%
Consumption Charge Revenues		4,874,153		5,146,057	8,165,644	
Total Domestic Revenues		9,911,420		10,183,324	14,510,622	42.5%
<u>Non-Domestic Customers</u>						
Number of Non-Domestic Customers	Schedule K	2,484		2,484	2,484	
Months per year		12		12	12	
Annual No. of Bills		29,805		29,805	29,805	
Non-Domestic Customer Charge		\$ 43.57		\$ 43.57	\$ 79.00	81.3%
Monthly Customer Charge Revenues		1,298,604		1,298,604	2,354,595	
Non-Domestic Volumes -- Mcfs	Schedule K	601,671	32,693	634,364	634,364	
Non-Domestic Consumption Charge		\$ 2.69		\$ 2.69	\$ 4.89	81.8%
Consumption Charge Revenues		1,618,495		1,706,440	3,102,041	
Total Non-Domestic Revenues		2,917,099		3,005,044	5,456,636	81.6%
TOTAL JURISDICTIONAL REVENUES		12,828,519		13,188,368	19,967,258	51.4%

SOI EXHIBIT C
Page 1 of 1

Average Monthly Bill Impact

<u>Customer Class (Zone)</u>	<u>Current Average Monthly Bill Including Gas Cost (a)(b)</u>	<u>Proposed Average Monthly Bill Including Gas Cost (b)</u>	<u>Proposed Monthly Dollar Change</u>	<u>Proposed Monthly Percentage Change</u>
Domestic				
North	\$ 73.96	\$ 96.83	\$ 22.87	30.9%
West	\$ 60.83	\$ 80.67	\$ 19.84	32.6%
South	\$ 42.50	\$ 55.33	\$ 12.83	30.2%
Non-Domestic				
North	\$ 164.10	\$ 240.97	\$ 76.86	46.8%
West	\$ 179.22	\$ 268.22	\$ 89.01	49.7%
South	\$ 184.46	\$ 272.60	\$ 88.14	47.8%

(a) Current rates include WTGU's pending requested Gas Reliability Infrastructure Program charge.

(b) The cost of gas included in current and proposed monthly bills is the average by zone during the 2023 test year.

CASE NO. 00017816

**STATEMENT OF INTENT OF
WEST TEXAS GAS UTILITY, LLC TO
INCREASE GAS UTILITY RATES
WITHIN THE UNINCORPORATED
AREAS OF TEXAS**

§
§
§
§
§

**BEFORE THE
RAILROAD COMMISSION
OF TEXAS**

DIRECT TESTIMONY

OF

JACK J. KING

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

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EXHIBIT JJK-3 WTGU Purchase Agreement with WTGGM (CONFIDENTIAL)

EXHIBIT JJK-4 Calculation of Winter Storm Uri Surcharge

EXHIBIT JJK-5 Winter Storm Cost Recovery Riders

1 **DIRECT TESTIMONY OF JACK J. KING**

2 **I. INTRODUCTION AND QUALIFICATIONS**

3 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

4 A. My name is Jack J. (JJ) King. My business address is 303 Veterans Airpark Lane,
5 Suite 5000, Midland, Texas 79705.

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

7 A. I am employed by West Texas Gas Utility, LLC (“WTGU” or the “Company”) as
8 the Vice President of Gas Marketing. (WTGU, formerly known as West Texas
9 Gas, Inc. (“WTG-Inc.”)), changed entity names through a merger in September
10 2021.)

11 **Q. WHAT ARE YOUR DUTIES AS THE VICE PRESIDENT OF GAS**
12 **MARKETING?**

13 A. I am one of the corporate officers responsible for the utility pipeline operations of
14 WTGU and its subsidiaries with operations in Texas and Oklahoma, handling
15 marketing, business development, contract negotiations, contract administration,
16 financial performance, and relationships with cities served by WTGU.

17 **Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL**
18 **EXPERIENCE.**

19 A. I received a bachelor’s degree in Business Administration from Abilene Christian
20 University in 1994. From 1994 to 1996, I was the Sales Coordinator for
21 Compressor Systems, Inc. I joined WTG-Inc. in May 1996 as the Gas Contracts
22 Administrator, and I was promoted to Gas Marketing Manager in 2000. In February
23 2016, I was promoted and elected to become an officer of WTG-Inc. with the title
24 Vice President, Gas Marketing. Effective August 31, 2021, pursuant to a merger,

1 all of WTG-Inc.'s assets were conveyed to a newly formed entity, WTGU, by the
2 owner of WTG-Inc., the James L. Davis Estate (the "Merger").
3 Contemporaneously with the Merger, I was appointed as WTGU's Vice President,
4 Gas Marketing (i.e., the same officer position that I held with WTG-Inc. prior to
5 the Merger).

6 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY**
7 **COMMISSIONS?**

8 A. Yes. I testified before the Railroad Commission of Texas ("Commission") in Gas
9 Utilities Docket ("GUD") No. 9488 Consolidated and other cases before the
10 Commission, including the Company's prior rate cases, GUD No. 10235 in 2013
11 and Docket No. OS-20-00004347, in 2020. I have also appeared before the
12 Oklahoma Corporation Commission and various Texas municipalities in rate and
13 other regulatory proceedings.

14 **Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR**
15 **DIRECT SUPERVISION?**

16 A. Yes, it was.

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

19 A. Yes, I am sponsoring the exhibits listed in the table of contents.

20 **II. PURPOSE OF TESTIMONY**

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

23 A. The purpose of my testimony is to:

- 1 • provide an overview of WTGU's service territory, operations and customer
2 base;
- 3 • explain the reasons WTGU is filing a rate case at this time;
- 4 • support the prudence of the Company's capital investment through
5 December 31, 2023;
- 6 • address employee compensation and benefits issues along with other
7 expense items;
- 8 • explain WTGU's affiliate transactions and affiliate entities;
- 9 • address the proposed tariffs the Company is requesting, including the Gas
10 Cost Adjustment ("GCA") clause;
- 11 • describe WTGU's gas supply protocol and the advantages of combining
12 WTGU's gas supply efforts with affiliated entities; and
- 13 • support recovery of the Company's extraordinary gas costs related to Winter
14 Storm Uri.

15 **Q. ARE YOU SPONSORING ANY SCHEDULES?**

16 A. I am co-sponsoring the following schedules and my testimony supports the
17 reasonableness and necessity of the costs reflected in all of these schedules:

- 18 B-1 Operations and Maintenance Expenses
- 19 B-2 Administrative and General Expenses
- 20 H-1 Payroll Summary
- 21 H-2 Payroll Analysis
- 22 H-3 Bad Debts
- 23 H-4 Advertising Expenses
- 24 H-5 Donation and Contributions
- 25 H-6 Lobbying Expenses
- 26 H-7 Penalties and Fine
- 27 H-8 Outside Services Charged to A&G Accounts

- 1 H-9 Legal Expense Detail
- 2 H-10 Lost and Unaccounted for Gas
- 3 I-1 Organizational Chart
- 4 I-2 Charges by Affiliates to WTGU
- 5 I-3 Charges by Affiliates to Others

6 **Q. PLEASE IDENTIFY THE COMPANY'S OTHER WITNESSES WHO ARE**
7 **TESTIFYING IN SUPPORT OF THE COMPANY'S APPLICATION.**

8 A. In addition to my direct testimony, the following witnesses are testifying on
9 WTGU's behalf:

- 10 • Amanda Edgmon, Treasurer/Secretary also serving as WTGU Regulatory
11 Accountant, addresses the Company's books and records; attests to the financial
12 information contained in the Company's schedules; sponsors the Company's Gas
13 Reliability Infrastructure Program ("GRIP") filings; discusses the proposed change
14 to the factor to be used in future GRIP filings to determine the amount of capital
15 investment that should be allocated to or recovered from Jurisdictional Customers
16 for investment that benefits both Jurisdictional and Non-Jurisdictional Customers;
17 presents the calculation of the regulatory asset amount related to Winter Storm Uri;
18 and explains the corporate cost allocation method and services from some
19 affiliates.
- 20 • Matthew Smith, Associate Vice President of Operations, provides an overview of
21 field operations and expenses and supports the Company's rationale for its request
22 to modify the factor used to determine what portion of the Company's capital
23 investment will be recovered from Jurisdictional Customers for investment that
24 benefits both Jurisdictional and Non-Jurisdictional Customers.
- 25 • Dane A. Watson, with Alliance Consulting Group, sponsors the depreciation study
26 that he performed that produces the depreciation rates used to determine the
27 Company's depreciation expense.
- 28 • Dr. Bruce H. Fairchild, Principal with Financial Concepts and Applications, Inc.,
29 sponsors the Company's cost of service schedules, requested capital structure and
30 return on equity, overall rate of return, billing determinants, income tax expense
31 and other tax issues, cost allocation and rate design; and presents the Company's
32 proposed method for direct assignment of costs attributable to Jurisdictional
33 Customers and Non-Jurisdictional Customers.

III. OVERVIEW OF WTGU**Q. PLEASE DESCRIBE WTGU.**

A. WTGU is a Texas limited liability company as of September 1, 2021, headquartered in Midland, Texas. WTGU is not publicly traded on any stock exchange. WTGU is a natural gas utility in the States of Texas and Oklahoma that owns and operates gas distribution, gathering, and transmission pipeline systems. WTGU has affiliate entities in six states involved in natural gas marketing, intrastate and interstate gas transmission facilities, oil and gas exploration and production, gas gathering and processing facilities, and refined products distribution. WTGU's gas distribution facilities in Texas are located in seventy-three Texas counties and currently serve more than 23,500 domestic and non-domestic jurisdictional, and irrigation and agricultural non-jurisdictional customers. A Texas System Map is attached as Exhibit JJK-1.

Q. PLEASE EXPLAIN THE NATURE AND EXTENT OF WTGU'S UTILITY OPERATIONS IN TEXAS.

A. WTGU's utility operations began in 1976 with the acquisition of three rural natural gas systems primarily serving a few hundred irrigation and residential customers along a Northern Natural Gas transmission mainline running from the Permian Basin to the northern Texas Panhandle. WTGU has grown its local distribution company ("LDC") operations through numerous acquisitions and pipeline construction projects. Today, WTGU operates nearly 6,000 miles of distribution mains serving approximately 29,000 residential, commercial, irrigation and agricultural customers in Texas and Oklahoma.

1 Q. **WHERE IS WTGU'S PRINCIPAL OFFICE LOCATED?**

2 A. WTGU's principal office is located at 303 Veterans Airpark Lane, Suite 5000,
3 Midland, Texas. All corporate, legal, and accounting records of WTGU are
4 maintained at this principal office or located in nearby storage facilities. WTGU
5 also maintains regional field operations offices in Fort Stockton, Lubbock,
6 Junction, Canadian, Amarillo, Dalhart, and Lytle, Texas along with an office in
7 Guymon, Oklahoma. WTGU also has several small field offices serving WTGU's
8 Texas service area.

9 Q. **DOES WTGU OWN ANY TRANSMISSION LINES IN TEXAS?**

10 A. Yes. WTGU operates 752 miles of transmission pipeline in Texas that are used to
11 supply downstream WTGU distribution facilities and a few end-use or resale
12 customers. WTGU's affiliates WTG Gas Transmission Company, LLC
13 ("WTGGT") and Western Gas Interstate Company, LLC ("WGI"), are regulated
14 by the Commission or the Federal Energy Regulatory Commission ("FERC"), and
15 operate 710 miles and 67 miles, respectively, of transmission pipelines in Texas.

16 Q. **ARE WTGU'S TRANSMISSION PIPELINES THAT ARE OPERATED BY**
17 **AFFILIATES SHOWN ON THE TEXAS SYSTEM MAP?**

18 A. Yes. WTGGT and WGI intrastate and interstate transmission pipeline systems are
19 shown on Exhibit JJK-1.

20 Q. **DOES WTGGT OR WGI TRANSPORT ANY GAS TO WTGU'S**
21 **DISTRIBUTION SYSTEMS?**

22 A. Yes, there are a few WTGU distribution systems that are served upstream by
23 WTGGT or WGI. In these instances, both WTGGT and WGI charge only their

1 FERC or Commission-approved tariff rates, which WTGU recognizes as an
2 allowed gas cost element and includes these transport charges in WTGU's monthly
3 GCA clause.

4 **Q. IS WTGU DIFFERENT FROM OTHER TEXAS GAS UTILITY**
5 **COMPANIES?**

6 A. Yes. WTGU is much smaller, and therefore quite different, from the larger natural
7 gas utility companies that operate in Texas.

- 8 • As was true in our last rate case, a significant portion of WTGU's load profile
9 continues to consist of non-jurisdictional agricultural markets. These
10 markets are largely composed of interruptible short-term service agreements
11 where customers pay no demand charges and have no minimum throughput
12 requirements.
- 13 • Due to the portion of non-jurisdictional customers WTGU serves, a recurring
14 regulatory issue is what portion of ongoing investment should be recovered
15 from jurisdictional customers regulated by the Commission and cities
16 WTGU serves. Currently, WTGU is authorized to recover from
17 jurisdictional customers a little more than one-third of its overall ongoing
18 capital investment, which understates the level of investment the Company
19 makes to serve jurisdictional customers. This rate treatment affects the
20 return the Company is able to earn on its investment.
- 21 • Even though WTGU serves areas of new development in the Amarillo,
22 Lubbock, and San Antonio areas, WTGU's jurisdictional customers are
23 generally located in small rural municipalities and rural environs. The
24 Company has nearly 6,000 miles of distribution pipelines situated in seventy-
25 three Texas counties. WTGU's average miles of pipeline per customer meter
26 and cost of service per customer are likely higher than a gas utility serving
27 large metropolitan areas, which are much more densely populated.
- 28 • Due to the Company's limited staff, WTGU's management and supervisory
29 personnel are responsible for a wide range of duties. Risk management,
30 legal, safety training, fleet management, engineering and drafting, rate
31 regulation, and other functions are shared by a limited number of staff
32 members, or outside consultants must be retained.

1 **Q. PLEASE ELABORATE ON THE DIFFERENCES BETWEEN WTGU’S**
 2 **OPERATIONS IN LARGELY RURAL AREAS WITH LOW CUSTOMER**
 3 **DENSITY COMPARED TO OTHER LDCS IN TEXAS.**

4 A. Based on 2023 data, WTGU serves an average of 6 customers per mile of pipeline,
 5 whereas the Texas LDC that is next closest in size to WTGU serves an average of
 6 39 customers per mile of pipeline. An average calculation for several LDCs
 7 throughout the state shows the average is 53 customers per mile of pipeline.¹

8 Similar differences exist for the number of service lines per mile of pipeline,
 9 as shown in the table below. WTGU averages just over 6 service lines per mile of
 10 pipeline, whereas the average for LDCs throughout the state is just over 53 service
 11 lines per mile.

	Total Miles of Main	Total Service Lines	Service Lines/Mile
West Texas Gas Utility	4,861	29,795	6
Atmos Energy - West Texas	8,763	339,797	39
SiEnergy	1,076	52,949	49
Atmos Energy - Mid-Tex	32,448	1,808,445	56
CenterPoint Energy	35,201	2,010,363	57
CoServ Gas	2,460	149,019	61
Texas Gas Service	11,121	712,587	64
Average Service Lines Per Mile	95,930	5,102,955	53

¹ 2023 PHMSA Annual Gas Distribution Report. The averages were calculated for WTGU, Atmos Energy (Mid-Tex and West Texas Divisions), SiEnergy, CenterPoint Energy, CoServ Gas and Texas Gas Service Company.

1 **Q. WHO REGULATES THE RATES, OPERATIONS AND ACCOUNTING**
2 **PRACTICES OF WTGU?**

3 A. WTGU's gas distribution rates are regulated by the cities in which it provides
4 service and the Commission. Pipeline safety regulations issued and enforced by
5 the Commission and the US Department of Transportation apply to WTGU's
6 pipeline operations. The Commission has adopted FERC's Uniform System of
7 Accounts ("USOA") for accounting reporting purposes and WTGU complies with
8 this reporting system, which Company witness Amanda Edgmon addresses in her
9 direct testimony.

10 **Q. DOES WTGU USE GENERALLY ACCEPTED ACCOUNTING**
11 **PRINCIPLES ("GAAP") IN THE ORDINARY COURSE OF BUSINESS?**

12 A. Yes. Due to bank loan covenants, WTGU and its affiliates are required to maintain
13 their books and records in accordance with GAAP. Therefore, WTGU and its
14 affiliates utilize a common accounting software system, chart of accounts, and
15 financial reporting software to satisfy the GAAP requirement. WTGU utilizes a
16 cross reference to its chart of accounts for FERC accounting and reporting
17 purposes. WTGU files all regulatory reports and annual filings on a FERC
18 accounting basis. The schedules contained in this rate filing all use the FERC
19 USOA.

20 **IV. WTGU CUSTOMER BASE**

21 **Q. PLEASE DESCRIBE WTGU'S JURISDICTIONAL CUSTOMER**
22 **CLASSES.**

23 A. WTGU has two jurisdictional customer classes: domestic and non-domestic
24 customers as follows:

Domestic Customers	Non-Domestic Customers
Residential	Commercial Public Authority Non-Profit

1 **Q. HOW MANY DOMESTIC AND NON-DOMESTIC CUSTOMERS ARE**
 2 **SERVED BY WTGU IN TEXAS?**

3 A. As of December 31, 2023, WTGU has a total of 20,407 jurisdictional Texas
 4 customers consisting of 17,923 domestic and 2,485 non-domestic customers.
 5 WTGU’s number of municipal and environs jurisdictional customers in Texas is as
 6 follows:

	<u>Domestic</u>	<u>Non-Domestic</u>	<u>Total</u>
7 Environs	5,747	475	6,222
8 <u>Municipal</u>	<u>12,176</u>	<u>2,010</u>	<u>14,186</u>
9 Total	17,923	2,485	20,407

11 **Q. HAS THE NUMBER OF JURISDICTIONAL CUSTOMERS GROWN**
 12 **SINCE THE LAST RATE CASE?**

13 A. Yes. The number of customers served by WTGU has slowly grown since the 2020
 14 rate case. The following chart shows WTGU’s customer count at December 31 for
 15 each year from 2019 through 2023.

	<u>Domestic</u>	<u>Non-Domestic</u>	<u>Total</u>
16 2019	15,725	2,228	17,953
17 2020	15,937	2,233	18,170
18 2021	16,597	2,371	18,968
19 2022	17,048	2,523	19,571
20 2023	17,923	2,485	20,407

1 **Q. WHAT FACTORS HAVE CONTRIBUTED TO WTGU'S INCREASE IN**
2 **CUSTOMERS WITHIN TEXAS?**

3 A. As was true in the last rate case, growth in the environs areas south and southwest
4 of Amarillo and north of the City of Canyon, and continued extensions into new
5 subdivisions in the Lubbock and San Antonio areas, are driving growth. At the
6 same time, several areas served by WTGU in the smaller rural municipalities and
7 their environs have experienced negative growth.

8 **Q. DOES WTGU EXPECT CUSTOMER GROWTH TO CONTINUE?**

9 A. Yes. The population growth that is occurring in and around the cities of Amarillo,
10 Canyon, Lubbock, San Antonio and south of Austin is expected to continue, which
11 will create slow yet steady growth for WTGU. In addition, the Company is open
12 to acquiring small utility systems that fit in or around our current geographical
13 footprint and align well with WTGU's current operations.

14 **Q. WHAT IS THE AVERAGE MONTHLY CONSUMPTION FOR WTGU'S**
15 **TEXAS JURISDICTIONAL CUSTOMERS?**

16 A. During the test year, the average monthly unadjusted consumption for domestic
17 customers was 4.7 Mcf and 20.18 Mcf for non-domestic customers.

18 **V. PURPOSE OF RATE CASE FILING**

19 **Q. WHY IS WTGU FILING A RATE CASE AT THIS TIME?**

20 A. There are a few primary reasons WTGU is filing a rate case right now. First, the
21 Company's existing rates are not sufficient to allow it a reasonable opportunity to
22 earn a reasonable return on its investment. This is a result of a few factors,
23 including that the costs of doing business have increased in the last five years,
24 substantial ongoing Distribution Integrity Management Program ("DIMP") work

1 necessitating supervision and capital investment, and prior rate decisions that limit
2 the cost of service that can be recovered from jurisdictional customers.

3 Relatedly, another reason WTGU is filing a rate case is to better align the
4 investment it makes and cost recovery from customers who benefit from the
5 investment. Specifically, in the Company’s 2013 and 2020 rate cases, the
6 Commission approved a “jurisdictional allocation factor” that caps the percentage
7 of capital investment costs the Company can recover from jurisdictional customers
8 in the rate cases as well as in GRIP filings. In the last rate case, the approved
9 percentage was 36.75% and the parties agreed the jurisdictional allocation factor
10 would be analyzed further in the Company’s next rate case. These issues adversely
11 impact the Company’s ability to earn its allowed rate of return for the service
12 WTGU provides to jurisdictional customers.

13 Finally, the Company is seeking recovery of the extraordinary gas costs it
14 incurred to maintain and provide service to customers during Winter Storm Uri in
15 February 2021. WTGU has not recovered any of those costs and did not participate
16 in the securitization proceeding the Commission oversaw in 2021 and 2022.

17 **Q. DOES WTGU TAKE STEPS TO CONTROL ITS OPERATING COSTS?**

18 A. Yes, however WTGU’s single largest cost of service item is personnel costs.
19 WTGU would not be able to provide customers with the safe and reliable service it
20 provides without a sufficient number of employees who must be compensated in a
21 reasonable way. The Company’s number of employees, employee pay rates, and
22 related personnel benefits compare favorably to other Texas distribution utilities.
23 As a privately held utility, WTGU is also very cost-conscious. WTGU also avoids

1 some costs incurred by publicly traded utilities, such as Securities and Exchange
2 Commission related compliance and reporting expenses as well as stockholder
3 relations expenses.

4 **Q. PLEASE DESCRIBE THE STATEMENT OF INTENT FILINGS MADE BY**
5 **WTGU.**

6 A. WTGU filed its Statements of Intent with the Commission and its thirty-six (36)
7 municipalities on July 16, 2024, using a test year ending December 31, 2023.

8 **Q. ARE THERE ANY CITIES THAT HAVE SURRENDERED THEIR**
9 **ORIGINAL JURISDICTION TO THE COMMISSION?**

10 A. No.

11 **Q. PLEASE DESCRIBE WTGU’S PROPOSED RATE INCREASE.**

12 A. WTGU proposes an approximately \$6.8 million revenue increase for its
13 jurisdictional customers with the intent of continuing to use generally applicable
14 statewide rates in Texas, which includes incorporated and environs areas in which
15 WTGU operates. The use of statewide rates was initially approved in WTGU case,
16 GUD No. 9488 Consolidated, and the Commission-approved statewide rates in
17 WTGU’s last rate proceedings in GUD No. 10235 and Docket No. OS-20-
18 00004347.² The continuation of a uniform statewide rate structure for WTGU
19 customers, along with continued recognition of the differences in the cost of gas in

² *Statement of Intent Filed by West Texas Gas, Inc., to Increase Special Rates in the Unincorporated Towns and Rural Areas, Environs, and Appeals from the Decisions of the Cities of Balmorhea, Claude, Darrouzett, Eden, Farwell, Follett, Groom, Higgins, Junction, Menard, Miami, Mobeetie, Shamrock, Stratford, Texhoma, Wheeler, Paint Rock, Cactus, Canadian, Kermit, Natalia, Somerset, Sonora, and Texline*, GUD No. 9488, Final Order at Finding of Fact No. 19 and Conclusion of Law No. 3 (Nov. 23, 2004); *Statement of Intent of West Texas Gas, Inc. to Increase Gas Distribution Rates in the Unincorporated Areas of Texas*, GUD No. 10235, Final Order (Jun. 13, 2013); *Statement of Intent of West Texas Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of Texas*, Docket No. OS-20-00004347 consol., Final Order (Feb. 9, 2021).

1 the various regions that WTGU serves, will help ensure that all customers pay rates
 2 that reflect WTGU’s actual cost of service.

3 **Q. WHAT IS THE IMPACT OF THE PROPOSED RATES ON DOMESTIC**
 4 **AND NON-DOMESTIC CUSTOMERS IN TEXAS?**

5 A. Inclusive of a \$3.40 per Mcf average cost of gas during the test year, a typical
 6 domestic customer using 6 Mcf in a billing period will experience an increase of
 7 \$23.12, or 31.7%. A domestic customer is one whose natural gas service is
 8 individually metered and typically refers to residential service. Using the same
 9 average cost of gas, a non-domestic customer using 30 Mcf in a billing cycle will
 10 experience a \$101.43, or 44.8%, increase. Non-domestic customers include
 11 commercial, industrial or non-profit customers.

12 **Q. WILL THE RATES THE COMPANY IS REQUESTING ALLOW IT TO**
 13 **RECOVER THE FULL INCREASE IN ITS COST OF SERVICE AS**
 14 **SHOWN IN THE SCHEDULES PREPARED BY DR. FAIRCHILD?**

15 A. No. Fully cost-based rates as calculated by Dr. Fairchild would create a very large
 16 rate increase for customers compared to current rates:

<u>Description</u>	<u>Current Rates³</u>	<u>Cost-Based Rates</u>	<u>Percentage Change</u>
<u>Domestic Customers</u>			
Customer Charge	\$ 23.42	\$ 71.63	205.8%
Commodity Charge (Mcf)	\$ 4.84	\$ 4.67	-3.6%
<u>Non-Domestic Customers</u>			
Customer Charge	\$ 43.57	\$ 82.89	90.2%
Commodity Charge (Mcf)	\$ 2.69	\$ 9.61	257.4%

³ Includes customer charge amounts for the Company’s GRIP filing made on May 17, 2024.

1 To moderate customer rate impacts, the Company is requesting rates that are less
 2 than necessary to recover the full cost of service as shown below. Even though the
 3 Company’s increase in the cost of service supports the requested rate increase, the
 4 Company is aware that the requested rates represent a sizeable increase compared
 5 to current rates.

<u>Description</u>	<u>Current Rates</u>	<u>Requested Rates</u>	<u>Percentage Change</u>
<u>Domestic Customers</u>			
Customer Charge	\$ 23.42	\$ 29.50	26.0%
Commodity Charge (Mcf)	\$ 4.84	\$ 7.68	58.7%
<u>Non-Domestic Customers</u>			
Customer Charge	\$ 43.57	\$ 79.00	81.3%
Commodity Charge (Mcf)	\$ 2.69	\$ 4.89	81.8%

6 **VI. RATE BASE**

7 **Q. PLEASE DESCRIBE WTGU’S TEST YEAR PROPERTY AND PLANT**
 8 **THAT IS INCLUDED IN THE COMPANY’S RATE BASE AMOUNTS.**

9 A. WTGU’s requested rate base, the amount on which a utility is entitled to earn a fair
 10 rate of return, is shown on Schedule C, with underlying rate base data shown on
 11 Schedules C-1 through C-5. As shown on Schedule C, rate base consists of
 12 WTGU’s investment in property, plant and equipment, plus materials and supplies,
 13 less contributions in aid of construction provided by WTGU customers, and
 14 deferred income taxes. WTGU’s investment includes assets exclusively serving
 15 customers in Texas and an allocated portion of assets serving customers in the
 16 Texas and Oklahoma service areas.

1 **Q. PLEASE EXPLAIN WTGU'S ORIGINAL COST, ACCUMULATED**
2 **DEPRECIATION AND NET BOOK COST CALCULATIONS TO**
3 **DEVELOP THE COMPANY'S NET COST USED FOR PROPERTY,**
4 **PLANT AND EQUIPMENT.**

5 A. The original cost and accumulated depreciation of WTGU's property, plant, and
6 equipment are reflected on Lines 13 and 14 of Schedule C, with detail of this
7 property by FERC account being contained in Schedules C-1 and C-2, respectively.
8 Schedule C reflects the test year-end balances for WTGU and adjustments made by
9 Dr. Fairchild.

10 **Q. DO THE TEST YEAR RATE BASE AMOUNTS INCLUDE COSTS PAID**
11 **TO DEVELOPERS FOR ACCESS TO NEW DEVELOPMENTS IN**
12 **WTGU'S SERVICE TERRITORY?**

13 A. Yes. Increasingly, those types of costs have become a cost of doing business for
14 the Company. While not all developers charge the Company these one-time fees,
15 the fees for the ones who do charge typically range from \$200 to \$350 per lot
16 depending on the location and level of competition in the area. In our experience,
17 developers have also become fairly sophisticated in trying to create competition for
18 utility access to a new subdivision or development, including whether the
19 development will be served by a gas or an electric utility. The Company wants to
20 grow its customer base, which helps generate a larger number of customers to
21 spread the Company's costs over. Existing WTGU customers benefit from this
22 growth, and the Company wants to continue to make natural gas an option for
23 residences and local businesses. In addition, without gaining access to these new

1 developments, there is a risk the related homes and businesses would be built to use
2 all electric appliances and service, which is a higher-cost energy source than natural
3 gas.

4 **Q. HAS THE COMPANY MADE ANY ACQUISITIONS SINCE ITS LAST**
5 **RATE CASE IN 2020?**

6 A. Yes. WTGU acquired the City of Van Horn distribution system in May 2021.

7 **Q. PLEASE DESCRIBE THE CITY OF VAN HORN ACQUISITION.**

8 A. Effective May 1, 2021, WTGU acquired the City of Van Horn, Texas gas
9 distribution system. This gas distribution system is situated mainly in the
10 incorporated limits of the City of Van Horn and serves almost 745 jurisdictional
11 domestic and non-domestic customers. This system is composed of about 17.05
12 miles of steel mainline and more than 6.6 miles of poly mainline and service
13 laterals. The purchase price was less than the \$1 million threshold in GURA
14 § 102.051.

15 **Q. DESCRIBE THE PROPOSED TREATMENT OF WTGU'S DIMP**
16 **CAPITAL INVESTMENT.**

17 A. Capital costs related to WTGU's DIMP are included in Schedule C-5 and are
18 included as a part of WTGU's rate base. In addition, DIMP capital costs are
19 included in each of WTGU's GRIP filings made since Docket No. OS-20-
20 00004347, which Ms. Edgmon and Mr. Smith address in their testimonies. DIMP
21 capital costs are an example of the type of investment that benefits jurisdictional
22 customers, yet WTGU is not able to fully recover the amount of investment from
23 jurisdictional customers due to the jurisdictional allocator approved in the last rate

1 case. The same allocator is also applied to DIMP investment included in the
2 Company's GRIP filings. As Ms. Edgmon explains in her testimony, going
3 forward, the Company is requesting approval to recover all of the costs of
4 jurisdictional investment from jurisdictional customers and none of the costs of
5 non-jurisdictional investment from jurisdictional customers.

6 **Q. PLEASE DESCRIBE THE MATERIALS AND SUPPLIES AMOUNTS**
7 **SHOWN ON SCHEDULE C-3.**

8 A. WTGU maintains pipe and other inventories at some of its larger field offices,
9 including steel and poly pipe, regulators, meters, steel and poly fittings and valves,
10 risers, anodes, marker signage, replacement parts for valves, regulators, and meters.
11 WTGU has included \$1.85 million as shown on Schedule C-3 for materials and
12 supplies inventory. The calculations of the amount sought are sponsored by
13 Dr. Fairchild.

14 **Q. ARE ANY MATERIALS AND SUPPLIES COSTS RECOVERED**
15 **THROUGH WTGU'S GCA CLAUSE?**

16 A. No.

17 **Q. PLEASE DESCRIBE THE TREATMENT OF CUSTOMER DEPOSITS**
18 **SHOWN ON SCHEDULE C.**

19 A. The balance of Customer Deposits reflected on Schedule C is included as a
20 reduction of WTGU's rate base because WTGU pays interest on these customer
21 deposits at the interest rate stipulated by the Public Utility Commission of Texas
22 and adopted by the Railroad Commission.

1 **Q. PLEASE EXPLAIN WTGU'S TREATMENT OF CONTRIBUTIONS IN**
2 **AID OF CONSTRUCTION.**

3 A. Typically, WTGU requires customer contributions in aid of construction for
4 projects that do not qualify under WTGU's extension policy because it fails to meet
5 minimum investment criteria (e.g., rate of return or capital investment thresholds)
6 based on published tariff rates or standard non-jurisdictional rates. These
7 contributions are amortized over the life of the related capital investment and used
8 to offset depreciation expense on WTGU's books.

9 **Q. WHAT IS WTGU'S RATE BASE?**

10 A. The Company's rate base consists of invested capital that is used and useful in
11 providing utility service to customers. Rate base is also used to determine the return
12 portion of WTGU's cost of service, which is calculated by Dr. Fairchild.

13 **Q. HAS WTGU INCLUDED AN ALLOWANCE FOR CASH WORKING**
14 **CAPITAL AS A COMPONENT OF ITS RATE BASE?**

15 A. No. To reduce rate case expenses, WTGU has not performed a lead lag study, so
16 WTGU has not included any provision for cash working capital in the requested
17 rate base amount.

18 **Q. HAS THE COMPANY'S RATE BASE BEEN ADJUSTED FOR NON-**
19 **INVESTOR SUPPLIED CAPITAL?**

20 A. Yes. As reflected on Schedule C, WTGU's rate base has been adjusted for
21 Customer Deposits, Contributions in Aid of Construction, Accumulated Deferred
22 Income Taxes ("ADIT") and Excess ADIT. The calculation of the adjustments for
23 non-investor supplied capital is sponsored by Dr. Fairchild.

1 **Q. IS WTGU’S ENTIRE RATE BASE USED AND USEFUL FOR SERVING**
2 **ITS CUSTOMERS?**

3 A. Yes. Assets that are not used and useful have been removed from the rate base
4 calculations. In addition to transmission assets and those assets identified with
5 WTGU’s Oklahoma operations, amounts related to acquisition premiums, non-
6 utility assets, and out-of-service assets have also been removed from WTGU’s rate
7 base. Schedule A-3 and all of the C Schedules provide the details for these
8 adjustments to rate base.

9 **Q. IS THERE ANY PLANT, PROPERTY OR EQUIPMENT IN RATE BASE**
10 **THAT COULD BE CLASSIFIED AS PLANT HELD FOR FUTURE USE OR**
11 **CONSTRUCTION WORK IN PROGRESS?**

12 A. No. There is no plant held for future use or construction work in progress included
13 in WTGU’s rate base. Out-of-Service plant, which might be considered gas plant
14 for future use, has also been removed from rate base. All of WTGU’s property,
15 plant and equipment included in rate base is currently dedicated to serving WTGU
16 customers.

17 **VII. DEPRECIATION EXPENSE**

18 **Q. PLEASE DESCRIBE WTGU’S DEPRECIATION EXPENSE.**

19 A. Consistent with the Commission’s prior rulings in GUD No. 9488, and with the
20 filings and rulings in GUD No. 10235 and Docket No. OS-20-00004347, the
21 depreciation rates in this case are based upon a depreciation study. As it did in the
22 last rate case, the Company retained Mr. Dane Watson of Alliance Consulting
23 Services to conduct a depreciation study. His studies, conclusions, and
24 recommendations are included in this rate case.

1 **Q. AS A RESULT OF THE NEW DEPRECIATION STUDY, HOW MUCH IS**
2 **WTGU SEEKING TO RECOVER IN DEPRECIATION EXPENSE?**

3 A. WTGU is seeking to recover \$5.2 million in depreciation expense from its
4 jurisdictional customers as shown in Schedule D. Mr. Watson's testimony and
5 depreciation study provide additional information to support this request.

6 **VIII. RATE OF RETURN AND COST OF DEBT**

7 **Q. WHAT RATE OF RETURN WAS USED IN CALCULATING WTGU'S**
8 **REVENUE REQUIREMENT?**

9 A. As reflected in Schedule E, WTGU utilized a rate of return of 8.10% in calculating
10 its revenue requirement. Please see the direct testimony of Dr. Fairchild supporting
11 WTGU's proposed cost of capital and overall return.

12 **Q. WHAT IS WTGU'S REQUESTED COST OF DEBT?**

13 A. The weighted average cost of debt calculated on Schedule E is 1.05%. However,
14 the cost of long-term debt included in this filing is 3.06% and is supported by
15 Dr. Fairchild.

16 **Q. WHAT BANKING INSTITUTIONS HAVE LOANED MONEY TO WTGU?**

17 A. WTGU and its affiliates are parties to a credit facility provided by a syndicate of
18 national and international banks lead by Mizuho. WTGU and its affiliates are
19 jointly and severally liable for all outstanding amounts owed under this credit
20 facility.

21 **Q. DOES WTGU HAVE ANY OUTSTANDING DEBT?**

22 A. Yes. As of December 31, 2023, WTGU's outstanding debt is \$155,000,000 owed
23 to the syndicate group of banks led by Mizuho.

1 **IX. REVENUE AND EXPENSES**

2 **Q. PLEASE IDENTIFY ANY ADJUSTMENTS TO REVENUES.**

3 A. The only adjustments to test year revenues are to weather normalized volumes for
4 domestic and non-domestic customers as shown on Schedules A-2 and A-3. In
5 addition, the current revenues included in the cost of service schedules include
6 revenues related to the GRIP filing the Company made on May 17, 2024.
7 Dr. Fairchild sponsors these calculations in the schedules.

8 **Q. WERE THERE ANY ADJUSTMENTS FOR SALARY DECREASES OR**
9 **TERMINATIONS?**

10 A. No. There were no salary decreases or overall staff reductions during the test year.
11 The payroll costs WTGU seeks to recover in this case are shown on Schedules H-
12 1 and H-2 with adjustments summarized on Schedule A-3.

13 **Q. WHAT STEPS DOES THE COMPANY TAKE TO ENSURE THAT ITS**
14 **COMPENSATION FOR EMPLOYEES IS REASONABLE?**

15 A. The Company operates in a geographic region where there is competition for
16 experienced utility employees and other types of employees who are necessary to
17 support typical corporate and business functions. To provide adequate
18 compensation to attract and retain employees, the Company considers salary data
19 for our industry, including information available from the U.S. Bureau of Labor
20 Statistics. WTGU believes its salary scale is generally average, but below the level
21 of some larger companies with identical positions in our service area. In addition
22 to salary, employees are also eligible for bonuses.

1 **Q. COULD WTGU RETAIN OR REPLACE ITS CURRENT STAFF WITH**
2 **COMPARABLE EMPLOYEES WITHOUT THE COMPENSATION PAID**
3 **TO EMPLOYEES?**

4 A. No. The salary levels and bonuses awarded are necessary to retain and properly
5 compensate employees with a competitive salary package when compared to
6 similar positions with other companies in the Midland employment market.
7 Employee retention is an important factor in controlling labor costs. Retention of
8 long-term employees preserves institutional knowledge and experience, which
9 enhances pipeline safety and service reliability. In addition, to the extent WTGU
10 must hire new employees, the salaries it offers must be sufficient to compete with
11 other employers.

12 **Q. DOES WTGU FACE COMPETITION FROM OTHER EMPLOYERS IN**
13 **THE REGION THAT REQUIRE THE SAME TYPES OF EMPLOYEES AS**
14 **WTGU?**

15 A. Yes. In addition to other utilities in the area, WTGU employees also have the
16 experience and skill sets to work in non-regulated industries, especially dealing
17 with oil and gas issues. Those types of jobs are in high demand not only in the
18 immediate Midland area but also throughout the areas where WTGU provides
19 service. There are regularly instances in which our employees are approached by
20 other employers who are interested in hiring them away from WTGU. For these
21 reasons, WTGU must take steps to retain existing employees including offering
22 base pay and benefits that adequately compensate employees.

1 **Q. DOES WTGU OFFER EMPLOYEES BENEFITS?**

2 A. Yes. The Company provides traditional benefits such as health, dental and vision
3 insurance, as well as paid time off and a 401(k). Benefits costs are shown on
4 Schedule B-2.

5 **Q. PLEASE DESCRIBE THE ADVERTISING EXPENSES SHOWN ON**
6 **SCHEDULE H-4.**

7 A. The majority of the advertising expenses shown on Schedule H-4 are costs incurred
8 related to advertising in local area newspapers for employment ads. Costs also
9 include advertisements in home builder publications as well as with local chambers
10 of commerce.

11 **Q. IS WTGU SEEKING TO RECOVER COSTS OF DONATIONS AND**
12 **CONTRIBUTIONS MADE DURING THE TEST YEAR (SCHEDULE H-5)?**

13 A. No. The donations and contributions amounts shown on Schedule H-5 have been
14 removed from the Company's request in this case, which is also shown on
15 Schedule A-3.

16 **Q. IS WTGU REQUESTING RECOVERY OF PENALTIES AND FINES**
17 **IDENTIFIED ON SCHEDULE H-7?**

18 A. No, amounts for penalties or fines shown on Schedule H-7 have been removed from
19 the rate request, as shown on Schedule A-3.

20 **Q. WHAT IS WTGU'S POLICY REGARDING EMPLOYEE EXPENSES?**

21 A. As part of the last rate case, WTGU agreed to submit a policy to Commission Staff
22 that addresses employee expenses, which the Company did in March 2021. The
23 General Employee Expense and Reimbursement Policy is designed to facilitate

1 evaluation of employee expenses by the Commission and contains guidelines for
2 reimbursable expenses that might be incurred while an employee is traveling to
3 carry out his or her assigned duties or incurred while fulfilling a company
4 responsibility or company function. Reimbursable expenses must be supported
5 with an itemized receipt or invoice that indicates the goods or services provided
6 and the individuals that received those goods or services. Exceptions are made to
7 this guideline if the amount being reimbursed is considered immaterial, generally
8 \$25 or less. Acceptable entertainment is generally considered to be a meal with a
9 customer, vendor, business associate, or subordinate employee.

10 **Q. WHAT IS THE COMPANY’S TRAVEL POLICY?**

11 A. Because most of WTGU’s assets are situated in rural or remote areas of the state,
12 automobile travel is the predominate method of travel for WTGU management and
13 supervisory personnel. In addition, the General Employee Expense and
14 Reimbursement Policy notes that travel expenses must include documentation of
15 the purpose for the travel, a copy of the itinerary and identification of employees
16 traveling. Regarding lodging, the policy addresses the types of rooms that should
17 be booked and contains guidelines for reimbursable lodging costs.

18 **Q. IS THE COMPANY REQUESTING RECOVERY OF TEST YEAR MEAL,
19 LODGING AND ENTERTAINMENT EXPENSES?**

20 A. No. All meal, lodging and entertainment expenses have been removed. The
21 Company would have to engage in a time-intensive, manual review to exclude
22 entertainment expenses and only amounts above the Commission’s current meal

1 and lodging thresholds. To reduce issues in controversy, the Company has made
2 the decision to remove all meal, lodging and entertainment expenses.

3 **Q. PLEASE DESCRIBE SCHEDULE H-9.**

4 A. Schedule H-9 reflects legal fees paid to various attorneys during the test year.
5 Those charges identified as Other Legal Matters pertain to fees incurred in the
6 renegotiation and renewal of WTGU's credit facility with the Mizuho syndicate
7 group, as well as fees paid for bad account collection, miscellaneous regulatory
8 matters, and general corporate business.

9 **X. LOST AND UNACCOUNTED FOR GAS**

10 **Q. PLEASE DESCRIBE SCHEDULE H-10.**

11 A. Schedule H-10 reflects the lost and unaccounted for gas ("LUFG") volumes
12 experienced by WTGU for the twelve-month period ending December 31, 2023.
13 Any LUFG volumes from WTGU transmission systems have been eliminated in
14 this schedule to reflect only the actual LUFG on WTGU's Texas distribution
15 systems.

16 **XI. AFFILIATE TRANSACTIONS**

17 **Q. PLEASE DESCRIBE THE STATUTORY STANDARD GOVERNING THE**
18 **RECOVERY OF AFFILIATE EXPENSES.**

19 A. Section 104.055 of GURA establishes that affiliate expenses must be reasonable
20 and necessary and that the price charged to the gas utility not be higher than the
21 price charged by the affiliate to its other affiliates, or to a non-affiliated person for
22 the same items or class of items.

1 **Q. IN YOUR OPINION, DO WTGU'S AFFILIATE EXPENSES MEET THE**
2 **AFFILIATE STANDARD YOU JUST DESCRIBED?**

3 A. Yes.

4 **Q. ARE THE EXPENSE AMOUNTS WTGU PAID TO AFFILIATES DURING**
5 **THE TEST YEAR REASONABLE AND NECESSARY?**

6 A. Yes. WTGU does not pay any affiliate charges that exceed normal charges from
7 arms-length third-party transactions.

8 **Q. ARE THE PRICES WTGU PAID TO AFFILIATES HIGHER THAN**
9 **PRICES CHARGED BY THE SUPPLYING AFFILIATE TO OTHER**
10 **AFFILIATES OR NON-AFFILIATES FOR THE SAME ITEM OR CLASS**
11 **OF ITEM?**

12 A. No. The amounts paid by WTGU to affiliates are equal to, or less than, similar
13 charges paid by non-affiliate entities.

14 **Q. ARE AFFILIATE COSTS INCLUDED IN WTGU'S OPERATING**
15 **EXPENSES?**

16 A. Yes, affiliate expenses are as shown on Schedule I-2.

17 **Q. ARE THE AFFILIATE COSTS ON SCHEDULE I-2 THE SAME TYPES OF**
18 **AFFILIATE COSTS THAT WERE INCLUDED IN WTGU'S LAST RATE**
19 **CASE?**

20 A. Yes, and the Commission's final order in that case reflects the parties' agreement
21 that the affiliate costs in the last rate case met the affiliate cost recovery standard.

1 **Q. PLEASE DESCRIBE SCHEDULE I-1 AND THE NATURE OF WTGU, ITS**
2 **AFFILIATES, PARENT, AND SUBSIDIARIES.**

3 A. Schedule I-1 is an organization chart as of December 31, 2023, depicting the direct
4 parent of WTGU and entities with which the Company had affiliate transactions
5 during the test year. The chart contains wholly owned subsidiaries of WTG
6 Downstream LLC, including WTG Fuels Holdings LLC, WTG Downstream
7 Services, LLC (“WTGDS”), and WTG Downstream Holdings LLC (“WTG
8 Downstream”), which is the direct parent entity of WTGU and is ultimately owned
9 80% by Stonepeak Remuda Investment Holdings LLC and 20% by the Estate
10 of James L. Davis. The holding companies under WTG Downstream LLC are
11 energy-related businesses (e.g., gathering, processing, transmission, gas marketing,
12 and refined fuel retailer).

13 **Q. FOR EACH AFFILIATE OF WTGU, PLEASE DESCRIBE THE NATURE**
14 **OF ITS BUSINESS WITH WTGU DURING THE TEST YEAR.**

15 A. As shown in Schedule I-2, test year charges paid to affiliates are as follows:
16 Line 11: WTG Gas Marketing, LLC (“WTGGM”) provides gas procurement
17 services to WTGU for nearly all of WTGU’s distribution systems.
18 WTG utilizes WTGGM for gas procurement in order to benefit from
19 WTGGM’s volumetric advantages (e.g., transportation discounts,
20 imbalance accounting thresholds, and purchasing power). WTGGM
21 does not markup its gas supply to WTGU. WTGGM gas cost is
22 calculated and invoiced to WTGU at cost (inclusive of direct costs only,
23 meaning costs of commodity, upstream transport, and balancing costs).

1 Gas supply from WTGGM is made available to WTGU at lower prices
2 than gas supply available from third parties.

3 Line 14: WGI is the upstream interstate transmission pipeline operator that
4 provides transportation service to several WTGU distribution systems
5 in Sherman and Moore Counties, Texas. WTGU pays WGI for firm
6 transportation service pursuant to WGI's FERC-approved tariff rates.

7 Lines 17-19: For approximately half of the test year, WTGU purchased a
8 significant portion of its fleet gasoline and diesel supplies from WTG
9 Fuels, LLC ("WTGF") by utilizing WTGF's GasCard fleet management
10 system to control fuel usage in WTGU company vehicles. Vehicle fuel
11 is usually purchased by WTGU personnel at retail sites that are owned
12 and operated by third parties. Fuel is paid using the GasCard fleet
13 system. The price WTGU paid to WTGF was the posted price that is
14 offered to all retail customers at these sites, including other WTGU
15 affiliates and non-affiliated third parties. In June 2023, Quarles
16 Petroleum acquired WTGF, and WTGF is no longer an affiliate of the
17 Company. Occasionally, WTGU purchases oils, lubes, or propane parts
18 at a WTGF warehouse facility. These are usually small and inexpensive
19 items that are purchased at the market price available to any WTGF
20 affiliate or third party.

21 Line 25: WTGU receives administrative and other support services from
22 WTGDS. This affiliate charge is addressed in more detail in testimony
23 below and in Ms. Edgmon's direct testimony.

1 **Q. ARE THERE ANY PAYMENTS MADE TO AFFILIATES DURING THE**
2 **TEST YEAR THAT ARE NOT REFLECTED IN SCHEDULE I-2, AS**
3 **AMENDED?**

4 A. Yes. WTGU did not schedule out certain payments made to, or received from,
5 affiliates that fall into two categories:

- 6 • Balance Sheet items that do not represent an income or expense item to
7 WTGU or the affiliate (e.g., dividend payments); or
- 8 • An item paid to, or received from, affiliates that do not represent a revenue
9 item to WTGU or the affiliate, but is an expense pass-through from a non-
10 affiliated third party (e.g., vendors that combine goods or services to multiple
11 companies on a single invoice, accounting errors where a vendor bills an
12 incorrect company for goods or services).

13 **Q. PLEASE DESCRIBE THE SUPPORT SERVICES PROVIDED BY WTGDS**
14 **REFLECTED IN SCHEDULE I-2.**

15 A. WTGDS provides various administrative personnel and necessary support services
16 for WTGU's Midland administrative offices. For purposes of this rate case, the
17 cost of items and support services from WTGDS were allocated among WTGU and
18 affiliates. The allocation methodology is documented in a Cost Allocation Manual,
19 which is discussed in direct testimony provided by Ms. Edgmon along with other
20 information related to WTGDS.

21 **Q. ARE THERE BENEFITS OF A CENTRALIZED CORPORATE SUPPORT**
22 **SERVICE STRUCTURE?**

23 A. Yes. Without the centralized corporate services provided by WTGDS, it would be
24 necessary for WTGU to add administrative and professional staff positions to
25 maintain its accounts payable, human resources, tax compliance, risk management,

1 and information technology functions. By sharing these services with other
2 affiliates, WTGU recognizes significant savings in salaries and related overhead.

3 **Q. CONSIDERING THE ORGANIZATIONAL CHART IN SCHEDULE I-1**
4 **AND THE AFFILIATE TRANSACTIONS DURING THE TEST YEAR, DO**
5 **YOU HAVE ANY OBSERVATIONS RELATED TO WTGU'S**
6 **OPERATIONS UNDER A DIFFERENT CORPORATE STRUCTURE**
7 **THAN THE ONE THAT EXISTED DURING THE LAST RATE CASE?**

8 A. Even though the overall corporate structure surrounding WTGU has changed, that
9 has not affected WTGU's operations and its continued focus on providing safe and
10 reliable service to customers. WTGU still procures gas from WTGGM and still
11 receives corporate support services from the same entity and employees it has for
12 the last several years. In addition, the number of affiliate transactions decreased in
13 2023 compared to the test year in the Company's prior rate case.

14 **XII. RATE CASE EXPENSE RECOVERY**

15 **Q. DOES WTGU SEEK RECOVERY OF REASONABLE RATE CASE**
16 **EXPENSES?**

17 A. Yes. Based on GURA § 104.051 and Commission Rule § 7.5530, WTGU seeks
18 recovery of its reasonable rate case expenses as well as any reasonable rate case
19 expenses WTGU reimburses to the cities affected by this rate filing. These
20 expenses include costs for attorneys and consultants and other reasonable expenses
21 the Company incurs associated with this case. WTGU requests that reasonable rate
22 case expenses be recovered through a surcharge. The amount of costs to be
23 recovered should be determined at a point during the case when those expenses
24 have actually been incurred.

1 **Q. WHAT IS THE STATUS OF THE COMPANY’S RECOVERY OF RATE**
2 **CASE EXPENSES FROM THE LAST RATE CASE?**

3 A. Since the final order was issued in the last rate case, WTGU has made annual
4 compliance filings. As of May 31, 2024, WTGU must collect a remaining balance
5 of \$59,850.84. WTGU expects it will collect the remaining rate case expense
6 balance by the end of 2024. WTGU plans to stop charging the surcharge when the
7 amounts have been fully recovered, in accordance with the Rate Case Expense
8 Surcharge rate schedules that were approved in the last rate case. If, for some
9 reason, the Company has not fully recovered the authorized amount of rate case
10 expenses, the Company will voluntarily discontinue the surcharge as of December
11 31, 2024.

12 **XIII. GAS SUPPLY AND GAS COST ADJUSTMENT CLAUSE**

13 **A. Gas Cost Adjustment Clause**

14 **Q. HOW DOES WTGU RECOVER ITS COST OF GAS?**

15 A. WTGU’s Commission-approved GCA clause has several components that capture
16 gas purchase costs, upstream transportation costs, and any applicable revenue-
17 related taxes, fees, or other charges imposed by regulatory and governmental
18 authorities. The GCA clause establishes how these gas cost components are
19 calculated and passed through to customers. WTGU calculates a monthly gas cost
20 estimate and updates its GCA on a monthly basis. WTGU provides the
21 Commission with an annual reconciliation of actual gas costs versus the monthly
22 estimated filings. Any over- or under-collection balances are calculated and
23 correction factors are applied prospectively to ensure that WTGU collects only its
24 allowed cost of gas.

1 **Q. ARE ANY GAS COSTS INCLUDED IN THE MONTHLY CUSTOMER**
2 **CHARGE OR CONSUMPTION CHARGE UNDER WTGU'S OTHER**
3 **TARIFFS?**

4 A. No. All gas costs are recovered through the GCA clause.

5 **Q. IS WTGU PROPOSING ANY CHANGES TO ITS GCA CLAUSE?**

6 A. No.

7 **Q. IS THERE A NEED TO CONTINUE WTGU'S GCA CLAUSE?**

8 A. Yes. The GCA clause was approved by the Commission in GUD No. 9488
9 Consolidated and has been in effect since then. The GCA clause functions well in
10 today's gas markets. The continued use of WTGU's GCA clause operates to ensure
11 that WTGU neither over-recovers nor under-recovers its cost of gas, and that
12 WTGU customers pay only the Company's actual gas cost, including its authorized
13 components.

14 **Q. HOW ARE NATURAL GAS PRICES ESTABLISHED?**

15 A. Natural gas is a commodity with the prices of natural gas established as a function
16 of supply and demand. The availability of gas will affect prices. Increases in gas
17 supply result in lower prices, and prices increase as supply decreases.

18 **Q. WHAT ARE THE FACTORS THAT AFFECT THE PRICE OF DOMESTIC**
19 **NATURAL GAS PRODUCTION?**

20 A. On the supply side, variations in the amount of gas being produced, the amount of
21 gas in storage and the amount of gas being imported or exported will affect prices.
22 On the demand side, the factors that affect natural gas prices include the strength
23 of the economy. A weak economy usually means lower prices and economic

1 growth usually means higher prices. Weather is another important factor. Severe
2 weather such as hurricanes and extreme low temperatures can affect supplies as
3 well as demand. Winter weather has an effect on domestic and non-domestic
4 customers. A third factor affecting demand for natural gas is the price of oil.
5 Competition from other fuels can lead to large industrial and electrical generating
6 customers switching fuels and the demand, or lack thereof, can affect prices. Other
7 factors include pipeline capacity and pipeline outages.

8 **Q. WILL THE PRICE FOR NATURAL GAS CONTINUE TO CHANGE?**

9 A. Yes. All the factors that have caused historical price changes still exist, and
10 changes in gas prices will continue into the future.

11 **Q. DOES WTGU HAVE THE ABILITY TO CONTROL THE PRICES IT PAYS**
12 **FOR GAS PURCHASES?**

13 A. No. Prices for the commodity are established through a free market system based
14 on supply and demand. WTGU has no control in establishing these gas prices.
15 However, WTGU continually works to acquire a cost effective and reliable gas
16 supply for its distribution systems.

17 **B. Gas Supply Practices**

18 **Q. FROM WHAT ENTITIES DOES WTGU TYPICALLY PURCHASE GAS**
19 **SUPPLY?**

20 A. WTGU purchases a portion of its gas supply from suppliers that are directly
21 connected to WTGU distribution systems, i.e., where there is no intermediary
22 pipeline between WTGU and the supplier. DCP Midstream, Energy Transfer and
23 Paisano Energy represent some of these direct WTG suppliers.

1 In addition, most of the gas that is delivered to WTGU distribution systems
2 through upstream third-party transmission lines is supplied by an affiliate,
3 WTGGM. WTGGM purchases natural gas supply from numerous affiliated and
4 unaffiliated gas producers, gas processors, and natural gas marketing companies.
5 Examples of unaffiliated gas producers and processors include Mercuria Energy,
6 Energy Transfer, DCP Midstream, and Kinder Morgan. Examples of unaffiliated
7 natural gas marketing companies include Oneok Energy Services, Tenaska
8 Marketing, Conoco, Energy Transfer and Concord Energy.

9 **Q. PLEASE EXPLAIN THE GAS PURCHASING PRACTICES USED TO**
10 **SUPPLY WTG DISTRIBUTION SYSTEMS.**

11 A. Generally, the daily gas supply requirements on the upstream pipelines serving
12 WTGU's distribution systems are projected each month. These projections are
13 based on historical quantities as well as current business and weather conditions.
14 Once the projected requirements are determined, the supplies are purchased by
15 WTGGM. These supplies are delivered into various upstream transmission
16 systems and transported to WTGU's distribution systems. Some of these
17 transporting pipelines include Atmos Energy, Oneok WesTex, El Paso Natural Gas,
18 Northern Natural Gas, Colorado Interstate Gas, Kinder Morgan, and two WTGU
19 affiliates, Western Gas Interstate Company and WTG Gas Transmission Company.
20 Most of the gas supplies are purchased by WTGGM on a month-to-month base load
21 basis at negotiated index-based or fixed prices. Some third-party supplies are
22 purchased for longer terms at either negotiated index-based or fixed prices. Some
23 daily gas purchases are made at Gas Daily published prices or fixed prices, as

1 necessary, to meet contract balancing commitments on transporting pipelines
2 upstream of WTGU systems.

3 **Q. PLEASE EXPLAIN WHY A LARGER PORTION OF WTGU'S GAS**
4 **SUPPLY IS NOT PURCHASED AT A FIXED PRICE FOR EXTENDED**
5 **PERIODS OF TIME.**

6 A. The goal is to purchase gas at prices that reflect the current market. Fixed price
7 purchases for extended time periods invariably do not reflect the current market,
8 making them difficult to explain to WTGU's customers. If WTGU purchased a
9 large segment of its gas supply at a fixed price for long periods of time, it would
10 not be able to purchase gas at market prices as the price of gas changes.

11 **Q. DOES WTGU HEDGE THE PRICE OF ANY OF ITS GAS SUPPLY?**

12 A. WTGU does not directly hedge the price of any gas supplies. However, on
13 occasion, WTGU will request that WTGGM hedge its gas supply costs in order to
14 provide WTGU with a fixed gas cost.

15 **C. Affiliate Gas Supply Purchases**

16 **Q. DOES WTGU PURCHASE GAS FROM ANY AFFILIATES?**

17 A. Yes, it does. WTGU purchases gas from WTGGM.

18 **Q. HOW DO YOU DETERMINE A FAIR PRICE TO PAY FOR THE**
19 **AFFILIATE GAS SUPPLY?**

20 A. WTGGM sells gas to WTGU at its cost, inclusive of all applicable transport and
21 imbalance charges from pipelines upstream of WTGU's systems.

1 **Q. HOW DO YOU ENSURE THAT WTGU GETS COMPETITIVE BIDS AND**
2 **PRICES FROM BOTH AFFILIATED AND UNAFFILIATED GAS**
3 **SUPPLIERS?**

4 A. Competitive pricing is assured by obtaining market knowledge. Market knowledge
5 is collected through discussion and negotiation with various suppliers and markets
6 and information obtained from the Intercontinental Exchange, a commodity trading
7 platform posting actual real-time sales and purchases transactions at various points
8 across the United States.

9 **Q. CAN WTGU REDUCE GAS SUPPLY COSTS BY PURCHASING GAS**
10 **FROM UNAFFILIATED SUPPLIERS?**

11 A. No, WTGU would not reduce supply costs by purchasing from unaffiliated
12 suppliers. WTGGM controls significant gas supplies on the upstream pipelines
13 serving WTGU distribution systems that are well in excess of volumes required by
14 WTGU. These large quantities, controlled by WTGGM, provide WTGU with
15 transportation discounts and imbalance thresholds that would not be available to
16 WTGU if it were to purchase on a stand-alone basis. If WTGU did not purchase
17 from WTGGM, its customers would be paying higher costs for natural gas.

18 **Q. WHAT ARE THE TERMS CONTAINED IN THE GAS SUPPLY**
19 **AGREEMENTS BETWEEN WTGU AND WTGGM?**

20 A. WTGGM sells gas to WTGU under a standard North American Energy Standards
21 Board agreement. The price paid by WTGU is WTGGM's weighted average cost
22 of gas on the applicable upstream pipeline making deliveries to specific WTGU
23 distribution systems, inclusive of any transportation and imbalance charges.

1 **Q. WHAT ADVANTAGES DO WTGU CUSTOMERS RECEIVE DUE TO**
2 **WTGU PURCHASING THE MAJORITY OF ITS GAS SUPPLIES FROM**
3 **AFFILIATE WTGGM?**

4 A. The biggest advantage WTGU and its customers receive results from WTGGM's
5 economies of scale achieved by pairing WTGU supply and transport needs with
6 WTGGM's increased load profile. WTGU also saves labor costs by sharing gas
7 supply personnel between WTGU and WTGGM, and there is reduced credit
8 support required.

9 **Q. DOES WTGGM SELL GAS TO UNAFFILIATED THIRD PARTIES AT**
10 **THE SAME PRICE IT SELLS GAS TO WTG?**

11 A. No. WTGGM sells gas to WTGU at cost. WTGGM sells gas to unaffiliated third
12 parties at higher prices.

13 **XIV. WINTER STORM URI**

14 **A. Overview & Operational Activities**

15 **Q. DESCRIBE WINTER STORM URI IN GENERAL TERMS.**

16 A. Winter Storm Uri was a major weather event that occurred in February 2021 and
17 affected all of Texas and large parts of the United States. Governor Greg Abbott
18 issued a Disaster Declaration on February 12, 2021, for all 254 counties in Texas
19 due to severe weather from Winter Storm Uri posing an imminent threat of
20 widespread and extreme property damage, injury and loss of life due to prolonged
21 freezing temperatures, heavy snow and freezing rain statewide.⁴ From February

⁴ Proclamation by the Governor of the State of Texas: Governor Abbott Issues Disaster Declaration In Response To Severe Winter Weather In Texas (Feb. 12, 2021) available at <https://gov.texas.gov/news/post/governor-abbott-issues-disaster-declaration-in-response-to-severe-winter-weather-in-texas>.

1 13-23, 2021, parts of Texas, including the areas where the Company provides
2 natural gas service, experienced unprecedented cold temperatures that stressed
3 utility systems statewide and drastically increased the demand for natural gas so
4 customers could heat their homes and businesses.

5 **Q. WHAT AREAS OF THE COMPANY’S SYSTEM WERE AFFECTED BY**
6 **WINTER STORM URI?**

7 A. All parts of WTGU’s distribution and transmission systems were subjected to the
8 weather conditions, but they did not suffer negative effects during the Winter Storm
9 as pressures remained strong. The Company did not lose service to any customers.

10 **Q. IS WTGU REQUIRED TO PROVIDE SAFE AND RELIABLE SERVICE**
11 **TO ITS CUSTOMERS, EVEN UNDER EXTREME WEATHER**
12 **CONDITIONS?**

13 A. Yes. In addition, on February 12, 2021, the Commission issued an Emergency
14 Order directing gas utilities to prioritize service to human needs customers, even if
15 that meant reducing gas deliveries to non-residential or non-human needs
16 customers.

17 **Q. WHAT STEPS DID WTGU TAKE TO PREPARE ITS SYSTEM FOR**
18 **WINTER STORM URI?**

19 A. WTGU, as with every winter season, prepares for colder weather well in advance
20 and actively makes sure its system and procedures are prepared for any weather-
21 related issues that may arise.

1 **B. Gas Procurement and Purchases During Winter Storm Uri**

2 **Q. DID THE COMPANY UNDERTAKE REASONABLE GAS SUPPLY**
3 **PLANNING AND PROCUREMENT ACTIVITIES IN ANTICIPATION OF**
4 **THE 2020/2021 WINTER HEATING SEASON?**

5 A. Yes, which is consistent with the Company’s normal annual and monthly gas
6 supply planning activities.

7 **Q. COULD THE COMPANY HAVE PREDICTED WINTER STORM URI**
8 **AND ITS CONSEQUENCES FOR NATURAL GAS MARKET PRICES?**

9 A. No, Winter Storm Uri was unprecedented. The infrastructure challenges, resulting
10 disruptions in natural gas supply, high natural gas prices, and record demand for
11 natural gas were a surprise to the entire industry.

12 **Q. LEADING UP TO WINTER STORM URI, WHAT GAS PROCUREMENT**
13 **STEPS DID WTGU TAKE?**

14 A. When the Winter Storm was predicted, WTGU began the process of securing
15 additional natural gas supplies for WTGU’s systems and customers.

16 **Q. CAN WTGU CONTROL PRICES FOR NATURAL GAS?**

17 A. No. The price of natural gas is subject to competitive market forces well outside
18 the Company’s control. In addition, the Company’s gas contracts with suppliers
19 are primarily baseload agreements for monthly supply. Any additional gas that was
20 required was bought at a daily price that during the Winter Storm, escalated to
21 historical highs.

22 **Q. HOW MUCH GAS DID WTGU PURCHASE DURING FEBRUARY 2021**
23 **TO PROVIDE SERVICE TO CUSTOMERS?**

24 A. The Company purchased 1,542,313 Mcfs.

1 **Q. HOW DOES THAT COMPARE TO TYPICAL GAS REQUIREMENTS**
2 **DURING THE SAME TIME OF YEAR IN PRIOR YEARS OR SINCE**
3 **THEN?**

4 A. Due to the Winter Storm event, the February 2021 purchases were higher than prior
5 February natural gas purchases. For example, in February 2020, WTGU purchased
6 1,347,589 Mcfs.

7 **Q. COULD WTGU HAVE OBTAINED NATURAL GAS FROM ANY OTHER**
8 **SOURCES DURING THE STORM?**

9 A. No.

10 **Q. WAS WTGU REQUIRED TO TIMELY PAY NATURAL GAS INVOICES**
11 **AS THE COMPANY RECEIVED THEM?**

12 A. Yes.

13 **Q. WHAT TYPES OF COSTS ARE INCLUDED IN THE GAS COSTS WTGU**
14 **INCURRED TO PROVIDE SERVICE DURING WINTER STORM URI?**

15 A. Costs included were typical with most other months, including the commodity
16 price, along with upstream transportation and fuel rates. Also, there is no markup
17 or profit included in any of the Company's gas cost amounts, as WTGU purchases
18 gas from WTGGM.

19 **Q. PLEASE EXPLAIN ANY PENALTIES WTGU WAS CHARGED RELATED**
20 **TO NATURAL GAS PURCHASES DURING WINTER STORM URI.**

21 A. Any pipeline penalty incurred by WTGU's supplier would have been passed
22 through to WTGU.

1 **Q. DID WTGU CHALLENGE ANY OF THE PENALTIES SUPPLIERS**
2 **ASSESSED TO THE COMPANY?**

3 A. WTGU's supplier, WTGGM, did challenge some of the penalties that were
4 assessed by pipelines during the Winter Storm. When WTGGM was successful in
5 challenging the penalties, they were not included on the invoice WTGGM sent to
6 WTGU. If WTGGM was not successful in challenging the penalties, the amounts
7 were included on the invoice WTGGM sent to WTGU.

8 **Q. DOES WTGU HAVE DOCUMENTATION TO SUPPORT THE**
9 **EXTRAORDINARY GAS COSTS IT SEEKS TO RECOVER?**

10 A. Yes. Copies of the invoices the Company received from suppliers are attached to
11 my testimony as Confidential Exhibit JJK-2. In addition, Confidential
12 Exhibit JJK-3 is a copy of the Company's gas supply contract that was in effect
13 during Winter Storm Uri.

14 **Q. WHAT PROCESS DOES WTGU HAVE IN PLACE TO CONFIRM ITS GAS**
15 **PURCHASES ARE ACCURATE AND REASONABLE?**

16 A. WTGGM's and WTGU's gas supply personnel review invoices for gas supply for
17 accuracy as to pricing and volumes, and those items are approved before being sent
18 to accounting for payment.

19 **Q. WHAT STEPS DID WTGU TAKE TO ENSURE THE GAS COSTS WERE**
20 **REASONABLE AND NECESSARY?**

21 A. As the Company received invoices, each invoice went through the standard
22 approval process for approving gas cost invoices. The Company has a multi-step
23 approval process during which the Gas Supply Manager and myself as VP of Gas

1 Marketing reviewed and approved invoices for accuracy and reasonableness. Ms.
2 Edgmon addresses this in more detail in her direct testimony.

3 **Q. ARE ANY AFFILIATE COSTS INCLUDED IN THE COMPANY'S**
4 **EXTRAORDINARY GAS COSTS?**

5 A. Yes, all of the Company's extraordinary gas costs are affiliate costs because WTGU
6 purchases gas supplies from WTGGM. I addressed this in detail in Section XIII(C)
7 of my testimony, including an explanation of how these amounts comply with the
8 applicable affiliate standard. In addition, the costs were reasonable and necessary
9 because the Company was required to purchase natural gas to ensure customers
10 continued to have service during Winter Storm Uri. In addition, the costs were
11 reasonable because the Company experienced the same high natural gas costs that
12 existed throughout the state during the Winter Storm.

13 **Q. DID THE COMPANY TAKE ON ANY DEBT TO FINANCE THE**
14 **EXTRAORDINARY GAS COSTS IT EXPERIENCED DURING WINTER**
15 **STORM URI?**

16 A. No. To avoid delays in procuring natural gas and potential disruptions in service,
17 the Company paid the gas costs "out of pocket" without any debt financing. In
18 addition, there were not any readily available options for the Company to obtain
19 financing, so the Company made the reasonable decision to proceed with paying
20 for the costs itself. This means that WTGU has been carrying these gas costs on its
21 books since February 2021.

1 **C. Extraordinary Gas Cost Recovery**

2 **Q. HOW DOES THE COMPANY TYPICALLY RECOVER ITS NATURAL**
3 **GAS COSTS?**

4 A. The Company recovers its natural gas costs through the terms and conditions of the
5 GCA clause that has been approved by the Commission.

6 **Q. DID THE COMPANY BILL CUSTOMERS AND/OR RECOVER ANY OF**
7 **ITS FEBRUARY 2021 GAS COSTS THROUGH THE GCA?**

8 A. Yes, the Company billed its jurisdictional customers a total of \$906,503.71 in gas
9 costs in February 2021. This amount was determined by taking the total February
10 2021 billed sales volumes for each gas cost zone (North, West and South) and
11 multiplying it by the purchased gas factor and was in line with gas costs customers
12 were accustomed to being billed as shown in the January, February, and March
13 2021 customer bills and other documents included in my workpapers.

14 **Q. WAS BILLING CUSTOMERS IN THAT MANNER CONSISTENT WITH**
15 **THE COMPANY’S GCA?**

16 A. Yes, it was.

17 **Q. HOW DID THE COMPANY DETERMINE THE AMOUNT OF**
18 **EXTRAORDINARY GAS COSTS INCLUDED IN THE REGULATORY**
19 **ASSET THE COMPANY SEEKS TO RECOVER IN THIS PROCEEDING?**

20 A. Only extraordinary gas costs were recorded to the regulatory asset. Ordinary or
21 typical gas cost amounts for February 2021 were not included in the asset. Using
22 this approach, WTGU has ensured that only expenses that would not have been
23 incurred but for Winter Storm Uri are included in the regulatory asset. This
24 calculation is set forth in Ms. Edgmon’s testimony.

1 **Q. HOW IS THE COMPANY PROPOSING TO RECOVER THE**
2 **EXTRAORDINARY GAS COSTS IT INCURRED DURING WINTER**
3 **STORM URI?**

4 A. To avoid a high bill impacts, the Company proposes to recover the total amount
5 over 5 years through a separate charge on customers' bills to allow the Company
6 to easily track charges and cost recovery amounts. A calculation of that amount
7 using adjusted customer volumes for the end of the test year is attached to my
8 testimony as Exhibit JJK-4. In addition, the Company's proposed Winter Storm
9 Rider to recover these costs is included as Exhibit JJK-5.

10 **Q. WHY IS THE COMPANY REQUESTING RECOVERY OF WINTER**
11 **STORM URI EXTRAORDINARY GAS COSTS AT THIS TIME?**

12 A. The Company has been able to carry these amounts on its books since February
13 2021 and doing so did not present challenges to the Company's financial situation
14 at the time the costs were incurred or since then. For that reason, it was not
15 necessary for WTGU to participate in the securitization process the Legislature
16 authorized. This rate case is the next opportunity for the Company to request
17 recovery of these costs following a review of their reasonableness and accuracy.

18 **Q. IN ADDITION TO THE GAS COSTS, ARE THERE OTHER AMOUNTS**
19 **WTGU SEEKS TO RECOVER AS PART OF ITS EXTRAORDINARY GAS**
20 **COSTS IN THIS CASE?**

21 A. No. Although the Company has been carrying the approximately \$3.5 million in
22 extraordinary gas costs on its books since the Winter Storm, the Company is not
23 seeking to recover carrying costs. If the Company were to request carrying costs,

1 they would amount to approximately \$1.2 million calculated using the Company's
2 weighted average cost of capital.

3 **XV. PROPOSED TARIFFS**

4 **Q. IS WTGU PROPOSING CHANGES TO ITS CURRENT TARIFFS?**

5 A. Yes, Exhibit A to the Statement of Intent is a copy of the proposed tariffs that
6 includes the proposed rates and related terms of service for WTGU.

7 **Q. WHAT ARE THE CHANGES PROPOSED TO WTGU'S TARIFFS?**

8 A. WTGU's current tariffs consist of rates approved by the Commission in Docket
9 No. OS-20-00004347. WTGU proposes the following changes:

- 10 • Increasing rates for domestic and non-domestic customers to reflect the
11 Company's higher cost of service;
- 12 • Updating the tariff formatting;
- 13 • Adding the Winter Storm Cost Recovery Rider to the Company's existing
14 tariffs to recover reasonable and necessary extraordinary gas costs;
- 15 • Removing the EDIT Credit Rider because the credits have been fully
16 returned to customers; and
- 17 • Making non-substantive changes to the Pipeline Safety Fee Rider.

18 WTGU does not propose to change the fee, deposit, or general terms of service
19 provisions in the tariffs.

20 **XVI. CONCLUSION**

21 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

22 A. Yes, it does.

STATE OF TEXAS §
COUNTY OF MIDLAND §

AFFIDAVIT OF JACK J. KING

BEFORE ME, the undersigned authority, on this day personally appeared Jack J. King, who having been placed under oath by me did depose as follows:

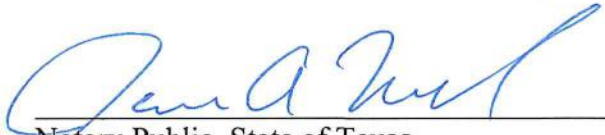
1. "My name is Jack J. King. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is Vice President of Gas Marketing for West Texas Gas Utility, LLC.
2. I have prepared the foregoing direct testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

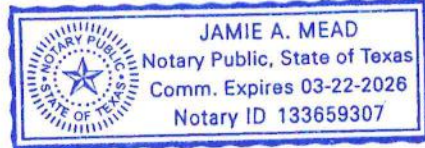


 Jack J. King

SUBSCRIBED AND SWORN TO BEFORE ME by the said Jack J. King on this 27th day of June 2024.



 Notary Public, State of Texas



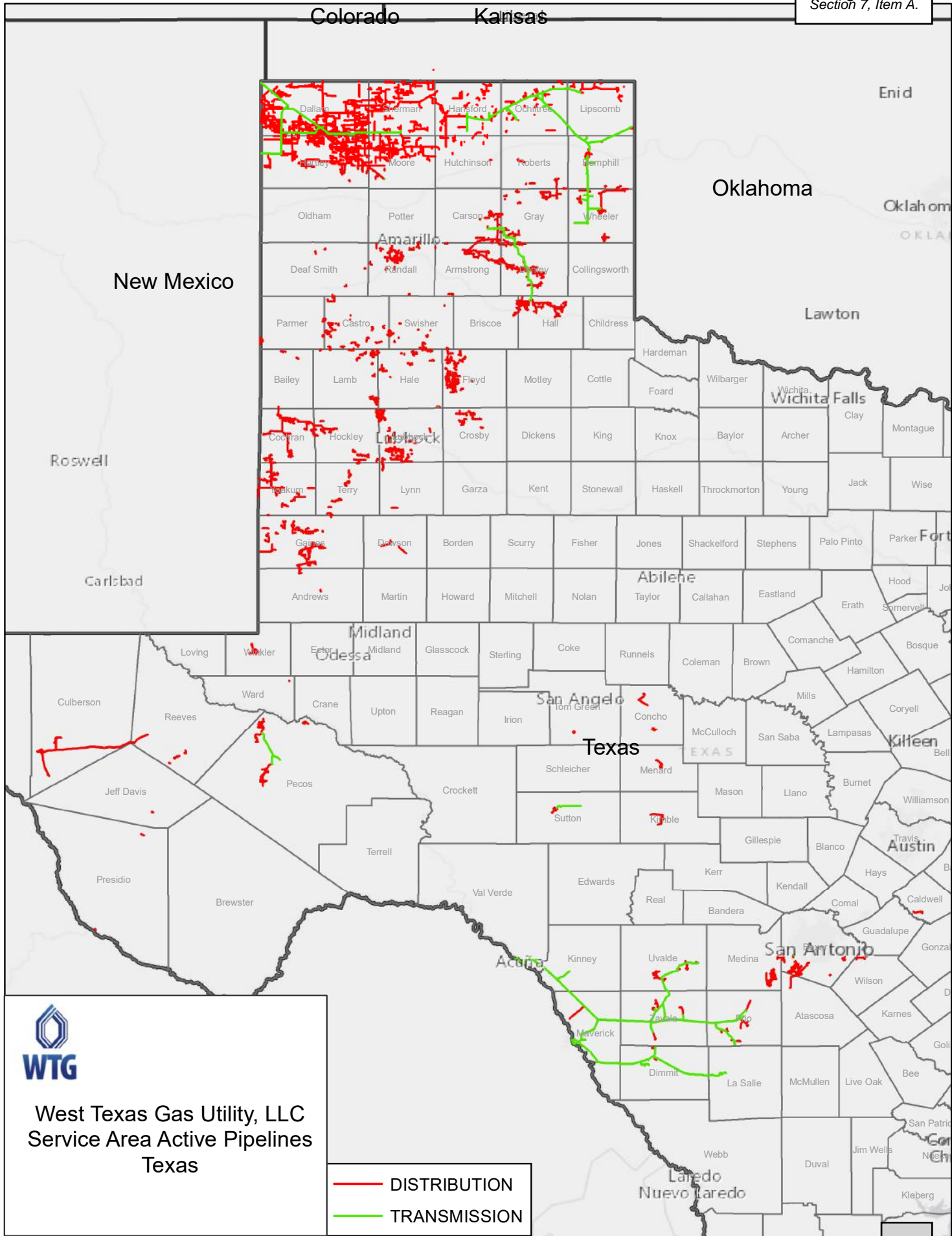


Exhibit JJK-2 is Confidential
and will be provided pursuant to the terms of the
Protective Agreement

Exhibit JJK-3 is Confidential
and will be provided pursuant to the terms of the
Protective Agreement

Winter Storm Surcharge Calculation

Total Extraordinary Gas Costs	\$ 3,502,862.41
Non-Domestic Volumes (Sch A)	634,364
Domestic Volumes (Sch A)	<u>1,063,235</u>
Total Volumes (Mcf)	1,697,599
Recovery Period in Years	5
Total Recovery Period Annualized Mcf	8,487,995
Winter Storm Surcharge per Mcf	\$ 0.41

WEST TEXAS GAS UTILITY, LLC

Page 1 of 2

Effective: _____

RATE SCHEDULE
WINTER STORM RIDER

Section 7, Item A.

WINTER STORM URI SURCHARGE**APPLICABILITY**

All jurisdictional customers in the unincorporated or environs areas of West Texas Gas Utility, LLC (“WTGU”) Service Area.

PURPOSE

The purpose of the Winter Storm Uri Surcharge is to authorize WTGU to recover the reasonable, necessary, and prudent extraordinary gas costs incurred by WTGU as a result of Winter Storm Uri. The rate schedule is authorized by the Railroad Commission of Texas’s (“Commission”) Final Order in Case No. OS-24-00017816, which approved a Winter Storm Uri Regulatory Asset and the recovery of the costs contained in the regulatory asset through a monthly surcharge. WTGU is authorized and directed to assess the Winter Storm Uri Surcharge rate as set forth in the section below.

SURCHARGE RATE

All Mcf during each billing period: \$0.41 per Mcf.

This rate will be in effect until all approved and expended Winter Storm Uri costs, up to \$3,502,862.41 (“Regulatory Asset Amount”), are recovered under the applicable rate schedules. Any excess recovery of the Regulatory Asset Amount shall be calculated and refunded to customers through a final true-up under this rate schedule.

OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

CONDITIONS

1. Subject to all applicable laws and orders, and WTGU’s rules and regulations on file with the regulatory authority.
2. Uncollectible amounts, actually written off, associated with this surcharge shall be added back to the balance to be recovered via this surcharge.
3. Any amounts that were included in the Regulatory Asset Amount that are refunded to WTGU subsequent to the Final Order in Case No. OS-24-00017816 shall be subtracted from the balance and shall not be recovered via this surcharge.

WEST TEXAS GAS UTILITY, LLC

Page 2 of 2

Effective: _____

RATE SCHE
WINTER STORM RIDER

Section 7, Item A.

WINTER STORM URI SURCHARGE RECOVERY COMPLIANCE REPORT

WTGU shall file a reconciliation report annually on or before March 31, commencing in 2026 and ceasing after a reconciliation report is filed at the end of the month following the month in which the Regulatory Asset Amount is fully recovered via the final reconciliation true-up (if applicable). WTGU shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing Case No. OS-24-00017816, Winter Storm Uri Surcharge Recovery Report. The report shall include:

- The volumes used by month by customer class during the applicable period;
- The amount of surcharge recovered, by month;
- The outstanding balance, by month;
- The associated uncollectibles, by month; and
- Any credits for amounts WTGU received that would offset the Regulatory Asset Amount

Reports for the Commission should be filed electronically at
GUD_Compliance@rrc.texas.gov or at the following address:

Compliance Filing
Director of Oversight and Safety Division
Gas Services Dept.
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

WEST TEXAS GAS UTILITY, LLC

Page 1 of 2

Effective: _____

RATE SCHEDULE
WINTER STORM RIDER

Section 7, Item A.

WINTER STORM URI SURCHARGE

APPLICABILITY

All Jurisdictional customers in the incorporated areas or cities in West Texas Gas Utility, LLC's ("WTGU") Texas Service Area.

PURPOSE

The purpose of the Winter Storm Uri Surcharge is to authorize WTGU to recover the reasonable, necessary, and prudent extraordinary gas costs incurred by WTGU as a result of Winter Storm Uri. The rate schedule is authorized by the Railroad Commission of Texas's ("Commission") Final Order in Case No. OS-24-00017816 and by cities that approved the corresponding request WTGU made with incorporated regulatory authorities, which approved a Winter Storm Uri Regulatory Asset and the recovery of the costs contained in the regulatory asset through a monthly surcharge. WTGU is authorized and directed to assess the Winter Storm Uri Surcharge rate as set forth in the section below.

SURCHARGE RATE

All Mcf during each billing period: \$0.41 per Mcf.

This rate will be in effect until all approved and expended Winter Storm Uri costs, up to \$3,502,862.41 ("Regulatory Asset Amount"), are recovered under the applicable rate schedules. Any excess recovery of the Regulatory Asset Amount shall be calculated and refunded to customers through a final true-up under this rate schedule.

OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

CONDITIONS

1. Subject to all applicable laws and orders, and WTGU's rules and regulations on file with the regulatory authority.
2. Uncollectible amounts, actually written off, associated with this surcharge shall be added back to the balance to be recovered via this surcharge.

WEST TEXAS GAS UTILITY, LLC

Page 2 of 2

Effective: _____

RATE SCHE
WINTER STORM RIDER

Section 7, Item A.

3. Any amounts that were included in the Regulatory Asset Amount that are refunded to WTGU subsequent to the Final Order in Case No. OS-24-00017816 shall be subtracted from the balance and shall not be recovered via this surcharge.

WINTER STORM URI SURCHARGE RECOVERY COMPLIANCE REPORT

WTGU shall file a reconciliation report annually on or before March 31, commencing in 2026 and ceasing after a reconciliation report is filed at the end of the month following the month in which the Regulatory Asset Amount is fully recovered via the final reconciliation true-up (if applicable). WTGU shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing Case No. OS-24-00017816, Winter Storm Uri Surcharge Recovery Report. The report shall include:

- The volumes used by month by customer class during the applicable period;
- The amount of surcharge recovered, by month;
- The outstanding balance, by month;
- The associated uncollectibles, by month; and
- Any credits for amounts WTGU received that would offset the Regulatory Asset Amount

Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Compliance Filing
Director of Oversight and Safety Division
Gas Services Dept.
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

WORKPAPERS
TO
DIRECT TESTIMONY
OF
JACK J. KING

Workpapers to the Direct Testimony of Jack J. King are voluminous and are being provided in electronic format.

CASE NO. 00017816

**STATEMENT OF INTENT OF
WEST TEXAS GAS UTILITY, LLC TO
INCREASE GAS UTILITY RATES
WITHIN THE UNINCORPORATED
AREAS OF TEXAS**

§
§
§
§
§

**BEFORE THE
RAILROAD COMMISSION
OF TEXAS**

DIRECT TESTIMONY

OF

AMANDA EDGMON

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

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LIST OF EXHIBITS

EXHIBIT AE-1	FERC Cross Reference Table
EXHIBIT AE-2	WTGDS Cost Allocation Manual
EXHIBIT AE-3	GRIP Capital Expenditures

1 **DIRECT TESTIMONY OF AMANDA EDGMON**

2 **I. INTRODUCTION AND QUALIFICATIONS**

3 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

4 A. My name is Amanda Edgmon. My business address is 303 Veterans Airpark Lane,
5 Suite 5000, Midland, Texas 79705.

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

7 A. I am employed by West Texas Gas Utility, LLC (“WTGU” or the “Company”) as
8 the Treasurer and Secretary. I am also the Regulatory Accountant for WTGU.

9 **Q. WHAT ARE YOUR DUTIES AS THE TREASURER, SECRETARY AND**
10 **REGULATORY ACCOUNTANT?**

11 A. As the Treasurer, I supervise the Company’s cash management ensuring sufficient
12 funds are available to meet ongoing operational requirements. As the Secretary, I
13 execute and maintain all required corporate filings, documents, reports, and records
14 according to applicable laws and regulations. My Regulatory Accountant duties
15 include making all the accounting filings with the Railroad Commission of Texas
16 (“Commission”), the Oklahoma Corporation Commission and the Federal Energy
17 Regulatory Commission (“FERC”) on behalf of WTGU.

18 **Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL**
19 **EXPERIENCE.**

20 A. I graduated from Texas Tech University in 2009 with a bachelor’s degree in
21 Business Administration, majoring in Finance. I began my employment with
22 WTGU’s predecessor entity, West Texas Gas, Inc., upon graduation in May 2009
23 as a staff accountant. I became the Regulatory Accountant in 2013. In 2020, I was
24 elected as the Secretary and Treasurer of WTGU.

1 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY**
2 **COMMISSIONS?**

3 A. Yes, I filed testimony with the Commission in Docket No. OS-20-00004347.

4 **Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR**
5 **DIRECT SUPERVISION?**

6 A. Yes, it was.

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

9 A. Yes, I am sponsoring the exhibits listed in the table of contents.

10 **Q. ARE YOU SPONSORING OR CO-SPONSORING ANY SCHEDULES?**

11 A. Yes. I am co-sponsoring or sponsoring the following schedules:

12 B-1 Operations and Maintenance Expense

13 B-2 Administrative and General Expenses

14 C-5 Gas Reliability Infrastructure Program Additions

15 H-1 Payroll Summary

16 H-2 Payroll Analysis

17 H-3 Bad Debts

18 H-4 Advertising Expenses

19 H-5 Donation and Contributions

20 H-6 Lobbying Expenses

21 H-7 Penalties and Fine

22 H-8 Outside Services charged to A&G Accounts

23 H-9 Legal Expense Detail

1 H-10 Lost and Unaccounted for Gas

2 I-1 Organizational Chart

3 I-2 Charges by Affiliates to WTGU

4 I-3 Charges by Affiliates to Others

5 **Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR**
6 **SUPERVISION?**

7 A. Yes, they were.

8 **Q. HOW DOES YOUR TESTIMONY RELATE TO OTHER COMPANY**
9 **WITNESSES IN THIS RATE FILING?**

10 A. My testimony addresses the Company's books and records, confirms that the
11 Company has followed the Commission's rules when preparing and presenting its
12 filing package, presents plant investment records that are subject to a prudence
13 review in this case, presents the test-year, supports the recovery of WTG
14 Downstream Services, LLC ("WTGDS") costs, and supports recovery of the
15 Company's extraordinary gas costs from Winter Storm Uri. Company witnesses
16 Jack J. King and Matthew S. Smith support the reasonableness and necessity of
17 operations and maintenance ("O&M") expenses, administrative and general
18 ("A&G") expenses and capital investment presented in the filing, and Mr. King
19 also addresses Winter Storm Uri extraordinary gas costs. Additionally, Company
20 witness Dr. Bruce Fairchild supports the Company's overall cost of service,
21 requested return and cost of debt, and sponsors the majority of WTGU's rate filing
22 package schedules.

1 **II. PURPOSE OF TESTIMONY**

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

4 A. The purpose of my testimony is to attest to the accuracy of the Company's books
5 and records that were used to develop the rate study performed by Dr. Fairchild,
6 support the recovery of WTGDS costs and provide any supporting documentation
7 or information concerning the Company's financial records. I also address issues
8 related to the allocation factor that applies to jurisdictional customers, which
9 WTGU is seeking to change in this proceeding to better align the recovery of costs
10 from customers who benefit from the investment the Company makes. Finally, I
11 discuss the accounting aspects of the Company's request to recover extraordinary
12 gas costs incurred to provide service to customers during Winter Storm Uri.

13 **III. BOOKS AND RECORDS**

14 **Q. WOULD YOU BRIEFLY DESCRIBE THE METHOD BY WHICH WTGU'S**
15 **BOOKS AND RECORDS ARE MAINTAINED AND NOTE ANY**
16 **SIGNIFICANT CHANGES IN THOSE METHODS SINCE THE**
17 **COMPANY'S LAST RATE CASE?**

18 A. The books and records are maintained in accordance with Generally Accepted
19 Accounting Principles ("GAAP") and presented pursuant to the Uniform System of
20 Accounts ("USOA"), as prescribed by FERC, and the Commission. I have attached
21 a cross reference to this testimony (Exhibit AE-1), which shows the corresponding
22 FERC account number to WTGU's general ledger chart of accounts. Except for
23 revised depreciation rates pursuant to the Commission's final order, there have been
24 no significant changes in the methods by which the Company keeps its books and

1 records since WTGU presented its last full rate case in Docket No. OS-20-
2 00004347.

3 **Q. IN THE PROCESS OF PROVIDING TEST PERIOD DATA TO**
4 **DR. FAIRCHILD, DID YOU DISCOVER ITEMS IN THE COMPANY'S**
5 **BOOKS AND RECORDS THAT YOU NEEDED TO CORRECT?**

6 A. No, I did not.

7 **Q. ARE WTGU'S REVENUES AND EXPENSES FOR THE TEST YEAR, AS**
8 **SHOWN ON THE BOOKS AND RECORDS OF THE COMPANY, TRUE**
9 **AND CORRECT TO THE BEST OF YOUR KNOWLEDGE?**

10 A. Yes.

11 **Q. PLEASE SUMMARIZE HOW THE BOOKS AND RECORDS OF WTGU**
12 **ARE MAINTAINED AND UTILIZED IN THE REGULAR COURSE OF**
13 **BUSINESS.**

14 A. WTGU maintains its books and records in accordance with GAAP. They are
15 presented pursuant to the USOA. The USOA is the prescribed methodology for
16 maintaining records in all of the state jurisdictions that regulate WTGU's natural
17 gas distribution operations. These regulations are found and defined in the Code of
18 Federal Regulations, Title 18 – Conservation of Power and Water Resources,
19 Subchapter F – Accounts, Natural Gas Accounts, Part 201 – Uniform System of
20 Accounts. Commission Rule § 7.310 requires that the Company keep its books in
21 accordance with the FERC USOA. To demonstrate this compliance, the
22 corresponding FERC accounts are included in the required schedules in this filing.
23 WTGU's accounting procedures utilize integrated computerized business systems

1 to efficiently process, record and maintain transactions generated in the regular
2 course of business. Financial transactions are created and entered into the system
3 at or near the time of the transactions by personnel having personal knowledge of
4 the transactions, as well as of the applicable accounting procedure requirements.

5 **Q. AS A REGULATORY ACCOUNTANT, HOW DO YOU ASSURE**
6 **YOURSELF THAT TRANSACTIONS ARE RECORDED PROPERLY?**

7 A. As the Company's regulatory accountant, I have personal knowledge of the
8 Company's business processes, accounting systems, and integrity of its financial
9 reporting. The organization is staffed with qualified accounting personnel. WTGU
10 has established and maintained controls that ensure the accuracy of its books and
11 records. These controls help identify any necessary adjustments to accounting
12 entries, which are then recorded to the original books and records. Additionally,
13 WTGU engages the Whitley Penn LLP CPA accounting firm to perform an annual
14 audit of the Company's books to help ensure the continued integrity of WTGU's
15 financial reporting to customers, vendors, regulatory authorities, and others.

16 **Q. ARE THE COSTS RECORDED ON WTGU'S BOOKS AND RECORDS**
17 **SUPPORTED BY UNDERLYING INVOICES OR OTHER RECORDS?**

18 A. Yes. In order for a cost to be recorded in WTGU's general ledger, there must be a
19 vendor invoice, or other underlying documentation, that has been properly
20 approved or authorized, to support the entries recorded on WTGU's books.
21 Examples of other documentation include timesheets, contracts, leases, or other
22 agreements.

1 **Q. ARE WTGU'S BOOKS AND RECORDS MAINTAINED IN A MANNER BY**
2 **WHICH REVENUES, EXPENSES AND CAPITAL INVESTMENTS OF**
3 **THE VARIOUS LOCATIONS CAN BE IDENTIFIED?**

4 A. Yes, WTGU's books and records are generally maintained for each field (district)
5 office in order to identify revenues, expenses, and capital expenditures by location.
6 To accomplish this, WTGU has set up a unique entity ID number for each district
7 location.

8 **Q. DURING THE TEST YEAR, DID THE COMPANY HAVE IN PLACE ANY**
9 **PROCESS OR SYSTEM FOR THE REVIEW AND VALIDATION OF**
10 **INVOICES?**

11 A. All invoices for WTGU are scanned and processed through our Docuphase
12 software. Invoices are either sent to our Post Office Box, e-mailed to our accounts
13 payable e-mail address, or scanned by an accounts payable clerk in this office.
14 Once scanned, an electronic copy of the invoice is dispatched to a district manager
15 for approval. Invoices over certain amounts require approval from senior
16 employees or management with increasing levels of responsibility. After the
17 invoice is approved, the district clerk or the accountant codes the invoice. The
18 accountant is then responsible for reviewing the invoice to ensure it is properly
19 coded before payment is made.

20 **Q. PLEASE DESCRIBE THE PROCESS USED TO TEST INTERNAL**
21 **CONTROLS.**

22 A. Internal controls are reviewed annually for effectiveness by WTGU's independent
23 auditors. Upon the completion of the audit, the auditors provide WTGU with an

1 “audit wrap up” report that identifies any weaknesses in internal controls and makes
2 specific recommendations to management for solutions, if needed.

3 **Q. CAN YOU SUMMARIZE THE PROCESS USED BY WHITLEY PENN LLP**
4 **CPA TO PERFORM ITS AUDIT FUNCTION?**

5 A. Whitley Penn LLP CPA auditors utilize generally accepted auditing standards to
6 perform the annual audit of WTGU’s books and records. These auditing standards
7 establish a level of protocol the auditors must recognize during the performance of
8 their field work and the reporting of their finished work. The auditing standards
9 used by Whitley Penn LLP CPA are as follows:

10 **A. Standards of Field Work**

- 11 1. The auditor must adequately plan the work and must properly supervise any
12 assistants.
- 13 2. The auditor must obtain a sufficient understanding of the entity and its
14 environment, including its internal control, to assess the risk of material
15 misstatement of the financial statements whether due to error or fraud, and
16 to design the nature, timing, and extent of further audit procedures.
- 17 3. The auditor must obtain sufficient appropriate audit evidence by performing
18 audit procedures to afford a reasonable basis for an opinion regarding the
19 financial statements under audit.

20 **B. Standards of Reporting**

- 21 1. The auditor must state in the auditor’s report whether the financial
22 statements are presented in accordance with generally accepted accounting
23 principles.

- 1 2. The auditor must identify in the auditor's report those circumstances in
2 which such principles have not been consistently observed in the current
3 period in relation to the preceding period.
- 4 3. When the auditor determines that informative disclosures are not reasonably
5 adequate, the auditor must so state in the auditor's report.
- 6 4. The auditor must either express an opinion regarding the financial
7 statements, taken as a whole, or state that an opinion cannot be expressed,
8 in the auditor's report. When the auditor cannot express an overall opinion,
9 the auditor should state the reasons therefore in the auditor's report. In all
10 cases where an auditor's name is associated with financial statements, the
11 auditor should clearly indicate the character of the auditor's work, if any,
12 and the degree of responsibility the auditor is taking, in the auditor's report.
- 13 **Q. HOW DOES THE ACCOUNTING SYSTEM ALLOW FOR THE**
14 **SEPARATE RECORDING AND TRACKING OF COSTS FOR WTGU'S**
15 **UTILITY DISTRICTS?**
- 16 A. WTGU's accounting books and records are maintained separately and apart from
17 its subsidiaries. Within this accounting system, revenues and expenses must be
18 identified to a specific individual profit center (i.e., WTGU's home office or district
19 office). This identification process allows WTGU to create accounting reports for
20 each profit center.

1 **Q. WERE THE BOOKS AND RECORDS OF THE COMPANY PROVIDED TO**
2 **COMPANY WITNESSES FOR UTILIZATION IN THEIR ANALYSIS FOR**
3 **RATEMAKING PURPOSES?**

4 A. Yes.

5 **Q. DO THE AMOUNTS SHOWN IN THE RATE MODEL THAT ARE**
6 **IDENTIFIED AS “PER BOOKS” ACCURATELY REFLECT THE**
7 **COMPANY’S BOOKS?**

8 A. Yes.

9 **Q. WHAT STEPS DID WTGU TAKE TO ASSURE CONSISTENCY**
10 **BETWEEN THE COMPANY’S BOOKS AND RECORDS AND THE RATE**
11 **MODEL?**

12 A. Upon completion of the rate model, all schedules containing “Per Book” balances
13 were compared directly to WTGU’s Balance Sheet on December 31, 2023 and
14 WTGU’s Income Statement for the twelve-month test period ending December 31,
15 2023. Any differences between the rate model and WTGU’s trial balance were
16 discussed with the consultants for correction or reference, as applicable.

17 **Q. PLEASE DESCRIBE SCHEDULES THAT YOU SPONSOR OR CO-**
18 **SPONSOR.**

19 A. I co-sponsor Schedule B-1 (Operations and Maintenance Expense) with Messrs.
20 Smith, Fairchild and King and co-sponsor Schedule B-2 (Administrative and
21 General Expenses) with Messrs. Fairchild and King. Schedule B-1 presents
22 WTGU’s O&M expense by month for the test-year inclusive of adjustments.
23 Schedule B-2 presents WTGU’s A&G expense for the test-year inclusive of

1 adjustments. I co-sponsor Schedule C-5 (Gas Reliability Infrastructure Program
2 Additions) with Mr. Smith. Schedule C-5 presents all of the investment and capital
3 projects subject to a prudence review in this proceeding. I co-sponsor schedules H-
4 1 (Payroll Summary), H-2 (Payroll Analysis), H-3 (Bad Debts), H-4 (Advertising
5 Expenses), H-5 (Donations and Contributions), H-6 (Lobbying Expenses), H-7
6 (Penalties and Fines), H-8 (Outside Services Charged to A&G Accounts), H-9
7 (Legal Expense Detail), H-10 (Lost and Unaccounted for Gas), I-1 (Organizational
8 Chart), I-2 (Charges by Affiliates to WTGU), and I-3 (Charges by Affiliates to
9 Others) with Mr. King. Schedules H-1 through I-3 present various aspects of the
10 Company's test-year cost of service, confirm that the Company made adjustments
11 to the filing to comply with Commission rules, and support affiliate expenses
12 included in the filing.

13 **IV. COMPLIANCE WITH COMMISSION RULES AND NOTICES**

14 **Q. PLEASE DISCUSS THE SYSTEM OF ACCOUNTS THAT THE**
15 **COMPANY UTILIZES.**

16 A. WTGU has set up a cross reference of its general ledger chart of accounts with the
17 USOA. For regulatory reporting purposes, general ledger balances are entered into
18 an excel spreadsheet, which includes both sets of account numbers. This allows
19 WTGU to do regulatory reporting as needed using the USOA and still tie balances
20 back to its general ledger.

21 **Q DO THE BOOKS AND RECORDS, AS WELL AS THE SUMMARIES AND**
22 **EXCERPTS THEREFROM, QUALIFY FOR THE PRESUMPTION SET**
23 **FORTH IN THE COMMISSION'S RULE § 7.503?**

24 A. Yes. Because the Company maintains its books and records in accordance with

1 Commission Rule § 7.310, the amounts referenced on its books and records, as well
2 as summaries and excerpts from those books and records, are presumed to be
3 reasonable and necessary under the provisions of Rule § 7.503.

4 **Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION'S OTHER**
5 **RULES THAT RELATE TO COST OF SERVICE FILINGS IN**
6 **PRESENTING ITS REQUEST IN THIS CASE?**

7 A. Yes. The Company has complied with all of the Commission's rules related to cost
8 of service filings. For instance, Commission Rule § 7.501 requires a gas utility in
9 a rate proceeding to present evidence related to certain types of costs and
10 transactions. These costs include lobbying and legislative advocacy expenses,
11 business gifts, entertainment, charitable or civic contributions, and certain
12 advertising expenses. Consistent with Commission Rule § 7.501, these items have
13 been identified and excluded from the filing pursuant to Commission
14 Rule § 7.5414.

15 Commission Rule § 7.5252 also requires a gas utility in a rate proceeding
16 to book depreciation and amortization on a straight-line basis over the useful life
17 expectancy of the property or facility in question. Items of plant, revenues,
18 expenses, taxes, or reserves that are shared or common to the service area are to be
19 allocated to apportion them fairly and justly among the divisions of the utility.
20 Company witness Dane Watson addresses WTGU's requested depreciation and
21 amortization treatment. Additionally, Commission Rule § 7.5252 requires the
22 exclusion of nonutility amounts from the Company's cost of service.

1 Commission Rule § 7.5414 states that actual expenditures for advertising
2 will be allowed as a cost of service item for ratemaking purposes provided that the
3 total sum of such expenditures does not exceed one-half of 1% of the gross receipts
4 of the utility for utility services rendered to the public. Consistent with this
5 requirement, the Company has included only \$21,153 in the requested cost of
6 service for advertising during the test year. This amount is 0.0153% of the gross
7 receipts of the utility for utility services rendered to the public.

8 **Q. DOES RULE § 7.5414 PROHIBIT CERTAIN EXPENDITURES FROM**
9 **BEING INCLUDED IN THE COST OF SERVICE?**

10 A. Yes. Commission Rule § 7.5414 states that no expenditures shall be allowed as a
11 cost of service for ratemaking purposes if spent for the purpose of influencing
12 public opinion with respect to legislative, administrative, or electoral matters, or
13 with respect to any controversial issue of public importance. Additionally,
14 Commission Rule § 7.5414 excludes from the cost of service funds expended in
15 support of, or membership in, social, recreational, fraternal, or religious clubs or
16 organizations, and funds expended for contributions and donations to charitable,
17 religious, or other nonprofit organizations or institutions.

18 **Q. DID THE COMPANY MAKE ANY ADJUSTMENTS IN ACCORDANCE**
19 **WITH COMMISSION RULE § 7.5414?**

20 A. Yes. The Company decreased its test year expense by \$10,219 for expenses related
21 to legislative activities as shown on Schedule B-2.

1 **Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO TEST YEAR**
2 **EXPENSES RELATED TO MEALS, ENTERTAINMENT, LODGING, AND**
3 **TRAVEL EXPENSES?**

4 A. Yes. The Company is not seeking recovery of expenses related to meals,
5 entertainment, hotels, or travel expenses. The adjustment related to this reduction
6 to test year expense is shown on Schedule B-2.

7 **Q. HAS THE COMPANY INCLUDED ANY PROHIBITED EXPENDITURES**
8 **IN ITS COST OF SERVICE?**

9 A. No.

10 **Q. ARE YOU FAMILIAR WITH THE REQUIREMENTS OF COMMISSION**
11 **RULE § 7.5530?**

12 A. Yes. Commission Rule § 7.5530 states that in any rate proceeding, any utility
13 and/or municipality claiming reimbursement for its rate case expenses pursuant to
14 Gas Utility Regulatory Act (“GURA”) § 103.022, shall have the burden to prove
15 the reasonableness of such rate case expenses by a preponderance of the evidence.
16 Consistent with Rule § 7.5530, the Company will provide support for all reasonable
17 rate case expenses requested for reimbursement when such expenses are known.

18 **Q. ARE WTGU’S BOOKS AND RECORDS AVAILABLE FOR REVIEW?**

19 A. Yes. The Company’s books and records are available to a party for review at the
20 Company’s offices in Midland, Texas. Confidential information will be made
21 available to those qualified individuals who have executed a confidentiality
22 agreement.

1 **Q. ARE THERE ANY COMMISSION NOTICES WTGU HAS COMPLIED**
2 **WITH THAT RESULT IN COSTS IT SEEKS TO RECOVER IN THIS**
3 **CASE?**

4 A. Yes. The Company complied with the Notice of Authorization for Regulatory
5 Asset Accounting for Local Distribution Companies Affected by the February 2021
6 Winter Weather Event issued in February 2021 (“Uri Notice”). I address Winter
7 Storm Uri costs recorded to a regulatory asset in more detail below.

8 **V. TEST YEAR, PRUDENCE OF CAPITAL SPEND AND**
9 **COMPLIANCE WITH COMMISSION ORDERS**

10 **Q. WHAT IS THE TEST YEAR IN THIS CASE?**

11 A. The test year in this case is January 1, 2023 through December 31, 2023.

12 **Q. IS THE COMPANY SEEKING ANY PRUDENCE DETERMINATIONS**
13 **RELATED TO PLANT IN SERVICE?**

14 A. Yes, the Company is seeking a prudence determination for all capital investment
15 made in the WTGU system since rates were last approved in Docket No. OS-20-
16 00004347 through December 31, 2023. Attached to my testimony as Exhibit AE-
17 3 are the capital expense reports included in each of the Company Gas Reliability
18 Infrastructure Program (“GRIP”) filings since Docket No. OS-20-00004347. The
19 exhibit includes the capital expense reports the Company provided with the GRIP
20 filing it made on May 17, 2024, which addresses projects placed in service during
21 the test year, January 1, 2023 through December 31, 2023. As the preparer of the
22 Company’s annual GRIP filings, I sponsor the reports, while Mr. King and
23 Mr. Smith support the reasonableness, necessity, and prudence of the investment.

1 **Q. IS THE COMPANY REQUESTING RECOVERY OF ANY PLANT**
2 **INVESTMENT MADE AFTER THE END OF THE TEST YEAR?**

3 A. No, the filing does not include any known and measurable adjustments for post-test
4 year plant.

5 **Q. HAS THE COMPANY BEEN REQUIRED TO COMPLY WITH ANY**
6 **COMMISSION ACCOUNTING ORDERS SINCE ITS LAST RATE CASE?**

7 A. Yes. The Company was ordered in GUD No. 10695 to account for the impact of
8 the Tax Cuts and Jobs Act of 2017. In accordance with the Commission's
9 accounting order in that docket, the Company made a filing under § 104.111 of
10 GURA that was docketed as GUD No. 10763 and continued to account for Excess
11 Deferred Income Tax ("EDIT") amounts. In the Company's last rate case, Docket
12 No. OS-20-00004347, the Commission ordered a one-time EDIT refund and that
13 the Company to continue to amortize the remaining EDIT liability through 2045 in
14 compliance with GUD No. 10695 and guidance from the Internal Revenue
15 Service.¹ The Company completed the one-time EDIT refund and confirmed the
16 refund through a compliance filing made on June 16, 2021 in Docket No. OS-20-
17 00004347. The company also continues to amortize the remaining EDIT liability.
18 In this proceeding, Dr. Fairchild addresses the treatment of EDIT amounts.

¹ *Statement of Intent of West Texas Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of Texas*, Docket No. OS-20-00004347 consol., Final Order at Finding of Fact ("FoF") Nos. 41-45 (Feb. 9, 2021).

1 **VI. JURISDICTIONAL FACTOR FOR GRIP FILINGS**

2 **Q. WHO ARE THE COMPANY’S JURISDICTIONAL CUSTOMERS?**

3 A. “Jurisdictional” is the term that the Company uses to refer to customers whose rates
4 are regulated under the Commission’s jurisdiction. These customers include
5 residential, commercial, public authority, and non-profit.

6 **Q. WHO ARE THE COMPANY’S NON-JURISDICTIONAL CUSTOMERS?**

7 A. The Company also serves customers whose rates are not under the jurisdiction of
8 the Commission. The customers include commercial, irrigation, and transport
9 customers who use gas for agricultural use.

10 **Q. WHAT JURISDICTIONAL FACTOR HAS WTGU BEEN USING IN GRIP**
11 **FILINGS?**

12 A. As required by the Commission’s final order in the last rate case, the Company has
13 applied a 36.75% allocation to jurisdictional customers, which the parties agreed
14 would be analyzed further in the Company’s next rate case.² The rationale for the
15 jurisdictional factor is that the jurisdictional customers should not pay for portions
16 of the Company’s gas system that are used to serve non-jurisdictional customers.
17 However, in practice, the jurisdictional factor has prevented the company from fully
18 recovering costs for portions of the gas system that are used exclusively or primarily
19 to serve jurisdictional customers.

² *Id.* at FoF No. 37.

1 **Q. IS WTGU PROPOSING TO CHANGE THE JURISDICTIONAL FACTOR**
2 **IN THIS CASE?**

3 A. Yes. The percentage was originally based on the results of the Class Cost of Service
4 Study (“CCOSS”) in prior rate cases. In the last rate case, the results of the CCOSS
5 indicated that 37.84% of investment should be allocated to jurisdictional
6 customers.³ The Company agreed at the time to use the 36.75% allocator in future
7 GRIP filings, with the caveat that the issue would be analyzed in the next rate case.
8 Thus, since the last rate case, the Company has been only recovering 36.75% of its
9 capital investment through GRIP even if that capital investment was made for the
10 sole benefit and service of jurisdictional customers.

11 In this case, WTGU proposes that 100% of capital investment and costs that
12 benefit only jurisdictional customers be recovered from jurisdictional customers.
13 By the same token, WTGU proposes that capital investment and costs that benefit
14 only non-jurisdictional should not be recovered from jurisdictional customers. For
15 investment that benefits both jurisdictional and non-jurisdictional customers,
16 WTGU proposes to recover those costs based on the results of Dr. Fairchild’s class
17 cost of service study in this proceeding. The results of that study demonstrate that
18 51.22% of those joint costs should be recovered from jurisdictional customers.
19 Accordingly, WTGU proposes that a 51.22% jurisdictional allocation factor should
20 be approved for use in future GRIP filings. Mr. Smith addresses examples of the
21 Company’s capital investment that fall in these categories in more detail in his

³ Docket No. OS-20-00004347, SOI Ex. G, Cost of Service Schedules at Tab “J COSS”.

1 direct testimony. Dr. Fairchild explains in detail his class cost of service study and
 2 the resulting jurisdictional allocation factor.

3 **Q. PLEASE EXPLAIN HOW THE FACTOR IS APPLIED IN THE**
 4 **COMPANY’S RECENT GRIP FILINGS.**

5 A. I rely on the schedules in the Commission’s Interim Rate Adjustment Application
 6 and have done so for several years. The jurisdictional factor is applied to the total
 7 Interim Rate Adjustment Amount that is calculated using the GRIP formula and
 8 appears on Schedule IRA-5, IRA Summary at Line No. 26:

Line No.	Description	As of 12/31/2022	Adjustments	Ref	As of 12/31/2023	Change in Investment
(a)	(b)	(c)	(d)	(e)	(f)	(g)
						= (f) - (c) + (d)
West Texas Gas Utility, LLC Interim Rate Adjustment Application 12 Month Period Ending December 31, 2023 Interim Rate Adjustment Summary						
11	11 Direct Utility Plant Investment	\$ 229,409,521	\$ -		\$ 243,939,609	\$ 14,530,088
12	12 Direct Accumulated Depreciation	68,844,665	-		74,140,293	5,295,627
13	13 Allocated Utility Plant Investment (If applicable)	477,117	-		434,623	(42,494)
14	14 Allocated Accumulated Depreciation (If applicable)	56,386	-		112,943	56,558
15	15 Miscellaneous Adjustments	(9,002,214)	-		(9,868,938)	(866,724)
16	16 Net Utility Plant Investment (Ln 11 - 12 + 13 - 14 + 15)	\$ 151,983,372	\$ -		\$ 160,252,058	\$ 8,268,686
18	Calculation of the Interim Rate Adjustment Amount - Texas Operations:					
19	19 Rate of Return					7.32%
20	20 Return					\$ 605,169
21	21 Depreciation Expense					299,620
22	22 Property-related Taxes (Ad Valorem)					131,060
23	23 Revenue-related Taxes and State Margin Tax					-
24	24 Federal Income Tax					123,198
25	25 Interim Rate Adjustment Amount (Sum of Ln 19 through Ln 24)					\$ 1,159,047
26	26 Percentage Jurisdictional (Per OS-20-00004347)					36.75%
28	28 Interim Rate Adjustment Jurisdictional Amount (Ln 25 times Ln 26)					\$ 425,950

9 **Q. WHAT ARE THE CONSEQUENCES OF APPLYING THE**
 10 **JURISDICTIONAL FACTOR IN THAT WAY?**

11 A. The 36.75% factor inaccurately reduces the Company’s recovery of capital
 12 investment that benefits only jurisdictional customers. Schedule IRA-12, Direct
 13 Additions Report, contains the list of projects included in the Company’s GRIP
 14 filing. One of the requirements in that schedule is to identify the Customer Class
 15 Benefited in Column H. For the projects classified as “Jurisdictional,” the

1 Company is able to confirm that the project benefits and the costs are caused by
 2 only jurisdictional customers. Yet, in Schedule IRA-5, where the overall
 3 incremental investment is calculated, the 36.75% jurisdictional factor is applied to
 4 all projects, including projects classified as Jurisdictional. The result is that the
 5 Company is not able to fully recover the cost of jurisdictional-only investment from
 6 jurisdictional customers through the statutory GRIP process.

7 **Q. CAN YOU ILLUSTRATE THIS WITH A RECENT WTGU GRIP FILING?**

8 A. Yes. Below is an excerpt from Schedule IRA-12, Direct Additions Report, that
 9 identifies many Distribution Integrity Management Program (“DIMP”) projects the
 10 Company completed in 2023 that benefited only jurisdictional customers.

50	1660268	DIMP	PO 90318 2023 DIMP KERMIT	376.0	12/31/23	KERMIT & ENVIRONS	Jurisdictional	1,111,088.84	TX	100.00%	1,111,088.84
51	1660269	DIMP	PO 90321 2023 DIMP VAN	376.0	12/31/23	VAN HORN & ENVIRONS	Jurisdictional	306,976.74	TX	100.00%	306,976.74
52	1660270	DIMP	PO 90322 2023 DIMP	376.0	12/31/23	TRANS PECOS AREA - RURAL	Jurisdictional	167,720.29	TX	100.00%	167,720.29
53	1660271	DIMP	PO 90325 2023 DIMP	376.0	12/31/23	JUNCTION & ENVIRONS	Jurisdictional	23,729.29	TX	100.00%	23,729.29
54	1660272	DIMP	PO 90328 2023 DIMP MENARD	376.0	12/31/23	MENARD & ENVIRONS	Jurisdictional	263,932.01	TX	100.00%	263,932.01
55	1660273	DIMP	PO 90327 2023 DIMP SONORA	376.0	12/31/23	SONORA & ENVIRONS	Jurisdictional	489,867.95	TX	100.00%	489,867.95
56	1660274	DIMP	PO 90328 2023 DIMP EDEN	376.0	12/31/23	EDEN & ENVIRONS	Jurisdictional	597,780.73	TX	100.00%	597,780.73
57	1660275	DIMP	PO 90329 2023 DIMP	376.0	12/31/23	CHRISTOVAL ENVIRONS	Jurisdictional	3,376.69	TX	100.00%	3,376.69
58	1660276	DIMP	PO 90332 2023 DIMP	376.0	12/31/23	CANADIAN & ENVIRONS	Jurisdictional	1,099,462.73	TX	100.00%	1,099,462.73
59	1660277	DIMP	PO 90333 2023 DIMP	376.0	12/31/23	WHEELER TX & ENVIRONS	Jurisdictional	742,078.17	TX	100.00%	742,078.17
60	1660278	DIMP	PO 90334 2023 DIMP	376.0	12/31/23	SHAMROCK & ENVIRONS	Jurisdictional	734,159.58	TX	100.00%	734,159.58
61	1660279	DIMP	PO 90335 2023 DIMP	376.0	12/31/23	HIGGINS & ENVIRONS	Jurisdictional	6,562.38	TX	100.00%	6,562.38
62	1660280	DIMP	PO 90336 2023 DIMP	376.0	12/31/23	DARROUZETT & ENVIRONS	Jurisdictional	6,299.88	TX	100.00%	6,299.88
63	1660281	DIMP	PO 90337 2023 DIMP	376.0	12/31/23	FOLLETT & ENVIRONS	Jurisdictional	448,219.71	TX	100.00%	448,219.71
64	1660282	DIMP	PO 90338 2023 DIMP MIAMI	376.0	12/31/23	MIAMI & ENVIRONS	Jurisdictional	72,438.11	TX	100.00%	72,438.11
65	1660283	DIMP	PO 90340 2023 DIMP	376.0	12/31/23	CANADIAN AREA TX - RURAL	Jurisdictional	49,773.52	TX	100.00%	49,773.52
66	1660284	DIMP	PO 90349 2023 DIMP	376.0	12/31/23	TEXLINE & ENVIRONS	Jurisdictional	26,747.06	TX	100.00%	26,747.06
67	1660288	DIMP	PO 90357 2023 DIMP	376.0	12/31/23	SOMERSET & ENVIRONS	Jurisdictional	1,441,222.97	TX	100.00%	1,441,222.97
68	1660289	DIMP	PO 90358 2023 DIMP DEVINE	376.0	12/31/23	DEVINE & ENVIRONS	Jurisdictional	8,923.34	TX	100.00%	8,923.34
69	1660290	DIMP	PO 90359 2023 DIMP LA	376.0	12/31/23	LA PRYOR	Jurisdictional	117,319.36	TX	100.00%	117,319.36
70	1660291	DIMP	PO 90360 2023 DIMP	376.0	12/31/23	NATALIA & ENVIRONS	Jurisdictional	26,401.79	TX	100.00%	26,401.79
71	1660292	DIMP	PO 90361 2023 DIMP SAN	376.0	12/31/23	SAN ANTONIO AREA - RURAL	Jurisdictional	11,897.79	TX	100.00%	11,897.79

11 However, the 36.75% jurisdictional allocator is later applied to these investment
 12 amounts, which significantly reduces the total investment WTGU is able to recover
 13 from jurisdictional customers. For these reasons, the Company is requesting that it
 14 be able to fully recover from jurisdictional customers the full cost of the
 15 investments the Company makes to provide service to those customers. As
 16 calculated by Dr. Fairchild, the jurisdictional factor for GRIP filings going forward
 17 should be 51.22%. Crucially, the Company requests that this jurisdictional
 18 allocation factor should be applied only when investment benefits both

1 jurisdictional and non-jurisdictional customers. It should not apply to investment
2 that the Company can identify as purely for the benefit of jurisdictional customers.

3 **Q. HOW IS THE COMPANY ABLE TO DETERMINE THAT SOME**
4 **CAPITAL INVESTMENT BENEFITS ONLY JURISDICTIONAL**
5 **CUSTOMERS?**

6 A. The Company is able to identify certain capital investment that only jurisdictional
7 customers benefit from, such as new residential subdivision projects, maintenance
8 pipeline projects, as well as meters and measurement equipment. If a pipeline is
9 built for a new residential development, then the Company can confidently
10 determine that the new capital investment only benefits jurisdictional customers.
11 DIMP projects also only benefit jurisdictional customers because they improve the
12 safety, reliability, and integrity of the natural gas distribution systems that serve
13 regulated customers. These projects target the infrastructure within the Company's
14 regulated service areas such as residential neighborhoods in incorporated cities and
15 related environs. This ensures that the investment benefits are localized to the
16 customers whose rates are regulated through approved tariffs.

17 **Q. DOES THE JURISDICTIONAL FACTOR AFFECT WHAT GROWTH**
18 **AND BUSINESS OPPORTUNITIES THE COMPANY CAN VIABLY**
19 **PURSUE?**

20 A. Yes. Because the Company's GRIP formula is hampered by the jurisdictional
21 factor, it cannot always build or invest in potential distribution systems that a
22 competitor might determine are economically viable because the competitor could
23 fully and expeditiously start recovering that capital investment through GRIP while

1 the Company cannot. Likewise, when the Company considers whether to acquire
2 older or distressed gas distribution systems and rehabilitate and incorporate those
3 systems into the Company’s system, the Company must consider that full recovery
4 of those capital investment activities would not be possible under the current GRIP
5 formula.

6 **VII. SHARED SERVICES**

7 **Q. WHAT IS WTG DOWNSTREAM SERVICES, LLC?**

8 A. WTGDS provides corporate support services to WTGU and various allocation
9 methods as set out in its Cost Allocation Manual (“CAM”), attached as Exhibit AE-
10 2, are used to transfer these expenses recorded on the books of the Company to the
11 appropriate entity or entities. Its predecessor entity, JLD Shared Services, LLC was
12 established in consultation with Commission Staff following the Company’s 2013
13 rate case to provide a means to assign, allocate, record and pay certain employee
14 earnings and various vendor expenditures that directly and/or indirectly benefit
15 some or all of the WTG entities, including WTGU.

16 **Q. WHAT CORPORATE SUPPORT SERVICES DOES WTGDS PROVIDE?**

17 A. The support functions include but are not limited to accounting, information
18 technology, communications infrastructure, human resource management
19 (including payroll and benefit plans), insurance services, financial services, general
20 administrative, regulatory compliance, environmental and land services,
21 purchasing services, office infrastructure (including leasehold space and utilities),
22 and professional services (including, but not limited to legal, accounting,
23 engineering, and other consulting services).

1 **Q. WHAT BENEFITS ARE PROVIDED THROUGH A CENTRALIZED**
 2 **CORPORATE SUPPORT SERVICES STRUCTURE?**

3 A. A centralized Corporate Support Services structure allows all WTG entities,
 4 including the Company, to leverage resources across multiple business units,
 5 thereby giving the business units access to specialized skills and resources in an
 6 efficient and cost-effective manner. For example, accounting for employee benefits
 7 requires skilled and experienced individuals who must be able to analyze
 8 accounting standards related to employee benefits, understand the components of
 9 the benefit programs, and have the ability to discuss the benefit programs with
 10 actuaries. Having a centralized function eliminates the need for each of the
 11 business units to have that expertise separately, thus eliminating the need for
 12 duplication.

13 **Q. HOW MUCH O&M EXPENSE DID EACH OF THE SERVICE COMPANY**
 14 **FUNCTIONS CHARGE WTGU IN THE TEST YEAR?**

15 A. The table below shows WTGDS’s costs and the amounts billed to WTGU for each
 16 of the functional areas in the test year:

Service Company Functional Area	For the Test Year End December 31, 2023	
	Total Billings (Thousand)	WTGU Billings (Thousand)*
Labor and Related Personnel Costs	45,081	11,343
Insurance Expense	13,363	908
Electricity	8,172	21
Overhead Burden	11,153	967
P-Card Purchases	1,055	394
Phone Expense	1,615	226
Other	10,025	339
Total WTGDS	90,463	14,198

1 **Q. ARE THE AMOUNTS ASSIGNED TO WTGU AND OTHER AFFILIATES**
2 **COST-BASED?**

3 A. Yes. WTGDS bills all expenses at cost.

4 **Q. ARE THE METHODS USED BY WTGDS TO BILL ALL AFFILIATES,**
5 **INCLUDING WTGU, THE SAME?**

6 A. Yes. All costs for a given service that are directly related to affiliates, including
7 WTGU, are directly billed. If allocated, the costs are not higher than the prices
8 charged by WTGDS for the same class of items to other affiliates.

9 **Q. WHAT TYPE OF INFORMATION IS FOUND IN THE CAM?**

10 A. The CAM documents the billing methodology used by WTGDS and details the
11 major activities performed by the cost center and the cost assignment method for
12 the cost center.

13 **Q. IS AN ASSIGNMENT METHOD IDENTIFIED FOR EACH SERVICE**
14 **COMPANY FUNCTION?**

15 A. Yes. Each function is reviewed following guidelines outlined in the CAM to
16 determine the proper method to assign costs to the cost centers within the function.
17 The CAM outlines the allocation method for each WTGDS cost center.

18 **Q. DOES THE COMPANY'S REQUEST FOR WTGDS EXPENSE MEET THE**
19 **STATUTORY AFFILIATE STANDARD IN GURA § 104.055?**

20 A. Yes. All affiliate costs included in this filing are reasonable and necessary costs of
21 providing gas utility service, and the prices charged to WTGU are no higher than
22 the prices charged by the supplying affiliate to other affiliates or to a non-affiliated

1 person for the same item or class of items. Corporate costs are directly billed where
2 possible, or allocated pursuant to the CAM where direct assignment is impractical.

3 **VIII. WINTER STORM URI REGULATORY ASSET**

4 **Q. DID THE COMMISSION ISSUE ANY GUIDANCE RELATED TO**
5 **EXTRAORDINARY EXPENSES A GAS UTILITY MIGHT HAVE TO**
6 **INCUR DURING WINTER STORM URI?**

7 A. Yes. The Commission issued a Notice on February 13, 2021, to Local Distribution
8 Companies (“LDCs”) authorizing LDCs to create a regulatory asset to record
9 “extraordinary” costs incurred during Winter Storm Uri (“Regulatory Asset
10 Notice”). In the Regulatory Asset Notice, the Commission acknowledged gas
11 utilities may have to pay high prices for natural gas given the demand for gas during
12 Winter Storm Uri and the Commission encouraged LDCs to ensure customers were
13 provided with safe and reliable natural gas service.

14 Later, on June 17, 2021, the Commission issued another notice that
15 explained the process LDCs could follow to determine and recover regulatory asset
16 amounts and participate in a securitization process the legislature enacted following
17 Winter Storm Uri. Even though WTGU did not participate in securitization, the
18 notice the Commission issued in June 2021 identifies some of the information and
19 documentation the Commission wanted to review to analyze extraordinary costs,
20 and the Company is providing that type of information in this case.

1 **Q. WHAT ACTIONS DID WTGU TAKE IN RESPONSE TO THE**
2 **REGULATORY ASSET NOTICE?**

3 A. Based on the Regulatory Asset Notice, WTGU created a regulatory asset on its
4 books to book extraordinary costs the Company incurred to provide service to
5 customers during the storm.

6 **Q. PLEASE IDENTIFY THE COSTS IN THE REGULATORY ASSET.**

7 A. WTGU's regulatory asset consists of \$3,502,862.85 in extraordinary gas costs.
8 WTGU is not requesting the carrying costs associated with this regulatory asset.

9 **Q. HOW DID THE COMPANY CALCULATE THE AMOUNT OF**
10 **EXTRAORDINARY GAS COSTS?**

11 A. The process used to determine the extraordinary gas costs was to calculate the
12 average daily gas price for February 2021 without the winter price dates included.
13 This price was then multiplied by the volume to get a normalized gas cost. The
14 remaining amount of the invoice was then recorded in the regulatory asset account
15 as extraordinary gas costs. This calculation is addressed further in Mr. King's
16 testimony.

17 More broadly, the regulatory asset account was for costs that were directly
18 associated with the Company's response to Winter Storm Uri and would not have
19 been incurred but for the winter storm. The Company did not use the asset for
20 expenses that would be expected under normal or typical operating conditions such
21 as regular labor, normal contractor costs, or capital projects.

1 **Q. WHAT PROCESS DID THE COMPANY FOLLOW TO VERIFY THE**
2 **ACCURACY OF THE GAS COST INVOICES IT RECEIVED FOR GAS**
3 **PURCHASED AND DELIVERED TO CUSTOMERS DURING THE**
4 **WINTER STORM?**

5 A. The Company had several steps to verify the accuracy of the gas cost invoices it
6 received for gas purchased and delivered to customers during the winter storm.
7 Both volumes and prices were verified for each gas cost invoice. The prices were
8 verified against published first of month indexes and gas daily indexes, and the
9 volumes were verified against volume statements. These are reviewed by both the
10 gas supply manager and the VP of Gas Marketing.

11 **Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO AMOUNTS**
12 **INCLUDED IN THE REGULATORY ASSET?**

13 A. No.

14 **Q. DO THE EXTRAORDINARY GAS COSTS INCLUDE AFFILIATE**
15 **EXPENSES?**

16 A. Yes. As explained in detail by Mr. King, WTGU obtains gas supply through its
17 affiliate gas, WTG Gas Marketing, LLC (“WTGGM”). Mr. King also explains how
18 the extraordinary gas costs included in the regulatory asset are reasonable and
19 necessary costs of providing gas utility service, and the prices charged to WTGU
20 are no higher than the prices charged by WTGGM to other affiliates or to non-
21 affiliated persons.

22 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

23 A. Yes, it does.

STATE OF TEXAS §
 §
COUNTY OF MIDLAND §

AFFIDAVIT OF AMANDA EDGMON

BEFORE ME, the undersigned authority, on this day personally appeared Amanda Edgmon, who having been placed under oath by me did depose as follows:

1. “My name is Amanda Edgmon. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is Treasurer and Secretary and Regulatory Accountant for West Texas Gas Utility, LLC.
2. I have prepared the foregoing direct testimony and the information contained in this document is true and correct to the best of my knowledge.”

Further affiant sayeth not.

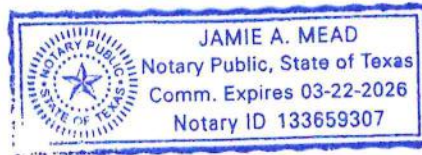


Amanda Edgmon

SUBSCRIBED AND SWORN TO BEFORE ME by the said Amanda Edgmon on this 27th day of June 2024.



Notary Public, State of Texas



GL ACCT	DESCRIPTION	FERC ACCT
725-005	MUNICIPAL DOMESTIC GAS SALES	480.0
725-010	RURAL DOMESTIC GAS SALES	480.0
725-015	GAS SALES-PUBLIC AUTH CITY	482.0
725-016	GAS SALES-PUBLIC AUTH RURAL	482.0
725-020	GAS SALES-INTERSTATE	483.0
725-025	SMALL COMM & IND	481.0
725-030	RURAL SMALL COMM & IND	481.0
725-035	LARGE COMM & IND	481.0
725-040	RURAL LARGE COMM & IND	481.0
725-045	IRRIGATION SALES	481.0
725-055	SALES FOR RESALE	483.0
725-058	LEAKAGE ALLOCATION REVENUE	481.0
725-075	SERVICE CHARGES	488.0
725-085	GAS TRANSPORTATION FEES	489.3
725-090	CONNECTION FEES	488.0
725-095	METER REPAIR - LABOR	488.0
725-100	SALES-REGULATORS,ETC	488.0
725-110	OTHER INCOME	495.0
725-115	RETURNED CHECK CHARGE	488.0
725-140	DRIP & CONDENSATE SALES	492.0
725-150	GAS GATHERING FEES	489.1
725-160	MISC TARIFF FEES	488.0
725-165	COLLECTION FEES	488.0
725-170	OVER/UNDER GAS COST REVENUES	807.0
725-200	INTERCOMPANY SALES/RECEIPTS	484.0
765-005	INTEREST INCOME NON-AFFILIATE	419.0
770-040	RENTAL INCOME	418.0
780-015	MISCELLANEOUS	421.0
780-100	EMPLOYEE FEE/OTHER REIMB	421.0
780-200	HEDGING GAINS/LOSSES	807.5
780-400	MARKED TO MARKET GAINS/LOSSES	807.5
800-005	TRANSMISSION LINE PURCHASES	803.0
800-015	GAS WELL GAS	800.0
800-025	GATHERING FEE	858.0
800-035	TRANSPORTATION FEE	858.0
800-150	ODORANT	874.0
800-155	COST OF PART SALES	813.0
800-175	COMPANY USE	812.0
900-005	OFFICE PAYROLL - SALARIED	920.0
900-010	OFFICE PAYROLL - HOURLY	920.0
900-016	OFFICE PAYROLL - OVERTIME	920.0
900-021	NON-CASH EMPLOYEE COMP	920.0
900-023	PROF SERV-COLLECTIONS	923.0
900-025	PROF SERV-LEGAL	923.0
900-030	PROF SERV-ACCTG	923.0
900-045	PROF SERV-OTHER	923.0

900-050	OVERHEAD BURDEN	923.0
900-055	CONTRACT LABOR	923.0
900-056	SECRETARIAL SERVICE	923.0
900-065	OFFICE SUPPLIES & EXPENSE	921.0
900-080	POSTAGE & FREIGHT	921.0
900-086	BOTTLED WATER	921.0
900-095	JANITORIAL SUPPLIES	921.0
900-096	SMALL TOOLS	921.0
900-100	TELEPHONE	921.0
900-105	ANSWERING SERVICE	921.0
900-130	ELECTRIC UTILITY	921.0
900-140	PAYROLL TAXES	408.2
900-145	AD VALOREM TAX	408.2
900-150	FRANCHISE TAX	408.2
900-160	OTHER TAXES	408.2
900-164	PART 192 COMPLIANCE - GENERAL	930.2
900-165	FILING FEES	930.2
900-166	DOT PIPELINE SAFETY USER FEE	930.2
900-167	PUBLIC AWARENESS	910.0
900-168	INTEGRITY MGMT TRANSMISSION	874.0
900-169	OPERATOR QUALIFICATIONS	874.0
900-170	LICENSES & PERMITS	930.2
900-171	UNIFORMS	874.0
900-175	INSURANCE-GROUP & PAYROLL	926.0
900-180	INSURANCE-OTHER	924.0
900-181	WORKMAN'S COMP CLAIMS PAID	926.0
900-185	PENSION PLAN	926.0
900-190	EMPLOYEE BENEFITS	926.0
900-195	EMPLOYEE EDUCATION	926.0
900-198	EMP PHYSCLS/ALCOHOL DRUG TESTS	926.0
900-205	AUTO OIL & GAS	930.2
900-215	EMPLOYEE EXPENSE - OTHER	930.2
900-221	LODGING	930.2
900-225	PILOT TIME	930.2
900-231	RENTAL FEES	931.0
900-240	OFFICE EQUIPMENT LEASE	931.0
900-250	STORAGE	931.0
900-255	SERVICE CHARGES	930.2
900-260	DUES & SUBSCRIPTIONS	930.2
900-265	DONATIONS	930.2
900-275	ENTERTAINMENT & MEALS	921.0
900-276	TRAVEL	921.0
900-290	PENALTIES, FINES, ETC	921.0
900-315	COMPUTER SOFTWARE - RENT	921.0
900-320	COMPUTER PAPER & FORMS	921.0
900-340	MAINTENANCE SUPPLIES	930.2
900-345	COMPUTER INTERNET SERVICE	921.0

900-350	COMPUTER SOFTWARE SUPPORT	921.0
900-370	CAPITALIZED OVERHEAD	920.0
900-382	SAFETY COMPLIANCE	926.0
900-400	RESALE EXPENSES - REBILLABLE	930.2
900-900	MISCELLANEOUS	930.2
915-010	OFFICE PAYROLL - HOURLY	870.0
915-015	FIELD PAYROLL - SALARIED	870.0
915-021	FIELD PAYROLL - OVERTIME	870.0
915-030	CONTR LBR-BCKHOE & DITCHG	874.0
915-035	CONTR LBR-WELDING	874.0
915-040	CONTRACT LBR-PUMPERS	874.0
915-045	CONTR LBR-MANUAL LABOR	874.0
915-050	CONTR LBR-OTHER	874.0
915-055	CONSULTING	874.0
915-059	PROF SERV-COLLECTIONS	874.0
915-060	PROF SERV-LEGAL	874.0
915-063	PROF SERV-OTHER	874.0
915-075	OFFICE SUPPLIES	880.0
915-076	MARKETING FEE	913.0
915-080	MAPS, XEROX, PRINTING	880.0
915-085	POSTAGE & FREIGHT	880.0
915-090	COFFEE BAR	880.0
915-091	BOTTLED WATER	880.0
915-095	TELEPHONE	880.0
915-100	ELECTRICITY UTILITIES	880.0
915-105	WATER UTILITIES	880.0
915-110	GAS UTILITIES	880.0
915-111	CLEANING, EXTERMINATING	880.0
915-114	TRASH HAULING	880.0
915-115	UTILITIES - OTHER	880.0
915-120	RADIO & ALARM	880.0
915-150	MISC RECEIPTS TAX	408.2
915-156	LICENSES AND TITLES	880.0
915-157	AD VALOREM TAXES	408.2
915-158	FILING FEES	880.0
915-161	PAYROLL TAX	408.2
915-165	OFFICE RENT	881.0
915-170	RENTS-OTHER	881.0
915-171	RENTAL FEES	881.0
915-174	OTHER LEASE EXPENSE	881.0
915-175	EQUIPMENT RENTALS	881.0
915-180	STORAGE CHARGES	930.2
915-190	AUTO OIL & GAS	930.2
915-205	DUES & SUBSCRIPTIONS	880.0
915-210	DONATIONS	880.0
915-211	BENEVOLENCES	930.2
915-215	ADVERTISING	913.0

915-216	PROMOTION EXPENSE	913.0
915-220	ENTERTAINMENT & MEALS	930.2
915-221	LODGING	930.2
915-222	TRAVEL	930.2
915-225	CHART INTEGRATION	874.0
915-226	GAS ANALYSES	874.0
915-227	SCADA - MEASUREMENT EQUIP	874.0
915-230	SVC STA & WHSE SUPPLIES	874.0
915-235	FIELD SUPP-PIPE & FITTG	874.0
915-240	FIELD SUPP-MEASURE EQUIP	874.0
915-245	FIELD SUPP-TOOLS	874.0
915-250	FIELD SUPP-OTHERS	874.0
915-255	FIELD SUPP-ON TRUCKS	874.0
915-256	SAFETY SUPPLIES	874.0
915-260	UNIFORMS	880.0
915-262	WELDING SUPPLIES	874.0
915-268	ENGINE ANTIFREEZE	880.0
915-270	LUBRICANTS & OILS	880.0
915-275	METHANOL	874.0
915-276	LAUNDROMAT	880.0
915-280	PROPANE	880.0
915-288	PIPELINE CHEMICALS	880.0
915-291	DAMAGES	874.0
915-292	RIGHT OF WAY - EASEMENT	874.0
915-294	PIPELINE LEASE EXPENSE	874.0
915-295	WATER HAULING/DISPOSAL	874.0
915-302	METER TESTING	874.0
915-303	PIPELINE EXPENSE	874.0
915-305	DELAY RENTALS	874.0
915-320	LEAK DETECTION	874.0
915-335	SERVICE CHARGE	880.0
915-340	CASH OVER/SHORT	880.0
915-382	SAFETY COMPLIANCE	874.0
915-400	EMPLOYEE BENEFITS	926.0
915-410	EMP PHYSCLS/ALCOHOL-DRUG TESTS	926.0
915-420	EMPLOYEE EDUCATION	926.0
915-425	COMPUTER INTERNET SERVICE	880.0
915-900	MISC	880.0
920-002	BUILDINGS, CANOPIES, DRIVEWAYS	894.0
920-003	ROLLING STOCK	894.0
920-004	SIGNAGE	894.0
920-005	ROLLING STOCK/REP & MAINT	894.0
920-010	AUTO & PU REP &	894.0
920-020	REP & MAINT/PROPANE TANK	894.0
920-021	SHOP EQUIPMENT RECALIBRATION	894.0
920-030	REP & MAINT-DISTRIBUTION LINE	887.0
920-031	R & M - DISTRIBUTION	887.0

920-035	REP & MAINT TRANSMISSION LINE	863.0
920-040	REP & MAINT-METER,REGLTR	889.0
920-041	R & M - METERS	889.0
920-045	REP & MAINT-ODOR & SFTY	889.0
920-046	CATHODIC PROTECTION	894.0
920-055	GENERATOR MAINT	888.0
920-065	TANKS & VESSELS MAINT	888.0
920-070	FIELD MEASUR EQUIP MAINT	889.0
920-075	PIPES VALVES & FITTINGS MAINT	889.0
920-080	ELECTRICAL MAINT	889.0
920-082	TAP, METER MAINT	889.0
920-083	AIR COMPRESSOR REPAIR	889.0
920-084	GAS COMPRESSOR PREVENTIVE MAINT	888.0
920-085	COMPRESSOR ENGINE MAINT	888.0
920-090	INSTRUMENTS & CONTROLS MAINT	894.0
920-095	SITE MAINTENANCE	894.0
920-105	REP & MAINT-STRUC & IMPROV	886.0
920-110	GROUNDS & EQUIPMENT	894.0
920-115	PLUMBING	894.0
920-120	COMMUNICATION EQUIPMENT	894.0
920-125	REPAIRS - OFFICE EQUIPMENT	894.0
920-130	MISC MAINTENANCE EXPENSE	894.0
920-140	LOCKS & KEYS	894.0
920-145	DOORS & WINDOWS	894.0
920-150	HEATING & AIR CONDITIONING	894.0
920-160	FENCES & GATES	894.0
920-165	PAINT, WALLS & TILES	894.0
920-170	EXTERMINATING	894.0
920-175	CLEANING & SUPPLIES	894.0
930-005	INTEREST EXPENSE NON-AFFILIATE	427.0
930-010	DEPRECIATION	403.0
930-015	AMORTIZATION	404.3
930-045	BAD DEBT EXPENSE	904.0
930-060	AMORTIZATION CIAC	403.1

GL Acct	Description	FERC
100-100	PETTY CASH	135.0
100-220	CASH OPER-WELLS FARGO BANK	131.0
100-309	CASH DEP-TRANS PECOS AREA	131.0
100-317	CASH DEP-SHAMROCK DISTRICT	131.0
100-321	CASH DEP-DALHART DISTRICT	131.0
100-327	CASH DEP-PLAINVIEW (NG)	131.0
100-330	CASH DEP-JUNCTION AREA	131.0
100-335	CASH DEP-AMARILLO AREA	131.0
100-340	CASH DEP-CANADIAN AREA	131.0
100-350	CASH DEP-WHEELER DISTRICT	131.0
100-366	CASH DEP-SAN ANTONIO AREA	131.0
100-370	CASH DEP-GUYMON AREA	131.0
100-374	CASH DEP-STRATFORD DISTRICT	131.0
100-430	CASH DEP-LUBBOCK AREA	131.0
105-205	CERTIFICATES OF DEPOSITS	136.0
120-005	INSUFF CHECK RETURN	143.0
120-032	UNRECOVERED GAS COST - OKLA	191.0
120-032	UNRECOVERED GAS COST - OKLA	191.0
120-035	UNRECOVERED OKLA DEMAND CHGS	191.0
120-035	UNRECOVERED OKLA DEMAND CHGS	191.0
120-140	A/R TRADE - NATURAL GAS	142.0
120-145	A/R OTHERS	143.0
120-180	A/R RATE CASE EXPENSES	142.0
120-185	A/R PIPELINE SURCHARGE TX	142.0
120-186	A/R OCC PUB UTILITY SURCHARGE	142.0
120-195	A/R OCC LUFG SURCHARGE	142.0
120-215	A/R COVID-19 EXPENSES	182.3
120-220	2021 WINTER WEATHER EVENT	182.3
125-111	RESERVE FOR BAD DEBTS - NG	144.0
125-111	RESERVE FOR BAD DEBTS - NG	144.0
126-100	A/R AFFILIATE	146.0
126-141	A/R WTG GAS MARKETING	146.0
128-017	ICT A/R WTG LIQUIDS DIVISION	146.0
140-100	P/P INSURANCE EXPENSE	165.0
140-110	P/P EXPENSE OTHER	165.0
140-112	P/P NAT GAS CONTRACT WGI SYS	165.0
150-275	INVENTORY-OTHER	154.0
150-400	INVENTORY-EGW	154.0
160-900	SUSPENSE	174.0
235-010	PIPELINE	101.0
235-012	METERS AND REGULATORS	101.0
240-001	PIPELINE	101.0
240-005	METERS & REGULATORS	101.0
240-010	COMPRESSORS	101.0
240-015	RIGHT-OF-WAY	101.0
240-015	RIGHT-OF-WAY	101.0

240-020	TESTING EQUIPMENT	101.0
240-020	TESTING EQUIPMENT	101.0
240-025	FIELD TOOLS	101.0
240-030	GAS DIST FACIL. -OTHER	101.0
241-001	PIPELINE	101.0
241-001	PIPELINE	101.0
241-005	METERS & REGULATORS	101.0
241-010	COMPRESSORS	101.0
241-020	TESTING EQUIPMENT	101.0
241-020	TESTING EQUIPMENT	101.0
241-025	FIELD TOOLS	101.0
241-030	GAS DIST FACILITY OTHER	101.0
250-010	PIPELINE	101.0
250-010	PIPELINE	101.0
250-020	METERS & REGULATORS	101.0
250-030	COMPRESSOR STATION EQUIP	101.0
250-040	RIGHT-OF-WAY	101.0
250-040	RIGHT-OF-WAY	101.0
250-045	MEASURING & REG STA EQUIP	101.0
250-050	OTHER EQUIPMENT	101.0
250-065	MEASUR & REG STA STRUCTURES	101.0
270-005	AUTOMOBILES	101.0
270-006	HEAVY ROLLING STOCK	101.0
270-007	TRAILERS	101.0
270-007	TRAILERS	101.0
270-011	EXCAVA. & CONSTR EQUIP	101.0
270-020	COMMUNICATION EQUIPMENT	101.0
270-025	OFFICE FURNISHINGS & EQUIPMENT	101.0
270-030	MAINTENANCE EQUIPMENT	101.0
270-035	FIELD EQUIPMENT	101.0
270-045	OTHER	101.0
270-065	DATA PROCESSING EQUIP	101.0
270-101	CIP - DISTRIBUTION PIPELINE	107.0
270-105	CIP - DISTR METERS/REGULATORS	107.0
270-110	CIP - TRANSMISSION PIPELINE	107.0
270-125	CIP - ROW, EASEMENTS, DAMAGES	107.0
271-005	AUTOMOBILES	101.0
271-006	HEAVY ROLLING STOCK	101.0
271-025	OFFICE FURNITURE & EQUIP	101.0
271-035	FIELD EQUIPMENT	101.0
271-045	OTHER	101.0
275-005	BUILDINGS	101.0
275-010	FENCING	101.0
275-025	LAND	101.0
275-035	LEASEHOLD IMPROVEMENTS	101.0
275-040	SITE IMPROVEMENT	101.0
275-040	SITE IMPROVEMENT	101.0

276-005	BUILDINGS	101.0
276-025	LAND	101.0
276-040	SITE IMPROVEMENTS	101.0
276-040	SITE IMPROVEMENTS	101.0
280-005	ORGANIZATION COST	101.0
280-010	RIGHT-OF-WAY	101.0
280-010	RIGHT-OF-WAY	101.0
280-065	FRANCHISE COSTS	101.0
280-075	CAPITALIZED SOFTWARE	101.0
280-100	MISC OTHER INT NON-AMORTIZING	101.0
281-010	RIGHT-OF-WAY	101.0
281-010	RIGHT-OF-WAY	101.0
281-070	OTHER	101.0
335-005	GAS GATHERING SYSTEMS	108.0
335-010	PIPELINE / PIPE	108.0
335-010	PIPELINE / PIPE	108.0
340-001	PIPELINE	108.0
340-001	PIPELINE	108.0
340-005	METERS & REGULATORS	108.0
340-010	COMPRESSORS	108.0
340-015	RIGHT-OF-WAY	108.0
340-015	RIGHT-OF-WAY	108.0
340-020	TESTING EQUIPMENT	108.0
340-020	TESTING EQUIPMENT	108.0
341-001	PIPELINE	108.0
341-001	PIPELINE	108.0
341-005	METERS & REGULATORS	108.0
341-010	COMPRESSORS	108.0
341-020	TESTING EQUIPMENT	108.0
341-020	TESTING EQUIPMENT	108.0
350-010	PIPELINE	108.0
350-010	PIPELINE	108.0
350-020	METERS & REGULATORS	108.0
350-030	COMPRESSOR STATION EQUIP	108.0
350-040	RIGHT-OF-WAY	108.0
350-040	RIGHT-OF-WAY	108.0
350-050	OTHER	108.0
350-060	COMPRESSOR STATION STRUCTURES	108.0
370-005	AUTOMOBILES	108.0
370-010	STEAM CLEANER	108.0
370-010	STEAM CLEANER	108.0
370-020	COMMUNICATION EQUIPMENT	108.0
370-025	OFFICE FURNISHINGS & EQUIPMENT	108.0
370-040	PULLING UNITS	108.0
370-040	PULLING UNITS	108.0
371-005	AUTOMOBILES	108.0
371-025	OFFICE FURNITURE & EQUIP	108.0

371-035	FIELD EQUIPMENT	108.0
371-045	OTHER	108.0
375-005	BUILDINGS	108.0
376-005	BUILDINGS	108.0
380-005	ORGANIZATION COST	108.0
380-010	RIGHT-OF-WAY	108.0
380-010	RIGHT-OF-WAY	108.0
380-065	FRANCHISE COSTS	108.0
380-100	MISC OTHER INT NON-AMORTIZING	108.0
381-010	RIGHT-OF-WAY	108.0
381-010	RIGHT-OF-WAY	108.0
400-005	A/P TRADE	232.0
400-010	A/P OTHER	232.0
400-015	A/P OTHER NG PURCHASES	232.0
400-036	A/P TEXAS GAS USERS ASSOC	232.0
400-120	A/P CONTRACT GAS PAYABLE TW	232.0
405-005	A/P AFFILIATES	234.0
405-030	A/P WTGM COMMODITY	234.0
420-005	CUSTOMER DEPOSITS	235.0
425-010	ACCR MISC RECEIPTS TAX	236.0
425-015	ACCR TEXAS SALES TAX	236.0
425-036	ACCR OKLA COUNTY TAX	236.0
425-037	ACCR OKLA FRANCHISE FEE	236.0
425-045	ACCR TEXAS FRANCHISE TAX	236.0
425-055	ACCR TEXAS CITY TAX	236.0
425-056	ACCR TEXAS COUNTY TAX	236.0
430-010	WELLS FARGO BANK TEXAS, N.A.	237.0
430-100	ACCRUED INTEREST OTHER	237.0
435-015	ACCR EXPENSES-OTHER	242.0
435-033	UNRECOVERED GAS COST - TX	242.0
435-033	UNRECOVERED GAS COST - TX	242.0
450-105	DEFERRED LIABILITY CIAC	101.0
450-110	DEFERRED COST OF GAS	253.0
450-120	DEFERRED MARK TO MARKET LOSS	245.0
605-100	EQUITY DISTRIB PAID/RECEIVED	216.0
617-000	YTD INCOME	216.0
617-000	RETAINED EARNINGS	216.0
617-000	RETAINED EARNINGS	216.0
617-000	RETAINED EARNINGS	216.0
617-000	RETAINED EARNINGS	216.0
635-275	MEMBERS' EQUITY	216.0

WTG DOWNSTREAM SERVICES, LLC COST ALLOCATION MANUAL

Purpose

WTG Downstream Services, LLC (“WTGDS” or “Company”) has been established to provide a means to assign, allocate, record and pay certain employee earnings and various vendor expenditures that directly and/or indirectly benefit some or all of the WTG entities. Various allocation methods, as set out in this Cost Allocation Manual (“CAM”), are used to transfer these expenses recorded on the books of the Company to the appropriate entity or entities. This CAM is applicable to WTGDS only and does not reflect further allocation practices applied to the books and records of affiliated entities for regulatory, contractual or financial reporting purposes.

Corporate Structure

Appendix A is an organization chart depicting the wholly owned subsidiaries of WTG Downstream LLC (the “Downstream Subsidiaries”) and the wholly owned subsidiaries of WTG Downstream LLC’s sister holding companies, WTG Fuels Holdings LLC (the “Fuels Subsidiaries”) and WTG Midstream LLC (the “Midstream Subsidiaries”) which together with the Downstream Subsidiaries and the Fuels Subsidiaries are collectively, the “WTG Subsidiaries”). WTG Downstream Holdings LLC (“WTG Downstream”) is ultimately owned 80% by Stonepeak Remuda Investment Holdings LLC and 20% by the Estate of James Lee Davis, deceased. WTG Downstream Services, LLC (a wholly owned subsidiary of WTG Downstream) (“Downstream Services”) is the W-2 employer of all employees who work exclusively for the Downstream Subsidiaries or the Fuels Subsidiaries. WTG Midstream LLC is the W-2 employer of all employees who work exclusively for the Midstream Subsidiaries. Downstream Services is also the W-2 employer of certain corporate level employees who render services to more than one (1) of the WTG Subsidiaries (the “Multi-Sector Employees”).

WTG Downstream Holdings LLC

The following WTG Downstream Holdings LLC companies are affiliates of WTG Downstream Services, LLC:

West Texas Gas Utility, LLC (“WTGU”) is a regulated natural gas distribution and transmission company. Its operations are located in the panhandles of Oklahoma and Texas, the western and southern regions of Texas and in eastern New Mexico. WTGU has district office locations throughout Texas and Oklahoma with the corporate office located in Midland, Texas. WTGU maintains a separate set of books and records and directly pays the majority of its labor costs, general and administrative costs and operating and maintenance costs. WTGU is billed by the Company for certain personnel costs and shared services as discussed in this CAM.

WTG Gas Marketing, LLC. (“WTGGM”) is a wholesale and retail gas brokerage operation and functions out of the Midland, Texas corporate office location. WTGGM maintains a separate set of books and records and directly pays its operating costs. WTGGM is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

Western Gas Interstate Company (“WGI”) is a regulated interstate pipeline utility with operations located in the Oklahoma and Texas panhandles. WGI maintains a separate set of books and

records and directly pays its operating and maintenance costs. WGI is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Gas Transmission Company (“WTGGT”) is a regulated intrastate pipeline utility with operations located in the state of Texas. WTGGT maintains a separate set of books and records and directly pays its operating and maintenance costs. WTGGT is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Hugoton, LP (“WTGH”) is a regulated interstate pipeline utility with its system extending from the southwestern part of Kansas into the Oklahoma panhandle. WTGH maintains a separate set of books and records and directly pays its operating and maintenance costs. WTGH is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Fuels Holdings LLC

The following WTG Fuels Holdings LLC companies are affiliates of WTG Downstream Services, LLC:

WTG Fuels, LLC (“WTGF”) is a company whose assets include automated fuel operations, retail and wholesale petroleum product sales, and convenience stores locations situated primarily in Texas. WTGF maintains a separate set of books and records and directly pays its labor costs and operating and maintenance costs. WTGF is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

Gascard Partners, LP (“GCP”) is a company whose assets include the “Gascard” automated card fueling system, transaction processing software, and hardware systems. GCP maintains a separate set of books and records and directly pays its operating and maintenance costs. Personnel costs for GCP are paid by WTGF and rebilled to the partnership. GCP is billed by the Company for certain shared services as discussed in this CAM.

WTG Midstream LLC

The following WTG Midstream LLC companies are affiliates of WTG Downstream Services, LLC:

Irion County Gas Plant (“Irion”) is a gas processing plant located in Texas. Irion maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Gas Processing, LP (“WTGGP”) is a gathering system and holds a 21% undivided interest in the Kinder Morgan Snyder Gas Plant. The owned gathering systems are located in Scurry, Howard, and Martin Counties in Texas. For accounting and reporting purposes, these systems are uniquely identified and maintained as separate reporting entities but are not separate legal entities and therefore are not separately here. WTGGP and each of the WTGGP gathering systems maintain a separate set of books and records and directly pay its operating and maintenance costs. WTGGP and WTGGP systems are billed for shared overhead services by the Company as discussed in this CAM.

Fuller Gas Plant (“Fuller”) is a gas processing plant located in Texas. Fuller maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

East Vealmoor Plant (“East Vealmoor”) is a gas processing plant located in Texas. East Vealmoor maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG North Permian Midstream LLC (“Sale Ranch”) is a gas processing plant located in Texas. Sale Ranch maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Jameson, LP (“WTGJ”) is a gas processing plant and gathering system located in Texas. WTGJ maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

Ledco, LLC (“Ledco”) is a gas gathering system owned located in central and southern Louisiana. Ledco maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG NGL Marketing, LLC (“NGLMKT”) is a natural gas liquids brokerage operation and functions out of the Midland, Texas corporate office location. NGLMKT maintains a separate set of books and records and directly pays its operating costs. NGLMKT is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG South Permian Midstream, LLC (“WTGSPM”) is a gas processing plant located in Texas. WTGSPM maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Gas Gathering Company, LLC (“WTGGG”) is an intrastate pipeline utility with operations located in the state of Texas. WTGGG maintains a separate set of books and records and directly pays its operating and maintenance costs. WTGGG is billed by the Company for personnel costs and certain shared services as discussed in the CAM.

WTG NGL Pipeline Company, LLC (“NGLPL”) is an intrastate liquids pipeline utility with operations located in the state of Texas. NGLPL maintains a separate set of books and records and directly pays its operating and maintenance costs. NGLPL is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Midstream Marketing, LLC (“WTGMM”) is wholesale and retail gas brokerage operation and functions out of the Midland, Texas corporate office location. WTGMM maintains a separate set of books and records and directly pays its operating costs. WTGMM is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

Low Country Power, LLC (“LCP”) is an electricity generating company in which it uses its gas powered turbines to generate electricity for certain affiliated gas processing plants. LCP maintains a separate set of books and records and directly pays its operating and maintenance costs. LCP is billed for shared overhead services by the Company as discussed in this CAM.

Accounting Codes

WTG Downstream Services uses two main coding structures, one for overhead expenses and the other for rebillable expenses. Overhead expenses initially hit the income statement. At the end of each month all the expenses are zeroed out and rebilled based on the Allocation Method All Companies (9501). Rebillable expenses only hit the balance sheet and are recorded as a receivable.

The WTG Downstream Services coding structure for overhead expenses is shown below:

XXX	XXX	XXX	X-XXXXXX
<u>Company #</u>	<u>GL Acct Major</u>	<u>GL Acct Minor</u>	<u>Billing Code</u>
3 Digits	3 Digits	3 digits	1 Character 6 Digits (Max)

Example:

Company #	095
GL Account #	900-065
Billing Code	U-9501

- The company number assigned to WTG Downstream Services is number 095.
- The GL account number is made up of major and minor fields. The major field represents the account category such as general and administrative expense, code 900. The minor field includes the various types of accounts in that category such as office supplies, code 065 or telephone expense, code 100.
- The billing code field of U-9501 defines the expense as an overhead burden expense that will be rebilled based on the Allocation Method All Companies (9501).

The WTG Downstream Services coding structure for rebillable expenses is shown below:

XXX	XXX	XXX	X-XXXXXX	XXX
<u>Company #</u>	<u>GL Acct Major</u>	<u>GL Acct Minor</u>	<u>Billing Code</u>	<u>Individual ID</u>
3 Digits	3 Digits	3 digits	1 Character 6 Digits (Max)	6 Digits (Max)

Example:

Company #	095
GL Account #	120-145
Billing Code	U-99
Individual ID	16

- The company number assigned to WTG Downstream Services is number 095.
- The GL account number is made up of major and minor fields. When an affiliate is going to be rebilled for a certain expense, it is always coded to the GL Acct Major 120 (Accounts Receivable) and GL Acct Minor 145 (A/R Other).
- The Billing Code field of U-99 defines the expense as a rebillable direct expense.
- The individual ID field defines the affiliate to be rebilled for the shared service cost incurred.

Definitions

Affiliate – Refers to legal entities owned by, or under the common control of the WTG companies.

Allocation Method All Companies (9501) – An allocation method used to allocate expenditures that are applicable to all affiliates. The components of the formula are total expense (including G&A, operating and maintenance expense), gross revenue, gross plant and net income.

Allocation Method Downstream (9502) – An allocation method used to allocate expenditures that are applicable to all affiliates that operate as a natural gas utility. The components of the formula are total expense (including G&A, operating and maintenance expense), gross revenue, gross plant and net income.

Allocation Method Midstream (9503) – An allocation method used to allocate expenditures that are applicable to any affiliates that primarily operate gas gathering and processing facilities. The components of the formula are total expense (including G&A, operating and maintenance expense), gross revenue, gross plant and net income.

Company – In general terms, Company refers to WTG Downstream Services, LLC.

Corporate Office – Headquarters for affiliates located in Midland, Texas.

Direct Assignment Method – The assignment of costs incurred by the Company on behalf of one or more affiliates that are specifically applicable to that affiliate or group of certain affiliates (referred to as Affiliate Specific Services within the Services Agreement).

Entity Group – For purposes of this report an entity group is a group of affiliated companies set up for outside audit purposes. Entity groups include WTGU and its subsidiaries, WTGGP and its affiliates and JLDHC and its subsidiaries.

Shared Services – Shared services are the support functions of the Company that serve the various WTG companies. These services are paid by WTGDS, recorded on its books and rebilled to affiliates through either direct assignment or a defined allocation method as applicable. The support functions include but are not limited to accounting, information technology, communications infrastructure, human resource management (including payroll and benefit plans), insurance services, financial services, general administrative, regulatory compliance, gas procurement, environmental and land services, purchasing services, office infrastructure (including leasehold space and utilities), and professional services (including, but not limited to legal, accounting, engineering, and other consulting services).

<u>Shared Service</u>	Overhead Burden
<u>Description</u>	Shared Services expenses as defined in this CAM.
<u>Provider of Service</u>	WTG Downstream Services, LLC
<u>Affiliate Using Service</u>	All affiliates
<u>Allocation Method</u>	Allocation Method All Companies (9501)
<u>Other Notes</u>	Overhead burden expenses hit the income statement of WTGDS. Each month, all the expenses are zeroed out and rebilled based on the Allocation Method All Companies (9501).
<u>Shared Service</u>	Labor and Related Personnel Costs
<u>Description</u>	Salaries and other personnel-related costs (e.g. health insurance, 401-K contributions, payroll taxes, etc).
<u>Provider of Service</u>	WTG Downstream Services, LLC
<u>Affiliate Using Service</u>	WTG Downstream Services will provide administrative services for Affiliates that do not maintain their own payroll reporting system. These costs are rebilled using one of the allocation methods described below.
<u>Allocation Method</u>	Labor costs are captured through direct time sheet entries of employees. Employees are assigned a company location code. Using that location code, calculated payroll amounts and corresponding payroll expense are tabulated and billed to the appropriate affiliate using one of the following methods: <ul style="list-style-type: none"> • Direct Assignment (U-99 and respective company code) • Allocation Method All Companies (9501) • Allocation Method Downstream (9502)
<u>Other Notes</u>	Certain affiliates do not use this service because a payroll system is maintained by the affiliate and personnel costs are paid directly by the affiliate. These companies include the WTG Midstream companies.

<u>Shared Service</u>	Insurance Expense
<u>Description</u>	Insurance coverage for General Liability, Umbrella, Property, Auto, Workers Comp, Liquor Liability and Miscellaneous Other Fees
<u>Provider of Service</u>	WTG Downstream Services, LLC
<u>Affiliate Using Service</u>	All affiliates
<u>Allocation Method</u>	<p>Various Allocation Methods</p> <p>Premiums for insurance coverage are rebilled using the various allocation methods shown below.</p> <p><u>General Liability</u> – This allocation method is based on through-put volumes for WTG and Plants and gallons for WTG Fuels. Volumes used are for the twelve month period ending March 31st of each year. (Basin & WTNB are excluded from this allocation because they have their own General Liability policies. JLD is also excluded from this allocation.)</p> <p><u>Umbrella</u> – The allocation method is the weighted average of Gross Revenue, Expenses including G&A, Operating and R&M and Payroll expense. Period includes the twelve months of the most recent calendar year end.</p> <p><u>Property</u> – Insured values have been defined based on plant. The percentage of the affiliate company’s insured value to the total plant value is applied to the premium total and billed to the respective affiliate. (WTGX and Basin are excluded from this method and use a pre-determined property value.)</p> <p><u>Auto</u> – Vehicle count is used as allocation method for auto premium.</p> <p><u>Workers Comp</u> – Payroll expense at calendar year end is used for allocation. The percentage of the individual affiliate payroll expense to the total of all affiliate’s payroll expense is applied to the premium total and billed to the respective affiliate.</p> <p><u>Liquor Liability</u> – The premium for liquor liability is charged directly to WTG Fuels, Inc.</p> <p><u>Miscellaneous Other</u> – Premium coverage for other insurance fees is allocated equally among the affiliated companies.</p> <p>Insurance costs are paid out of WTGDS and assigned to the appropriate affiliate.</p>
<u>Other Notes</u>	Currently, insurance coverage is for the period from June 1 st to May 31 st each year. Premium allocations are recalculated annually using data from affiliate financial statements for the most recent calendar year end.

<u>Shared Service</u>	P-Card Purchases
<u>Description</u>	Select employees have been issued a Bank Card which can be used for company use in the purchase of certain items.
<u>Provider of Service</u>	WTG Downstream Services, LLC
<u>Affiliate Using Service</u>	All affiliates, as applicable
<u>Allocation Method</u>	Expenses for P-Card purchases are allocated using the following methods. These costs are paid out of WTGDS and then rebilled to the appropriate affiliate using the following: <ul style="list-style-type: none"> • Direct Assignment (U-99 and respective company code) • Allocation Method All Companies (9501) • Allocation Method Downstream (9502) • Allocation Method Midstream (9503)
<u>Other Notes</u>	Bank card charges are paid monthly to Wells Fargo out of WTGDS.
<u>Shared Service</u>	Phone – Wireless and Wireline Expense
<u>Description</u>	WTGDS utilizes the company Advantix to manage all the wireless and landline accounts across all companies
<u>Provider of Service</u>	WTG Downstream Services, LLC
<u>Affiliate Using Service</u>	All affiliates, as applicable
<u>Allocation Method</u>	Expenses for phone services are allocated using the following methods. These costs are paid out of WTGDS and then rebilled to the appropriate affiliate using the following: <ul style="list-style-type: none"> • Direct Assignment (U-99 and respective company code) • Allocation Method All Companies (9501) • Allocation Method Downstream (9502) • Allocation Method Midstream (9503)
<u>Other Notes</u>	Wireline and Wireless charges are paid to OneSource monthly out of WTGDS.

<u>Shared Service</u>	Electricity
<u>Description</u>	WTGDS utilizes the company BP Energy Retail Company LLC to manage some of the electricity accounts across all companies
<u>Provider of Service</u>	WTG Downstream Services, LLC
<u>Affiliate Using Service</u>	All affiliates, as applicable
<u>Allocation Method</u>	Electricity charges are are paid out of WTGDS and then rebilled to the appropriate affiliate using the following: <ul style="list-style-type: none"> • Direct Assignment (U-99 and respective company code)
<u>Other Notes</u>	Electricity charges are paid to BP monthly out of WTGDS.

<u>Shared Service</u>	Affiliate Specific Services
<u>Description</u>	Expense includes any specifically identifiable expense incurred for one or more affiliate for Affiliate Specific Services which are not offered to all affiliates under the Services Agreement
<u>Provider of Service</u>	WTG Downstream Services LLC
<u>Affiliate Using Service</u>	All affiliates, as applicable
<u>Allocation Method</u>	Direct Assignment Method
<u>Other Notes</u>	

Section 7, Item A.

5969826	Field Equipment	SOIL RESISTIVITY DIGITAL	394.0	200630	GROOM & ENVIRONS	Both	3,782.44	TX	100.00%	3,782.44	2020
5969860	Field Equipment	LOCATOR 8869V3 PLS 3 WATT	394.0	200731	SAN ANTONIO AREA - RURAL	Both	2,943.32	TX	100.00%	2,943.32	2020
5969865	Field Equipment	SENSIT GOLD CO2 MONITORS	394.0	200831	SOMERSET & ENVIRONS	Both	7,931.66	TX	100.00%	7,931.66	2020
5969872	Field Equipment	POLARIS RANGER 2017	394.0	200930	CANADIAN & ENVIRONS	Both	9,000.00	TX	100.00%	9,000.00	2020
5969873	Field Equipment	MODEL UFLO6213 FLOW	394.0	200930	TRANS PECOS AREA - RURAL	Both	3,065.09	TX	100.00%	3,065.09	2020
5969879	Field Equipment	SENSIT GOLD G2 EX/H2S	394.0	201031	GUYMON AREA TX - RURAL	Both	2,470.71	TX	100.00%	2,470.71	2020
5969882	Field Equipment	SENSIT GOLD G2 TC	394.0	201130	DALHART AREA - RURAL	Both	2,574.29	TX	100.00%	2,574.29	2020
6669787	Field Equipment	SENSIT GOLD G2 TC EX/TC	394.0	200229	BOISE CITY OK	Out of state	4,751.62	OK	0.00%	-	2020
6069817	Equipment	WELDING MACHINE AND	398.0	200531	SAN ANTONIO AREA - RURAL	Jurisdictional	2,500.00	TX	100.00%	2,500.00	2020
6069818	Equipment	REPLACED 3 TON AC SYSTEM	398.0	200531	AMARILLO	Both	5,000.00	TX	100.00%	5,000.00	2020
6069825	Equipment	GUYMON OFFICE SHOP HEATER	398.0	200630	GUYMON AREA TX - RURAL	Both	2,999.31	TX	100.00%	2,999.31	2020
5669881	Communication Equipmer	ITRON MOBILE RADIO	397.0	201130	HOME OFFICE G&A	Both	45,375.35	CORP	94.25%	42,766.27	2020

WORKPAPERS
TO
DIRECT TESTIMONY
OF
AMANDA EDGMON

Workpapers to the Direct Testimony of Amanda Edgmon are being provided in electronic format.

CASE NO. 00017816

**STATEMENT OF INTENT OF
WEST TEXAS GAS UTILITY, LLC TO
INCREASE GAS UTILITY RATES
WITHIN THE UNINCORPORATED
AREAS OF TEXAS**

§
§
§
§
§

**BEFORE THE
RAILROAD COMMISSION
OF TEXAS**

DIRECT TESTIMONY

OF

MATTHEW S. SMITH, P.E.

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

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LIST OF EXHIBITS

- EXHIBIT MSS-1 Annual Investment by Category (2020-2023)
EXHIBIT MSS-2 Jurisdictional and Non-Jurisdictional Investment (2020-2023)

1 **DIRECT TESTIMONY OF MATTHEW S. SMITH, P.E.**

2 **I. INTRODUCTION AND QUALIFICATIONS**

3 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

4 A. My name is Matthew S. Smith. My business address is 303 Veterans Airpark Lane,
5 Suite 5000, Midland, Texas 79705.

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

7 A. I am employed by West Texas Gas Utility, LLC (“WTGU” or the “Company”) as
8 the Vice President of Operations for its regulated pipeline systems.

9 **Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF**
10 **OPERATIONS FOR WTGU?**

11 A. I am responsible for the execution of, and compliance with, WTGU’s Operations
12 and Maintenance Plan applicable to its distribution and transmission pipeline
13 systems in Texas and Oklahoma. Additionally, I help to coordinate and oversee
14 various levels of directors, managers, and supervisors. For instance, WTGU’s
15 Compliance director is directly responsible for the oversight and execution of
16 Integrity Management, Distribution Integrity Management, Safety, Operations and
17 Maintenance, Operator Qualification, and Public Awareness Plans. Operations
18 directors and managers are responsible for operating the pipeline systems within
19 certain assigned geographical areas. Field supervisors are responsible for the work
20 performed by the service and maintenance staff.

21 **Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.**

22 A. I am a licensed professional engineer with a degree in Mechanical Engineering
23 from Mississippi State University. I worked for CenterPoint Energy, Inc.
24 (“CenterPoint”) for over 15 years in various engineering and operations positions

1 of increasing responsibility. I have experience in the design and execution of
2 natural gas relocation, system improvement, and customer additions projects —
3 including operational oversight of construction and maintenance activities relating
4 to the systems. I also previously held the role of Distribution Integrity Manager
5 overseeing CenterPoint’s efforts to comply with applicable integrity management
6 rules and managed the execution of engineering design activities relating to
7 CenterPoint’s assets located within the State of Texas. I was hired as the Associate
8 Vice President of Operations for WTGU in February 2024 and promoted to Vice
9 President in June 2024.

10 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY**
11 **COMMISSIONS?**

12 A. Yes, I provided testimony before the Railroad Commission of Texas
13 (“Commission”) in Gas Utilities Docket (“GUD”) No. 10669 and Docket No. OS-
14 23-00015513.

15 **Q. HAVE YOU PRESENTED TESTIMONY IN ANY OTHER REGULATORY**
16 **PROCEEDINGS?**

17 A. Yes. As Distribution Integrity Manager for CenterPoint, I supported several
18 company programs before the Arkansas Public Service Commission.

19 **Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR**
20 **DIRECT SUPERVISION?**

21 A. Yes, it was.

22 **Q. ARE YOU SPONSORING OR CO-SPONSORING ANY SCHEDULES?**

23 A. Yes. I am co-sponsoring the following schedules:

1 B-1 Operations and Maintenance Expense

2 C-5 Gas Reliability Infrastructure Program Additions

3 J-3 Pipe Replacement Cost Analysis

4 J-4 Meter Replacement Cost Analysis

5 **Q. WERE THESE SCHEDULES PREPARED BY YOU, WITH YOUR**
6 **KNOWLEDGE OR UNDER YOUR SUPERVISION?**

7 A. Yes, they were.

8 **Q. HOW DOES YOUR TESTIMONY RELATE TO OTHER COMPANY**
9 **WITNESSES IN THIS RATE FILING?**

10 A. My testimony relates to Company witnesses Jack J. King and Amanda Edgmon
11 who also support the Company's operations and investment.

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

14 A. The purpose of my testimony is to describe certain key WTGU field operations and
15 expenses. I also support the Company's request to modify the jurisdictional factors
16 used to determine what portion of the Company's capital investment will be
17 recovered from jurisdictional customers.

18 **Q. ARE YOU SPONSORING ANY EXHIBITS?**

19 A. Yes, I am sponsoring the exhibits listed in the table of contents.

20 **II. WTGU'S CONSTRUCTION AND FIELD OPERATIONS**

21 **Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF WTGU'S DISTRICT**
22 **OFFICES.**

23 A. WTGU currently maintains twelve (12) district offices that are located from the
24 Oklahoma Panhandle down to Frio County in South Texas. These offices function

1 as “report-to-duty” stations for district managers, supervisors, field personnel and
2 customer service staff. The Texas district offices are located in Lytle, Junction,
3 Fort Stockton, Kermit, Wolfforth, Lubbock, Shamrock, Canadian, Stratford,
4 Amarillo, Uvalde and Dalhart. The Oklahoma offices are located in Texhoma and
5 Beaver.

6 **Q. PLEASE EXPLAIN WHY WTGU’S DISTRICT OFFICES IN SHAMROCK**
7 **AND TEXHOMA ARE RESPONSIBLE FOR OPERATIONS IN TWO**
8 **STATES.**

9 A. Based on their geographic location, it is more efficient and cost effective to assign
10 the Shamrock and the Texhoma offices with responsibility for field operations in
11 both Texas and Oklahoma.

12 **Q. WHAT IS WTGU’S PROCESS TO ENSURE THAT COMPANY**
13 **OPERATIONS AND MAINTENANCE (“O&M”) EXPENSES ARE FAIR,**
14 **JUST, AND REASONABLE?**

15 A. Each manager is held responsible for the O&M expenses charged to their district.
16 These expenses are reviewed for reasonableness and compared to the prior year
17 performance for the same period. Also, outside of basic inventory (new housing
18 developments, large projects and the Distribution Integrity Management Plan
19 (“DIMP”)), WTGU creates a material list for each project and orders all the
20 material packaged and delivered at a reduced cost from our supplier. WTGU also
21 has a “container” program for our regular inventory. Our supplier stocks each
22 container at each district and maintains the inventory. This saves money by

1 ordering volume and distributing it through the districts as opposed to each district
2 ordering single items on a project by project basis (which would cost more).

3 **Q. WHAT IS THE BIDDING PROCESS FOR CONSTRUCTION JOBS?**

4 A. WTGU distributes formal requests for bids on large construction and replacement
5 projects. Interested contractors are given project specifications and an opportunity
6 for a field inspection. After bids are received, WTGU evaluates them, accepts the
7 lowest reasonable bid proposal, and executes a construction contract with the
8 contractor. For smaller projects, WTGU compares informal price quotes from local
9 area suppliers and contractors to ensure that a competitive price is received for
10 goods and services.

11 **Q. HOW DOES WTGU MONITOR CONSTRUCTION PROJECT**
12 **SPENDING?**

13 A. Before beginning a project, costs are estimated based on historical experience and
14 are submitted for approval to a corporate officer. Each approved project is assigned
15 a project identification number. Costs are accumulated under the project ID number
16 as invoices are received from suppliers and contractors. Accumulated project costs
17 are reviewed on an ongoing basis during construction and, at the completion of the
18 project, they are reviewed against the initial estimated budget.

19 **Q. WHAT ADDITIONAL OVERSIGHT DO YOU HAVE ON OTHER**
20 **EXPENDITURES?**

21 A. Each district manager must request a purchase order for any non-recurring
22 expenditure (e.g., equipment, inventory, service, tools, maintenance, etc.).

1 Purchase order requests are reviewed by the appropriate level of leadership for
2 compliance with the defined approval matrix.

3 **Q. WHAT IS WTGU'S PIPELINE SAFETY DIMP PROGRAM?**

4 A. WTGU's DIMP program is a written plan that was developed in compliance with
5 49 CFR Part 192 - Subpart P. The purpose of the DIMP plan is to gather knowledge
6 of WTGU's distribution systems, identify threats to the systems' integrity, evaluate
7 and rank the risks to the systems, implement measures to address those risks, and
8 evaluate the effectiveness of the plan. WTGU has generated a detailed digital
9 mapping system of its distribution pipeline system and initiated an automated leak
10 tracking system to help monitor the system risks and the plan's effectiveness.
11 WTGU also utilizes a detailed engineering model to evaluate performance and rank
12 the priority of identified risks.

13 **Q. EXPLAIN WTGU'S STEEL LINE REPLACEMENT PROGRAM.**

14 A. Prior to August 1, 2011, 16 Texas Administrative Code § 8.209, required WTGU
15 to submit its risk-based removal or replacement program to the Commission's
16 Pipeline Safety Division. WTGU's risk-based program uses information collected
17 by the DIMP plan to determine a risk ranking of factors threatening the distribution
18 system. Based on the risk analysis, WTGU determines the pipeline segments or
19 facilities posing the highest risk and schedules the replacement of at least 5% of
20 these facilities annually. In 2023, WTGU spent more than \$8,000,000 to replace
21 suspect mains and service lines situated primarily within WTGU's older municipal
22 distribution systems serving jurisdictional customers.

1 **Q. WHAT CHANGES HAVE BEEN MADE TO COMPLY WITH PIPELINE**
2 **SAFETY AND OTHER REGULATORY REQUIREMENTS SINCE**
3 **WTGU'S LAST RATE CASE?**

4 A. An increased focus on safety has led regulators to raise the Company's required
5 annual percentage of DIMP investment from 5% to 8% per year. This increase
6 materially changed the amount of investment that the Company must make in its
7 system each year. Specifically, WTGU initially identified over 300 miles of pipe
8 that, pursuant to DIMP, is slated for replacement. WTGU had been replacing, on
9 average, approximately 90,000 feet of pipe per year. With the increase in the target
10 percentage to 8%, the Company now targets approximately 143,000 feet in annual
11 DIMP replacement footage at an annual cost of approximately \$8,000,000.

12 Additionally, the Company continues to monitor the changing regulatory
13 environment for additional requirements that may be implemented. For example,
14 currently the Leak Detection and Repair ("LDAR") regulation is under review at a
15 federal level. If passed, this regulation ". . . [would] strengthen leakage survey and
16 patrolling requirements; performance standards for advanced leak detection
17 programs; leak grading and repair criteria with mandatory repair timelines;
18 requirements for mitigation of emissions from blowdowns; pressure relief device
19 design, configuration, and maintenance requirements; and clarified requirements
20 for investigating failures."¹ In the proposed form, operators may experience
21 additional costs. For example, operators may need to purchase new leak detection
22 equipment to comply with the proposed performance standard for that equipment.

¹ [Pipeline Safety: Gas Pipeline Leak Detection and Repair | PHMSA available at https://www.govinfo.gov/content/pkg/FR-2023-05-18/pdf/2023-09918.pdf.](https://www.govinfo.gov/content/pkg/FR-2023-05-18/pdf/2023-09918.pdf)

1 **Q. HAVE THERE BEEN ANY OTHER CHANGES IN THE COMPANY'S**
2 **OPERATIONS OR INVESTMENT PRACTICES SINCE ITS LAST RATE**
3 **CASE?**

4 A. Yes. The Company has investigated and deployed new technology to ensure
5 continued compliance and efficient operations. For example, the Company has
6 modified its GIS mapping system to allow for the direct entry of field data.
7 Currently, each time a mainline is exposed, the field technician has the opportunity
8 to enter an inspection report – including photographs – directly into the mapping
9 system. This information becomes available to the integrity management team to
10 continue analysis of the threats and risks in the system.

11 Additionally, the Company is working to pilot the deployment of
12 Automated Meter Reading (“AMR”) technology in the City of White Deer. This
13 technology utilizes a cellular network to remotely read meters. Pending the
14 outcome of the pilot deployment, the Company intends to continue deployment of
15 AMR technology more broadly across the service territory. As the technology is
16 more broadly deployed, the Company anticipates more accurate meter reads for
17 customers and increased efficiency in the operations of the natural gas system.

18 **Q. WITH REGARD TO FIELD OPERATIONS, DOES WTGU RELY ON ANY**
19 **AFFILIATES TO PROVIDE SERVICE TO CUSTOMERS?**

20 A. No.

1 **Q. DO WTGU FIELD PERSONNEL PERFORM SERVICES FOR ANY OF**
2 **WTGU'S AFFILIATES?**

3 A. WTGU field technicians may occasionally perform activities such as annual
4 patrols, line locating, leak survey, and cathodic protection maintenance for WTG
5 Gas Transmission Company, LLC ("WTGGT"). However, these activities are not
6 performed on a regular basis within any given year.

7 **III. CAPITAL INVESTMENT ISSUES**

8 **Q. WHICH WITNESSES SUPPORT THE PRUDENCE OF INVESTMENT IN**
9 **THE COMPANY'S SYSTEM SINCE THE LAST RATE CASE?**

10 A. Mr. King and I support the prudence of all projects undertaken since Docket
11 No. OS-20-00004347. More specifically, I can address the day-to-day work on the
12 projects at issue in this proceeding, their necessity, and the steps the Company takes
13 to ensure the reasonableness of all project costs. Ms. Edgmon, because she was
14 responsible for making the filings themselves, presents the Company's annual Gas
15 Reliability Infrastructure Program ("GRIP") filings since Docket No. OS-20-
16 00004347.

17 **Q. PLEASE DESCRIBE THE CAPITAL INVESTMENT FOR WHICH THE**
18 **COMPANY SEEKS A PRUDENCE DETERMINATION IN THIS CASE.**

19 A. The Company continually makes substantial investments in its infrastructure to
20 ensure the safe and reliable provision of gas distribution service to our customers.
21 The Company's capital additions since Docket No. OS-23-00004347 total
22 approximately \$61.4 million through December 31, 2023. As shown in Exhibit
23 MSS-1, the main categories of investment were:

- 1 • Buildings and Equipment: about \$2.4 million was invested in general
2 and other plant;
- 3 • DIMP: more than \$30 million for DIMP replacement work;
- 4 • System Growth: approximately \$25 million was for system expansion;
- 5 • System Integrity: over \$1.8 million was for system and public
6 improvements; and
- 7 • Measurement: approximately \$1.9 million related to the purchase and
8 installation of meter reading equipment and ERTs (Encoder, Receiver,
9 Transmitters).

10 Approximately 52% of the total investment represented here is directly related to
11 safety.

12 **Q. IS SOME OF THIS INVESTMENT CURRENTLY BEING RECOVERED**
13 **THROUGH THE COMPANY’S GRIP RATES?**

14 A. Yes. Some of this investment is currently being recovered through GRIP rates the
15 Commission approved for GRIP filings the Company has made since the
16 Company’s last rate proceeding. Following Docket No. OS-20-00004347, WTGU
17 made four GRIP filings, with the most recent one filed on May 17, 2024, to recover
18 capital investment made in 2023.

19 **Q. WHAT HAVE BEEN WTGU’S CAPITAL ADDITIONS BY YEAR SINCE**
20 **THE LAST RATE CASE?**

21 A. As shown on Exhibit MSS-1, capital additions in Texas since 2019 have been the
22 following:

- 23 2020: \$18,668,741
- 24 2021: \$11,741,728
- 25 2022: \$15,295,068

1 2023: \$15,682,229

2 The investment amounts noted above have been primarily driven by growth, public
3 improvement projects, and the need to replace aging infrastructure.

4 **Q. SINCE THE LAST RATE CASE, HOW MUCH INVESTMENT HAS THE**
5 **COMPANY MADE FOR JURISDICTIONAL AND NON-**
6 **JURISDICTIONAL CUSTOMERS IN TEXAS?**

7 A. As shown in Exhibit MSS-2, since January 1, 2020, the investment has been:

- 8 • 84.5% or \$51.9 million for Jurisdictional Customers;
- 9 • 8.65% or \$5.3 million for Non-Jurisdictional customers; and
- 10 • 6.85% or \$4.2 million for both customer types.

11 **Q. IS THE COMPANY REQUESTING A PRUDENCY DETERMINATION**
12 **FOR CAPITAL INVESTMENT MADE SINCE 2019?**

13 A. Yes, the Company is requesting a prudency determination on all plant placed in
14 service from January 1, 2020 through December 31, 2023.

15 **Q. IS ALL OF THE CAPITAL INVESTMENT BOOKED TO PLANT AS**
16 **ADJUSTED THROUGH DECEMBER 31, 2023 USED AND USEFUL IN**
17 **PROVIDING UTILITY SERVICE?**

18 A. Yes.

19 **Q. IS ALL OF THE COMPANY'S CAPITAL INVESTMENT IN WTGU**
20 **PRUDENT AND REASONABLY AND NECESSARILY INCURRED?**

21 A. Yes. All of the Company's capital investment in the areas it serves throughout
22 Texas was prudent and was reasonably and necessarily incurred in order to provide
23 a safe and reliable system with an appropriate level of customer service.

1 **Q. ARE YOU AWARE OF THE COMPANY’S USE OF A “JURISDICTIONAL**
2 **FACTOR” IN ITS GRIP FILINGS?**

3 A. Yes. This was an issue in the Company’s last rate case. I understand in the GRIP
4 filings that a “jurisdictional factor” is used to calculate how much of the total
5 incremental capital investment the Company can recover from jurisdictional
6 customers. Ms. Edgmon addresses that issue in detail in her direct testimony and
7 explains the Company’s request to revise the way the Company recovers
8 investment from jurisdictional customers.

9 **Q. WHAT IS YOUR UNDERSTANDING OF WHY THE COMPANY WANTS**
10 **TO CHANGE THE WAY IT RECOVERS INVESTMENT AMOUNTS**
11 **FROM JURISDICTIONAL CUSTOMERS?**

12 A. Going forward, the Company wants to more closely align recovery of the cost of
13 its investment from the customers who benefit from that investment.

14 **Q. CAN YOU PROVIDE AN EXAMPLE OF CAPITAL INVESTMENT THAT**
15 **IS MADE SOLELY FOR JURISDICTIONAL CUSTOMERS?**

16 A. Yes. The Company is experiencing significant jurisdictional customer growth
17 within the Lubbock, Amarillo, and San Antonio areas. With this growth, the
18 Company is not only investing in the installation of new mainlines to serve these
19 communities but, also, in reinforcement of the existing distribution system to
20 ensure continued reliability of service to current jurisdictional customers.

21 Additionally, the Company’s DIMP program has been developed to address
22 any risks in the system with the highest risk assets taking priority. In general, a risk
23 assessment is driven by the likelihood of an incident occurring and the consequence

1 should that event occur. The consequence component of the assessment increases
2 as customer density around an asset increases. Therefore, the assets targeted for
3 replacement are generally located where there is higher customer density such as
4 residential areas comprised only of jurisdictional customers in Canadian, Junction,
5 Shamrock, Kermit, or other cities within the operating territory of the Company.

6 As an example of a recent DIMP project, the replacement of approximately
7 13,000 feet of mainline in the city of Kermit, Texas serves to ensure the continued
8 safe and reliable delivery of natural gas to the residents of Kermit. The customers
9 taking service from this project are Domestic (or residential) customers. It is
10 reasonable for the Company to fully recover the costs of DIMP projects such as this
11 from jurisdictional customers.

12 **Q. CAN YOU PROVIDE AN EXAMPLE OF CAPITAL INVESTMENT THAT**
13 **IS MADE FOR BOTH JURISDICTIONAL AND NON-JURISDICTIONAL**
14 **CUSTOMERS?**

15 A. Yes. As identified in Exhibit MSS-2, there are various capital investments that may
16 benefit both jurisdictional and non-jurisdictional customers. This includes
17 vehicles, equipment, or facility related items. For example, a vehicle purchased in
18 the Dalhart area will be used in the installation and maintenance of assets that
19 benefit both jurisdictional and non-jurisdictional customers.

20 **IV. ADDITIONAL SCHEDULES SPONSORED**

21 **Q. DO YOU SPONSOR OR CO-SPONSOR ANY ADDITIONAL SCHEDULES**
22 **ASSOCIATED WITH THE COMPANY'S RATE FILING PACKAGE?**

23 A. Yes, I co-sponsor Schedules B-1, C-5, J-3, and J-4.

1 **Q. PLEASE DESCRIBE THE SCHEDULE OF PIPE REPLACEMENT COST**
2 **ANALYSIS (J-3).**

3 A. For its Pipe Replacement Cost Analysis, WTGU used conservative estimates for
4 pipeline materials and construction. Pipeline footages for this analysis come
5 directly off WTGU's Form 7100 filing and DIMP assessment plan. The estimated
6 price-per-foot used in the analysis includes the cost of materials (based on SDR 11
7 poly pipe or standard wall steel pipe), installation costs based on recent WTGU
8 experience, and minimal right-of-way costs. In the last rate case, Dr. Fairchild used
9 a 1" diameter replacement assumption. This approach, however, does not
10 accurately reflect the diverse makeup of the Company's system, or the fact that the
11 majority of pipe operating is at least 2" in diameter. As such, Dr. Fairchild is using
12 a replacement assumption of 2" diameter pipe, which he addresses in his direct
13 testimony.

14 **Q. PLEASE DESCRIBE THE METER REPLACEMENT COST ANALYSIS**
15 **(SCHEDULE J-4) THAT WAS MADE A PART OF THE RATE MODEL.**
16 **EXPLAIN WHERE THE REPLACEMENT COST ESTIMATES CAME**
17 **FROM AND WHY ORIGINAL COST IS UNAVAILABLE.**

18 A. WTGU's distribution assets are composed of more than fifteen different
19 acquisitions made by WTGU over the past 30-plus years. Most of these assets were
20 previously owned by small municipalities or small, family-owned businesses that
21 did not maintain their original cost historical data. As a result, WTGU cannot
22 provide a complete original cost analysis of its distribution plant.

1 For its Meter Replacement Cost Analysis, WTGU used conservative
2 replacement cost estimates for the four primary types of customer meter settings.
3 These estimates include the cost of the service rider and meter run including any
4 regulation, valves, and fittings. More specifically:

- 5 • Residential – these are low-volume positive displacement meters,
6 typically represented by AL-175 or Rockwell 200 type meters;
- 7 • Small Commercial – these are higher volume positive displacement
8 meters, typically represented by AL-800 or Rockwell 750 type meters;
- 9 • Irrigation – the same positive displacement meter type used in Small
10 Commercial applications or, for larger irrigation customers, a Roots
11 rotary type meter is installed; and
- 12 • Large Commercial – these meter sets are usually connected with high
13 volume turbine and ultrasonic type meters or an orifice meter run tied
14 to an electrical measurement unit (Total Flow).

15 V. CONCLUSION

16 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

17 A. Yes, it does.


STATE OF TEXAS §
 §
COUNTY OF MIDLAND §

AFFIDAVIT OF MATTHEW S. SMITH

BEFORE ME, the undersigned authority, on this day personally appeared Matthew S. Smith, who having been placed under oath by me did depose as follows:

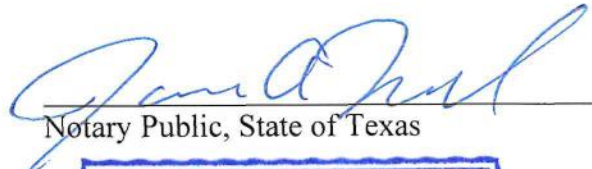
1. “My name is Matthew S. Smith. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is Vice President of Operations for West Texas Gas Utility, LLC.
2. I have prepared the foregoing direct testimony and the information contained in this document is true and correct to the best of my knowledge.”

Further affiant sayeth not.

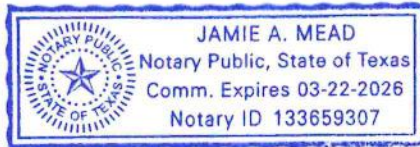


 Matthew S. Smith

SUBSCRIBED AND SWORN TO BEFORE ME by the said Matthew S. Smith on this 26th day of June 2024.



 Notary Public, State of Texas



Texas Specific Allocations by Category

Sum of Texas Allocated Cost Project Reason	Year				Grand Total
	2020	2021	2022	2023	
Buildings and Equipment	889,713	762,027	607,080	113,675	2,372,495
Buildings			39,080	7,473	46,553
Communication Equipment	42,766	4,098	14,329	18,201	79,394
Equipment	786,775	631,869	454,817	-	1,873,460
Field Equipment	57,576	104,680	94,563	88,001	344,820
Office Equipment	2,596	21,380	4,292	-	28,268
DIMP	8,127,602	6,406,477	8,095,442	7,755,979	30,385,499
DIMP	8,127,602	6,406,477	8,095,442	7,755,979	30,385,499
System Growth	9,345,555	4,251,279	5,006,646	6,338,935	24,942,415
System Growth	9,345,555	4,251,279	5,006,646	6,338,935	24,942,415
System Integrity	107,182	181,063	922,123	595,910	1,806,278
System Integrity	107,182	181,063	922,123	595,910	1,806,278
Measurement	198,689	140,882	663,777	877,730	1,881,078
Measurement	198,689	140,882	663,777	877,730	1,881,078
Land	-	-	-	-	-
Land	-	-	-	-	-
Grand Total	18,668,741	11,741,728	15,295,068	15,682,229	61,387,766

Texas Specific Utilities Investment

Customers Benefitted	Sum of Texas Allocated Cost	
Jurisdictional	\$	51,876,893
Non-Jurisdictional	\$	5,308,143
Both	\$	4,202,729
Grand Total	\$	61,387,766

Texas Investment		
\$	51,876,893	84.51%
\$	5,308,143	8.65%
\$	4,202,729	6.85%
\$	61,387,766	100.00%

WORKPAPERS
TO
DIRECT TESTIMONY
OF
MATTHEW S. SMITH, P.E.

Workpapers to the Direct Testimony of Matthew S. Smith, P.E. are being provided in electronic format.

CASE NO. 00017816

**STATEMENT OF INTENT OF
WEST TEXAS GAS, INC. TO
INCREASE GAS UTILITY RATES
WITHIN THE UNINCORPORATED
AREAS OF TEXAS**

§
§
§
§
§

**BEFORE THE
RAILROAD COMMISSION
OF TEXAS**

DIRECT TESTIMONY

OF

DANE A. WATSON, PE, CDP

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

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LIST OF EXHIBITS

- EXHIBIT DAW-1 West Texas Gas Depreciation Study at December 31, 2023
- EXHIBIT DAW-2 List of Testimony Appearances

1 **EXECUTIVE SUMMARY OF DANE A. WATSON, PE, CDP**

2 I have performed a depreciation study of West Texas Gas Utility, LLC (“WTGU”
 3 or the “Company”) based on the depreciable plant in service on December 31, 2023. The
 4 results of my depreciation study support an annualized depreciation expense for WTGU of
 5 approximately \$5.9 million. This represents a decrease of approximately \$769,000 over
 6 the annualized depreciation expense calculated on year-end 2023 investment using the
 7 current depreciation rates on a system-wide basis. A table summarizing the proposed
 8 versus existing accrual by function is shown below.

Utility Function	Plant Balance at 12/31/2023	Existing Annual Accrual	Proposed Annual Accrual	Difference
Total Intangible Plant	\$ 378,315	\$ -	\$ -	\$ -
Total Gathering Plant	3,148,811	-	-	-
Total Transmission Plant	52,329,558	1,317,333	1,165,158	(152,176)
Total Distribution Plant	176,288,117	4,609,377	4,074,103	(535,274)
Total General Plant	16,317,866	740,142	677,272	(62,871)
Amortized Reserve Difference			(18,292)	(18,292)
Grand Total	\$ 248,462,667	\$ 6,666,853	\$ 5,898,241	\$ (768,612)

9 Detailed information regarding the service life and net salvage characteristics that
 10 support my proposed depreciation rates can be found in the depreciation study included as
 11 Exhibit DAW-1 of my testimony, as well as in my workpapers.

1 **DIRECT TESTIMONY OF DANE A. WATSON**

2 **I. POSITION AND QUALIFICATIONS**

3 **Q. PLEASE STATE YOUR NAME AND BY WHOM YOU ARE EMPLOYED.**

4 A. My name is Dane A. Watson. I am a Partner of Alliance Consulting Group.
5 Alliance Consulting Group provides consulting and expert services to the utility
6 industry.

7 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

8 A. I am filing testimony on behalf of WTGU.

9 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

10 A. I hold a Bachelor of Science degree in Electrical Engineering from the University
11 of Arkansas at Fayetteville and a master's degree in Business Administration from
12 Amberton University.

13 **Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION
14 EXPERT?**

15 A. Yes. The Society of Depreciation Professionals ("SDP") has established national
16 standards for depreciation professionals. The SDP administers an examination and
17 has certain required qualifications to become certified in this field. I met all
18 requirements and hold a Certified Depreciation Professional certification.

19 **Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.**

20 A. Since graduating from college in 1985, I have worked in the area of depreciation
21 and valuation. I founded Alliance Consulting Group in 2004 and am responsible
22 for conducting depreciation, valuation, and certain accounting-related studies for
23 clients in various industries. My duties related to depreciation studies include the
24 assembly and analysis of historical and simulated data, conducting field reviews,

1 determining service life and net salvage estimates, calculating annual depreciation,
2 presenting recommended depreciation rates to utility management for its
3 consideration, and supporting such rates before regulatory bodies.

4 My prior employment from 1985 to 2004 was with Texas Utilities Electric
5 Company and successor companies (“TXU”). During my tenure with TXU, I was
6 responsible for, among other things, conducting valuation and depreciation studies
7 for the domestic TXU companies. During that time, I served as Manager of
8 Property Accounting Services and Records Management in addition to my
9 depreciation responsibilities.

10 I have twice been Chair of the Edison Electric Institute (“EEI”) Property
11 Accounting and Valuation Committee and have been Chairman of EEI’s
12 Depreciation and Economic Issues Subcommittee. I am a Registered Professional
13 Engineer in the State of Texas. I am a Senior Member of the Institute of Electrical
14 and Electronics Engineers (“IEEE”) and served for several years as an officer of
15 the Executive Board of the Dallas Section of IEEE. I am also a twice Past-President
16 of the Society of Depreciation Professionals.

17 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY**
18 **COMMISSIONS?**

19 A. Yes. In my 35-year career, I have conducted depreciation studies, filed written
20 testimony, and/or testified in 260 cases before more than thirty-five different state
21 and regulatory agencies across the United States. I have testified in more than 20
22 separate proceedings before the Railroad Commission of Texas (“Commission”).
23 A list of my appearances is shown in Exhibit DAW-2. I have also appeared in

1 Federal Energy Regulatory Commission Docket No. 02-7-00 as an industry panelist
2 on asset retirement obligations.

3 **II. PURPOSE AND SUMMARY OF DIRECT TESTIMONY**

4 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**
5 **PROCEEDING?**

6 A. I sponsor and support the depreciation study performed for WTGU and its natural
7 gas assets. The depreciation study attached as Exhibit DAW-1 produces the
8 depreciation rates used to determine the depreciation expense for the WTGU assets
9 included in this filing.

10 **Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR**
11 **TESTIMONY?**

12 A. Yes. I have prepared or supervised the preparation of the exhibits listed in the table
13 of contents.

14 **Q. WHAT DEPRECIATION EXPENSE ARE YOU RECOMMENDING IN**
15 **THIS PROCEEDING FOR WTGU?**

16 A. Based on the depreciation study, which analyzed the Company's depreciable plant
17 in service at December 31, 2023, I recommend an annualized depreciation expense
18 of approximately \$5.9 million. This represents a decrease of approximately
19 \$769,00 over the annualized depreciation expense calculated on investment as of
20 December 31, 2023, using the existing depreciation rates approved by this
21 Commission in open settlement Docket No. OS-20-00004347, formerly Gas
22 Utilities Docket ("GUD") No. 10998.

1 **Q. WHAT ARE THE PRIMARY FACTORS THAT HAVE INFLUENCED THE**
2 **CHANGE IN THE COMPANY'S DEPRECIATION RATES?**

3 A. The primary factors that influenced the change in depreciation rates for WTGU are
4 changes to average service lives and historical accumulated depreciation reserve
5 levels.

6 **Q. DOES THE DEPRECIATION STUDY YOU SPONSOR IN THIS CASE**
7 **REFLECT THE MOST CURRENT DATA AVAILABLE FOR WTGU**
8 **ASSETS?**

9 A. Yes. The data used reflects the most recent experience and future expectations for
10 life and net salvage characteristics for WTGU assets.

11 **III. WEST TEXAS GAS DEPRECIATION STUDY**

12 **A. Summary of the Depreciation Study Results**

13 **Q. DID YOU PREPARE THE WTGU DEPRECIATION STUDY?**

14 A. Yes. The WTGU Study is attached to my testimony as Exhibit DAW-1. The study
15 in Exhibit DAW-1 analyzes the life and net salvage percentage for the property
16 groups associated with the Texas intangible, gathering, transmission, distribution
17 and general plant assets of WTGU at December 31, 2023.

18 **Q. WHAT PROPERTY IS INCLUDED IN THE DEPRECIATION STUDY?**

19 A. There are five general classes, or functional groups, of depreciable property:
20 Intangible Plant, Gathering Plant, Transmission Plant, Distribution Plant, and
21 General Plant property. Intangible Plant includes software and related assets.
22 Other intangible assets such as organization costs, franchises, and acquisition
23 adjustments were excluded from the study. Gathering Plant assets collect gas from
24 natural gas producers who wish to market their gas. Transmission Plant takes the

1 natural gas using intermediate pressure to send gas to the Distribution System. The
2 Distribution Plant functional group primarily consists of pipes and associated
3 facilities used to distribute gas within the cities served by the Company. General
4 Plant property is not location-specific but is used to support the overall distribution
5 of gas to customers. Fully depreciated compressor station equipment and non-
6 depreciable property, such as land, were excluded from the study.

7 **Q. ARE THE RESULTS OF YOUR DEPRECIATION STUDY REFLECTED**
8 **IN THE TEST YEAR ENDING DECEMBER 31, 2023 COST OF SERVICE**
9 **CALCULATION?**

10 A. Yes. The cost of service calculation for depreciation expense applies my
11 recommended depreciation rates to the adjusted plant balances as of December 31,
12 2023.

13 **Q. WHEN DID THE LAST CHANGE IN THE COMPANY'S DEPRECIATION**
14 **RATES OCCUR?**

15 A. The current depreciation rates were established in Docket No. OS-20-00004347
16 and were based on an amended unanimous settlement agreement between the
17 Company and intervenors in Docket No. OS-20-00004347, and authorized in the
18 Final Order signed by the Commissioners on February 9, 2021.¹

¹ *Statement of Intent of West Texas Gas, Inc. to Increase Gas Utility Rates Within the Unincorporated Areas of Texas*, Docket No. OS-20-00004347 consol. (formerly GUD No. 10998), Final Order (Feb. 9, 2021).

1 **B. Overview of Depreciation Study**

2 **Q. WHAT DEFINITION OF DEPRECIATION HAVE YOU USED FOR**
3 **PURPOSES OF CONDUCTING A DEPRECIATION STUDY AND**
4 **PREPARING YOUR TESTIMONY?**

5 A. The term “depreciation,” as used herein, is considered in the accounting sense; that
6 is, a system of accounting that distributes the cost of assets, less net salvage (if any),
7 over the estimated useful life of the assets in a systematic and rational manner.
8 Depreciation is a process of allocation, not valuation. Depreciation expense is
9 systematically allocated to accounting periods over the life of the properties. The
10 amount allocated to any one accounting period does not necessarily represent the
11 loss or decrease in value that will occur during that particular period. Thus,
12 depreciation is considered an expense or cost, rather than a loss or decrease in value.
13 The Company accrues depreciation based on the original cost of all property
14 included in each depreciable plant account. On retirement, the full cost of
15 depreciable property, less the net salvage amount, if any, is charged to the
16 depreciation reserve.

17 **Q. PLEASE DESCRIBE YOUR APPROACH TO PERFORMING A**
18 **DEPRECIATION STUDY.**

19 A. I conducted the depreciation study in four phases as shown in my Exhibit DAW-1.
20 The four phases are: Data Collection, Analysis, Evaluation, and Calculation.
21 During the initial phase of the study, I collected historical data to be used in the
22 analysis. After the data was assembled, I performed analyses to determine the life
23 and net salvage percentages for the different property groups being studied. As part
24 of this process, I conferred with field personnel responsible for the installation,

1 operation, and removal of the assets to gain their input into the operation,
2 maintenance, and salvage of the assets. The information obtained from field
3 personnel, combined with the study results, was then evaluated to determine how
4 the results of the historical asset activity analysis, in conjunction with the
5 Company's expected future plans, should be applied. Using all of these resources,
6 I then calculated the depreciation rate for each function.

7 **Q. WHAT DEPRECIATION METHODOLOGY DID YOU USE?**

8 A. The straight-line, Equal Life Group ("ELG") remaining-life depreciation system
9 was employed to calculate annual and accrued depreciation in this study. The ELG
10 remaining-life depreciation system was also used to develop the depreciation rates
11 currently in place. The ELG methodology has been an approved depreciation
12 methodology at the Commission for over 20 years.² And it continues to be adopted
13 for Texas natural gas utilities in more recent proceedings.³

14 **Q. HOW WERE DEPRECIATION RATES DETERMINED USING THE ELG**
15 **PROCEDURE?**

16 A. In this procedure, the annual depreciation expense for each group is computed by
17 dividing the original cost of the asset, less allocated depreciation reserve, plus or
18 minus estimated net salvage, by its respective equal life group remaining life. The
19 resulting annual accrual amounts of all depreciable property within a function is

² *Statement of Intent filed by Lone Star Gas Company and Lone Star Pipeline Company, Divisions of Enserch Corporation, and ENSAT Pipeline Company to Increase the Intracompany City Gate Rate Established in GUD 3543, GUD No. 8664, Second Order on Rehearing Nunc Pro Tunc at Finding of Fact ("FoF") No. 92 (Nov. 25, 1997).*

³ *Statement of Intent to Change the Rates CGS and Rate PT Rates of Atmos Pipeline-Texas, GUD No. 10580, Final Order at FoF No. 63 (Aug. 1, 2017); Statement of Intent filed by CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas, to Increase Rates in the Beaumont/East Texas Division, GUD No. 10920 consol., Final Order (Jun. 16, 2020).*

1 accumulated, and the total is divided by the original cost of all functional
2 depreciable property to determine the depreciation rate. The calculated remaining
3 lives and annual depreciation accrual rates are based on attained ages of plant in
4 service and the estimated service life and salvage characteristics of each depreciable
5 group. The computations of the annual functional depreciation rates are shown in
6 Exhibit DAW-1, Appendix A. The remaining life calculations are discussed below
7 and are shown in Exhibit DAW-1, Appendix A-1.

8 C. Service Lives

9 **Q. WHAT IS THE SIGNIFICANCE OF AN ASSET'S USEFUL LIFE IN YOUR**
10 **DEPRECIATION STUDY?**

11 A. An asset's useful life is used to determine the remaining life over which the
12 remaining cost (original cost plus or minus net salvage, minus accumulated
13 depreciation) can be allocated to normalize the asset's cost and spread ratably over
14 future periods.

15 **Q. WHAT ISSUES DID YOU FIND WITH WTGU ASSETS IN ESTIMATING**
16 **SERVICE LIFE?**

17 A. WTGU has added most of its plant through acquisition of assets from other natural
18 gas companies. When assets are acquired by WTGU, the asset is booked with a
19 vintage year of the acquisition date. Acquiring assets a portion of the way through
20 their lives and the recording of the vintages of those assets as the year of acquisition
21 has an impact on the depreciable life of the asset groups. The result is that the asset
22 will have a shorter book life than it will operationally. In other words, assets
23 acquired that are 30 years old will appear to be new in the Company's accounting

1 system. As such a 60-year total life for the assets will only carry a 30-year life for
2 depreciation purposes.

3 **Q. WILL ASSETS FOR WTGU HAVE SERVICE LIVES SIMILAR TO**
4 **OTHER NATURAL GAS COMPANIES?**

5 A. No. The lives of assets for WTGU will be shorter than other natural gas companies
6 who have in-service dates equal to the year of installation. For WTGU, an asset
7 acquired in 2012 will reflect an installation year of 2012, even though the asset may
8 have an original in-service year many years earlier than the acquisition year. With
9 that in mind, the age at acquisition will reduce the life of WTGU assets as compared
10 to the lives of similar assets in other companies where the vintage and the original
11 in-service dates match.

12 **Q. WHAT LIFE DO YOU RECOMMEND FOR THE TWO LARGEST**
13 **ACCOUNTS, 367 (TRANSMISSION MAINS) AND 376 (DISTRIBUTION**
14 **MAINS)?**

15 A. I recommend increasing to a 50-year life and a R2 curve for both Account 367
16 Transmission Mains and Account 376 Distribution Mains. Given the assets are, in
17 reality, much older (20-30 years) than the vintage year, the proposed lives are a
18 reasonable proxy for future expectations in these accounts. For example, the
19 average age of current investment in account 367, using the acquisition year as the
20 vintage, is 11.9 years. Operational per foot data provided by the Company shows
21 the average physical age of existing steel mains is approximately 47 years using a
22 mileage weighting (which will be somewhat longer than a dollar-weighted
23 average). The Operational life of a steel transmission main is longer than 50 years.

1 However, the 50-year proposed average service life incorporates the full period of
 2 time in which the company will have to depreciate the assets on its books before
 3 the assets physically retire. Graphs of the proposed curves are found in Exhibit
 4 DAW-1 in the life analysis section and discussed further for each account.

5 **Q. HOW DID YOU DETERMINE THE AVERAGE SERVICE LIVES FOR**
 6 **EACH ACCOUNT?**

7 A. The establishment of appropriate average service lives for each account was
 8 determined by using the actuarial life analysis method, discussions with Company
 9 personnel, and professional judgment. The remaining life, by account, is calculated
 10 in Appendix A-1 of my Exhibit DAW-1. Graphs and tables supporting the actuarial
 11 analysis along with the chosen Iowa Curves used to determine the average service
 12 lives for analyzed accounts are found in the Life Analysis section of
 13 Exhibit DAW-1.

14 **Q. PLEASE SUMMARIZE THE RESULTS OF THE WTGU STUDY WITH**
 15 **RESPECT TO AVERAGE SERVICE LIVES.**

16 A. Table 1 below shows the existing and proposed average service lives and selected
 17 curve for each account.

Account	Description	Existing		Proposed	
		Life	Curve	Life	Curve
303	Intangible Plant	17	SQ	15	SQ
332	Field Lines	45	R3	45	R3
334	Field Measuring & Regulating Equip	36	R4	36	R4
365.2	Land Rights	45	SQ	45	SQ
367	Transmission Mains	45	R2	50	R2
369	Measuring and Regulating Equipment	40	R4	40	R4
369.1	Meters and Regulators	40	R4	40	R4
371	Other Equipment	20	R5	15	R4
376	Distribution Mains	45	R3	50	R2
378	Distribution Measuring and Regulating Equipment	25	R3	36	R5

Account	Description	Existing		Proposed	
		Life	Curve	Life	Curve
378.1	Meters			20	R2
387	Other Equipment	23	S4	23	S4
389	General Plant Land Rights	45	SQ	50	SQ
390	Structures and Improvements	25	R2.5	50	R0.5
391	Office Furniture and Equipment	20	SQ	20	SQ
391.1	Computer Equipment	5	SQ	5	SQ
392	Transportation Equipment	8	L2	6	L2
394	Tools, Shop, and Garage Equipment	25	L2	25	SQ
396	Power Operating Equipment			20	L2
397	Communication Equipment	15	SQ	12	SQ
398	Miscellaneous Equipment	15	SQ	15	SQ

1 **Q. WHAT PROCESS HAVE YOU UNDERTAKEN TO GIVE EFFECT TO**
2 **BOTH HISTORICAL DATA AND COMPANY-SPECIFIC**
3 **EXPECTATIONS IN DEVELOPING YOUR SERVICE LIFE**
4 **RECOMMENDATIONS?**

5 A. In order to achieve a reasonable balance between these critical components of the
6 life analysis, I evaluated the statistical historical data and then applied informed
7 judgment to make the most appropriate service life selections. The objective in any
8 depreciation study is to project the remaining cost (installation, material, and
9 removal cost) to be recovered and the remaining periods over which to recover the
10 costs. This necessarily requires that the service life selections reflect both the
11 Company's historic experience and its current expectations of asset lives. In order
12 to understand the Company's expectations regarding asset lives, I interviewed
13 Company engineers working in both operations and maintenance to confirm the
14 historical activity and indications, current and future plans, expectations, and the
15 applicability to the future surviving assets. The interview process provides
16 important information regarding changes in materials, operation and maintenance,

1 as well as the Company's current expectation regarding the service life of the assets
2 currently in use. This information is then considered along with the historical
3 statistical data to develop the most reasonable and representative expected service
4 lives for the Company's assets. The result of this analysis is reflected in the service
5 life recommendations set forth in my depreciation study.

6 **Q. AS PART OF YOUR DEPRECIATION ANALYSIS, HAVE YOU TAKEN**
7 **ANY ACTION TO PROPERLY ALIGN WTGU'S DEPRECIATION**
8 **RESERVE WITH THE LIFE CHARACTERISTICS OF THE**
9 **INTANGIBLE, GATHERING, DISTRIBUTION, TRANSMISSION AND**
10 **GENERAL PLANT FUNCTIONS?**

11 A. Yes. In the process of analyzing the Company's depreciation reserve, I observed
12 that the depreciation reserve positions of the various accounts needed to be re-
13 balanced based on my recommended service lives. To allow the relative reserve
14 positions of each account within a function to mirror the life characteristics of the
15 underlying assets, I reallocated the depreciation reserves for all accounts within
16 each function.

17 **Q. WHY IS IT NECESSARY TO RE-ALLOCATE THE RESERVES TO**
18 **ACCOUNT FOR ANY RECOMMENDED CHANGES IN THE LIFE**
19 **PARAMETERS?**

20 A. The purpose of a depreciation study, and specifically the remaining life technique
21 used in this case, is to calculate accrual rates that will allow the Company to recover
22 the remaining balance of its investment in plant over the remaining lives of the un-
23 depreciated assets in its invested plant balance. When new service lives or net

1 salvage ratios are adopted as part of a new depreciation study or operational
2 changes occur over time that affect the balances in the reserve, the reserve for
3 individual accounts can become out of sync with the underlying assets. Re-
4 allocation is performed to re-spread the reserves between accounts within a function
5 to bring the reserves for each account back into parity with each other. This brings
6 the undepreciated plant balances associated with each account back in line so that
7 each account contributes the appropriate level of depreciation expense in order to
8 fully depreciate the assets at the end of the recommended useful life.

9 **Q. IS RESERVE RE-ALLOCATION CONSISTENT WITH STANDARD**
10 **DEPRECIATION PRACTICE AND METHODOLOGIES YOU HAVE**
11 **USED TO CONDUCT DEPRECIATION STUDIES BEFORE THIS**
12 **COMMISSION IN THE PAST?**

13 A. Yes. The practice of depreciation reserve allocation is widely recognized and
14 commonly practiced as part of a comprehensive depreciation study for the purposes
15 of setting regulated rates where changes in service lives result in an imbalance
16 between the theoretical and book reserve.⁴ With respect to WTGU, my
17 depreciation study demonstrates that there have been significant changes in the life
18 of the property since the last depreciation study.⁵ These changes have created
19 imbalances between the theoretical and the book reserve for various accounts
20 within each function making the reallocation of the depreciation reserve appropriate
21 in this instance.

⁴ *Public Utility Depreciation Practices*, National Association of Regulatory Utility Commissioners (“NARUC”) (1968), at 48; *Public Utility Depreciation Practices*, NARUC (1996), at 188.

⁵ Docket No. OS-20-00004347 was based on plant activity through year end 2019. This study is based on plant activity through year end 2023, thus including an additional four years of data.

1 **Q. DOES THE REALLOCATION CHANGE THE AMOUNT OF THE BOOK**
2 **RESERVE?**

3 A. No. The recorded book reserve is maintained at a functional level. The reallocation
4 occurs within the accounts of each respective function.

5 **Q. WILL THE COMPANY RECORD THE REALLOCATED RESERVES ON**
6 **ITS BOOKS?**

7 A. Yes, the book reserves will be reallocated at the time the Commission-approved
8 rates and parameters go into effect. This timing ensures that the Commission's
9 decisions on the life, dispersion and net salvage parameters are fully reflected in
10 the Company's books and records.

11 **D. Net Salvage**

12 **Q. WHAT IS NET SALVAGE?**

13 A. As discussed more fully in Exhibit DAW-1, net salvage is the difference between
14 the gross salvage (what is received in scrap value for the asset when retired) and
15 the removal cost (cost to remove and dispose of the asset). Salvage and removal
16 cost percentages are calculated by dividing the current cost of salvage or removal
17 by the original installed cost of the asset. When salvage exceeds removal cost
18 (positive net salvage), the net salvage reduces the amount to be depreciated over
19 time. When removal cost exceeds salvage (negative net salvage), the negative net
20 salvage increases the amount to be depreciated.

21 **Q. DOES WTGU HAVE ANY NET SALVAGE REFLECTED IN ITS**
22 **EXISTING DEPRECIATION RATES?**

23 A. Yes, but only for Account 392 Transportation Equipment. Currently, the Company
24 is booking removal cost as part of the cost of a new asset. We recommend that

1 WTGU change its accounting practice and record cost of removal and gross salvage
2 to the depreciation reserve, similar to other regulated natural gas utilities. The
3 Company has consistently recorded net salvage costs for Account 392
4 Transportation Equipment. Given the current accounting practice for WTGU, this
5 study recommends 0% net salvage at this time for all accounts except Account 392
6 and Account 396, which reflect a positive gross salvage.

7 **Q. WHAT ARE YOUR NET SALVAGE RECOMMENDATIONS IN THIS**
8 **PROCEEDING?**

9 A. As mentioned above, there is no cost of removal or salvage being recorded in the
10 majority of the accounts. However, I have recommended retaining a positive 10%
11 net salvage for Account 392 Transportation Equipment and recommend using the
12 same positive 10% for newly created Account 396 Power Operating Equipment.
13 The detailed analysis of historical net salvage activity in Account 392 is shown in
14 Appendix D of Exhibit DAW-1 and discussed in the Net Salvage section of the
15 report.

16 **IV. CONCLUSION**

17 **Q. DO YOU HAVE ANY CONCLUDING REMARKS?**

18 A. Yes. The depreciation study and analysis performed under my supervision fully
19 support setting depreciation rates at the level I have indicated in my testimony and
20 exhibits. The Company should continue to periodically review the annual
21 depreciation rates for its property. In this way, all customers will be charged for
22 their appropriate share of the capital expended for their benefit. The depreciation
23 study included as Exhibit DAW-1 describes the extensive analysis performed and
24 the resulting rates that are now appropriate for Company property. The Company's

1 depreciation rates should be set at my recommended amounts in order to recover
2 the Company's total investment in property over the estimated remaining life of the
3 assets.

4 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

5 A. Yes, it does.

STATE OF TEXAS §
 §
COUNTY OF COLLIN §

AFFIDAVIT OF DANE A. WATSON

BEFORE ME, the undersigned authority, on this day personally appeared Dane A. Watson, who having been placed under oath by me did depose as follows:

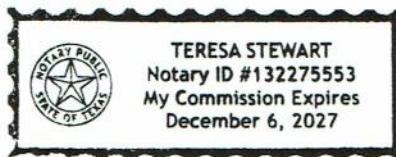
1. “My name is Dane A. Watson. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. I am a Partner of Alliance Consulting Group.
2. I have prepared the foregoing direct testimony and the information contained in this document is true and correct to the best of my knowledge.”

Further affiant sayeth not.

Dane A. Watson
Dane A. Watson

SUBSCRIBED AND SWORN TO BEFORE ME by the said Dane A. Watson on this 9th day of July 2024.

Teresa Stewart
Notary Public, State of Texas



WEST TEXAS GAS

**Book Depreciation Accrual
Rate Study
At December 31, 2023**



WEST TEXAS GAS DEPRECIATION RATE STUDY

EXECUTIVE SUMMARY

West Texas Gas (“WTG” or “Company”) engaged Alliance Consulting Group to conduct a depreciation study of the Company’s Gas Intangible, Gathering, Transmission, Distribution, and General utility plant depreciable assets as of December 31, 2023. This study incorporates the same group accounting method used in the previous study and approved in open settlement OS-20-00004347, formerly GUD No. 10998.

I conducted this study using a traditional depreciation study approach for life and net salvage adjusted to take into account that many of the Company’s assets were recently acquired and the original in service date was not available upon acquisition. The fixed assets were recorded using the acquisition date as the vintage of investment. I used the straight line, equal life group, remaining life depreciation system. This methodology is a standard methodology used and adopted by the Railroad Commission of Texas as precedent for more than 20 years.

This study recommends an overall decrease of \$769 thousand compared to the annual depreciation expense calculated using the existing depreciation rates. The primary drivers of this change are changes to the average service lives, including the increase in average service life in the Company’s largest account, Account 378 Distribution Mains, mitigated by the historical accumulated depreciation reserve position in several accounts. A detailed comparison of the existing versus proposed annual accrual rates and amounts is shown in Appendix B.

**WEST TEXAS GAS
DEPRECIATION RATE STUDY
AT December 31, 2023**

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PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable gathering, transmission, distribution, and general utility property as recorded on the books of West Texas Gas (“WTG” or “Company”) as of December 31, 2023. The depreciation rates are designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of West Texas Gas’ property on a straight-line basis. Fully depreciated compressor station equipment and non-depreciable assets, such as land, were excluded from this study.

West Texas Gas provides local gas distribution service to customers in Texas and Oklahoma. West Texas Gas headquarters are located at 303 Veterans Airpark Ln, Suite 5000, Midland, Texas 79705. WTG has core businesses in natural gas distribution operations, natural gas transmission services, gas gathering/processing, and natural gas liquids transmission services. WTG owns and operates approximately 6,000 miles of Natural Gas Distribution mainlines and serves approximately 29,000 customers within the states of Texas and Oklahoma. WTG also owns and operates approximately 752 miles (non-contiguous) of Natural Gas Transmission pipelines and 143 miles of gathering pipelines within the states of Texas and Oklahoma.

STUDY RESULTS

Recommended depreciation rates for West Texas Gas Texas depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual for Intangible, Gathering, Transmission, Distribution and General plant of approximately \$5.9 million, which is a decrease of \$769 thousand when compared to the annual accrual using the existing depreciation rates. These accruals are based on WTG Texas' depreciable investment at December 31, 2023. A table summarizing the proposed versus existing accrual by function is shown below.

Utility Function	Plant Balance at 12/31/2023	Existing Annual Accrual	Proposed Annual Accrual	Difference
Total Intangible Plant	\$ 378,315	\$ -	\$ -	\$ -
Total Gathering Plant	3,148,811	-	-	-
Total Transmission Plant	52,329,558	1,317,333	1,165,158	(152,176)
Total Distribution Plant	176,288,117	4,609,377	4,074,103	(535,274)
Total General Plant	16,317,866	740,142	677,272	(62,871)
Amortized Reserve Difference			(18,292)	(18,292)
Grand Total	\$ 248,462,667	\$ 6,666,853	\$ 5,898,241	\$ (768,612)

Appendix A shows the detailed computation of the proposed annual accrual rates and amounts for each account. Appendix A-1 shows the calculation of the remaining life for each account. Appendix B shows a comparison of the current versus proposed annual accrual amounts and rates. Appendix C shows the life parameters for each account. Appendix D shows the Transportation net salvage analysis.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. At retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

Basis of Depreciation Estimates

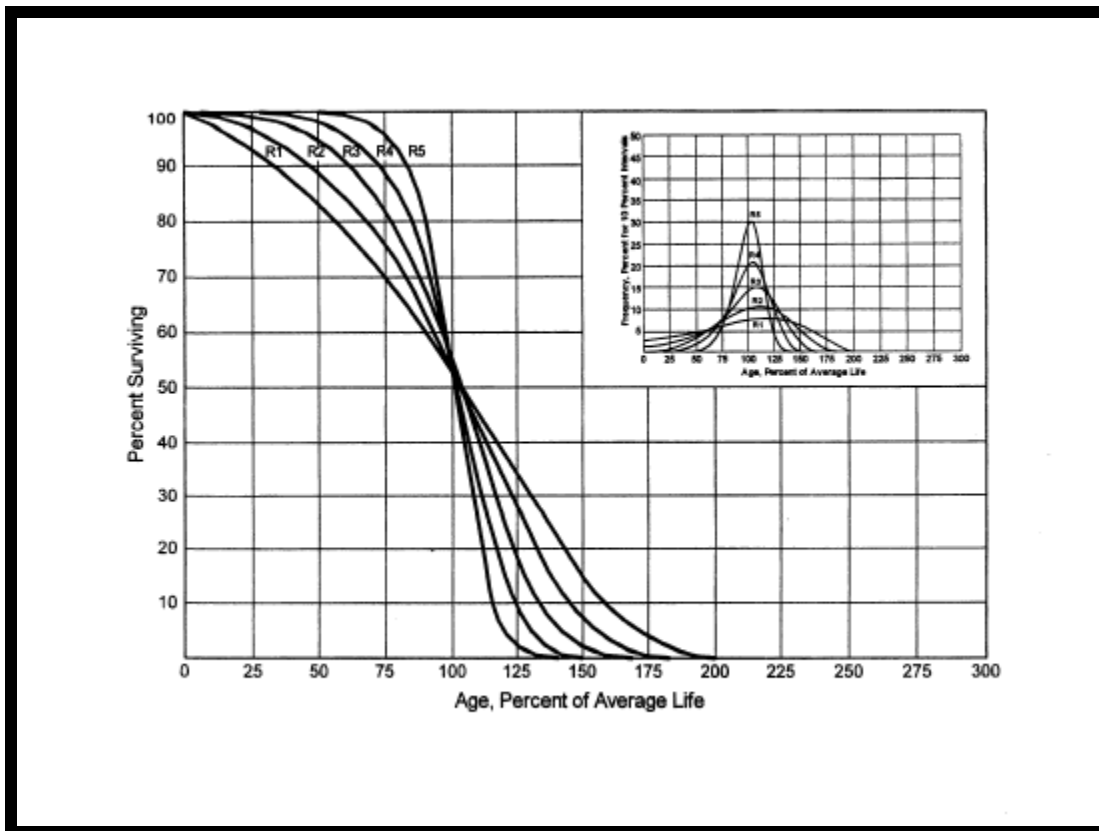
Annual and accrued depreciation were calculated in this study by the straight-line, equal life group, remaining-life depreciation system. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset group (less allocated depreciation reserve less estimated net salvage) by its respective average remaining life. The resulting annual accrual amounts were divided by the original cost of the depreciable property in each account to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group, and were computed in a direct weighting by multiplying each vintage or account balance times its remaining life and dividing by the plant investment in service at December 31, 2023. The computations of the annual depreciation rates are shown in Appendix A, and the weighted remaining life calculations are also shown in Appendix A-1. Actuarial Analysis was used with each account within a function where sufficient activity occurred within the account, and judgment was

used to some degree on all accounts.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual assets within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by comparing actual experience against various survivor curves. A survivor curve represents the percentage of property remaining in service at various age intervals. The most widely used set of representative survivor curves are the Iowa Survivor Curves (Iowa Curves). The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the twentieth century. Through common usage, revalidation, and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.

There are four families in the Iowa Curves which are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. The four families are designated as "R"— Right, "S" — Symmetric, "L" — Left, and "O" — Origin Modal. First, for distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of "R" moded curves is shown below.



Second, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. Third, an "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. Fourth, a special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

For Intangible, Gathering, Transmission, Distribution, and General

Property accounts, a survivor curve pattern was selected based on analyses of historical data, as well as other factors, such as general changes relevant to the Company's operations. The blending of judgment concerning current conditions and future trends, along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern. Iowa Curves were used to depict the estimated survivor curves for each account.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. Historical data from WTG's Texas and Oklahoma operations were combined for life analysis. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Many accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. Matching data in observed life tables for each experience and placement band to an Iowa Curve requires visual examination. As stated in Depreciation Systems by Wolf and Fitch, "the analyst must decide which points or sections of the curve should be given the most weight. Points at the end of the curve are often based on fewer exposures and may be given less weight than

those points based on larger samples” (page 46). Some analysts chose to use mathematical fitting as a tool to narrow the population of curves using a least squares technique. Use of the least squares approach does not imply a statistical validity, however, because the underlying data does not meet criteria for independence between vintages and the same average price for property units through time. Thus, Depreciation Systems cautions, “... the results of mathematical fitting should be checked visually and the final determination of best fit made by the analyst” (page 48). This study uses the visual matching approach to match Iowa Curves, since mathematical fitting produces theoretically possible curve matches. Visual examination and experienced judgment allow the depreciation professional to make the final determination as to the best curve type. Detailed information for each account is shown later in this study and in workpapers.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. In this depreciation study, judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, property mix in accounts or a multitude of other considerations that affect the analysis (potentially in various directions), judgment is used to take all of these considerations and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one consideration in these cases may have a substantial impact on the analysis, but overall, the collective effect of these considerations may shed light on the use and characteristics of assets. Judgment may also be defined as deduction,

inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. The establishment of appropriate average service lives and retirement dispersions for the Intangible, Gathering, Transmission, Distribution and General accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed while conducting actuarial life analysis. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Equal Life Group Depreciation

The Company's existing depreciation rates were calculated using the equal life group procedure. The Railroad Commission of Texas has recognized the precedent of the equal life group ("ELG") depreciation procedure since the late 1990s. Texas gas distribution companies have approved depreciation rates based on the ELG procedure. This study continues to use the ELG depreciation procedure to group the assets within each account. After an average service life and dispersion were selected for each account, those parameters were used to estimate what portion of the surviving investment of each vintage was expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ELG groups are defined by their respective account dispersion, life, and salvage estimates. A straight-line rate for each ELG group is computed and accumulated across each vintage. The resultant rate for each ELG group is designed to recover all retirements less net salvage as each vintage retires. The ELG procedure recovers net book cost over the life of each ELG group rather than averaging many components. It also closely matches the concept of component or item accounting found in accounting textbooks.

Theoretical Depreciation Reserve

This study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The equal life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each-year until all property within the vintage is retired. Estimated average service lives and dispersion determine the amount within each equal life group. The equal life group-remaining-life theoretical reserve ratio (RRELG) is calculated as:

$$RRELG = 1 - \frac{(ELG \text{ Remaining Life})}{(ELG \text{ Life})} * (1 - \text{Net Salvage Ratio})$$

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. After the first three stages were complete, the fourth phase began. This phase involved the calculation of depreciation rates and documenting the corresponding recommendations.

During the Phase I data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting it and comparing to multiple financial system sources: Fixed Asset System (continuing property ledger) and the General Ledger. This data was validated against historical data from prior periods, historical general ledger sources, and through field personnel discussions. This data was reviewed extensively so that it could be put in the proper format for a depreciation study. Also as part of the Phase I data collection process, discussions were conducted with engineers and field operations personnel to obtain information that would be helpful in formulating life recommendations in this study. One of the most important elements in performing a proper depreciation study is to understand how the Company utilizes assets and the environment in which those assets are used. Understanding industry and geographical norms for mortality characteristics are important factors in selecting life and salvage recommendations; however, care must be used not to apply them rigorously to any particular company since no two companies would have the same exact forces of retirement acting upon their assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is helpful when evaluating the output from the life program in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion portions of the Life Analysis section and also in the workpapers. In addition, Alliance personnel possess a significant understanding

of the property and its forces of retirement due to years of day-to-day exposure to gas utility property and its operation. Phase 2 is where the actuarial life analysis was performed. Phase 2 and Phase 3 (to be discussed in the next paragraph) overlap to a significant degree. The detailed property records information was used in Phase 2 to develop observed life tables for life analysis and actuarial graphs and statistics. This information was then carried forward into Phase 3 for the evaluation process.

Phase 3 is the evaluation process, which synthesized analysis, interviews, and operational characteristics into a final selection of asset lives. The historical analysis from Phase 2 was further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. The preliminary results were then reviewed and discussed with accounting and operations personnel. Phases 2 and 3 validated the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1¹ documents the steps used in conducting this study. Depreciation Systems² on page 289 documents the same basic processes in performing a depreciation study.

¹ Public Utility Finance & Accounting, A Reader (Modified)

² Depreciation Systems, by Dr. Frank K. Wolf and Dr. W. C. Fitch, Iowa State Press, 1994, p. 289.

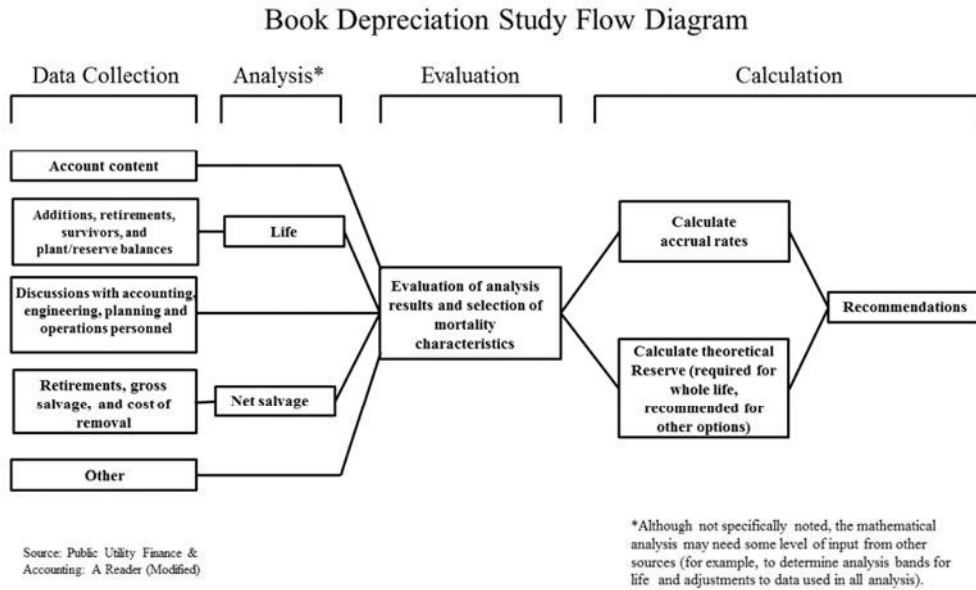


Figure 1

WTG DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation

Annual depreciation expense amounts for the depreciable property accounts of West Texas Gas were calculated by the straight-line, equal-life group, remaining-life system. With this approach, remaining lives were calculated according to standard ELG group expectancy techniques, using the Iowa Survivor Curves noted in the calculation. For each plant account, the difference between the surviving investment, adjusted for estimated net salvage and the allocated book depreciation reserve, was divided by the average remaining life to yield the annual depreciation expense. These calculations are shown in Appendix A.

Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group was based on engineering judgment that incorporated available accounting information analyzed using the actuarial life analysis, taking into account that many of the assets were acquired and recorded in the fixed asset records with the vintage being the acquisition year. This accounting approach has the effect of requiring shorter depreciable lives than would normally be expected for some asset groups since an asset at "age 0" may already be 30 years old or more. After establishment of appropriate average service lives and retirement dispersion, remaining life was computed for each account. The theoretical depreciation reserve with zero net salvage (used in calculating remaining life) was calculated using theoretical reserve ratios as defined in the theoretical reserve portion of the general discussion section. The difference between plant balance and theoretical reserve was then spread over the ELG depreciation accruals. After accumulating the ELG accruals across each vintage, the annual accrual was divided into the net balance to compute remaining life. Details of the theoretical reserve computations, ELG accruals, and remaining life are found by account within each function in the study workpapers.

LIFE ANALYSIS

The retirement rate, actuarial analysis method was applied to all accounts. Vintage balances and historical transactional data were combined for the Texas and Oklahoma assets operated by the Company for life analysis. For each account where sufficient retirement data exists, an actuarial analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Curves to obtain the most appropriate match. The selected life and curve, by account, is shown in Appendix C. The remainder of placement and experience band analyses is contained in the workpapers.

For each account on the overall band (i.e., placement from earliest vintage year through 2023) and experience band from earliest available experience year (1998) through 2023, the most recently approved survivor curves were used as a starting point. Then, using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (e.g., L, S, or R) as an obviously better match than others. The next step is to determine the most appropriate life using that dispersion pattern. Generally, the goal of visual matching is to minimize the differential between the observed life table and Iowa Curve in top and mid-range of the plots.

Actuarial analysis was available from 1998-2023. No history was available prior to that period, so the historic life analysis was limited for the longest-lived accounts. With limited retirement history, interviews provided great insight into the Company's operations and the impact that those operations are expected to have on the service lives of the assets used to provide utility service. The acquisition of assets a portion of the way through their lives and the recording of the vintages of those assets as the year of acquisition affect the life of the asset groups. In other words, assets acquired that are 30 years old will appear to be new in the Company's accounting system. As such a 75-year total life for the assets will only carry a 45-year life for depreciation purposes. This information in conjunction with all other factors is used to select the most appropriate life and curve for each asset

group.

Intangible Plant Account 303
Account 303 Intangible Plant (15 SQ)

This account includes the cost of intangible assets such as software. There is approximately \$378 thousand of current investment in this account. The current life for this account is 17 years with a SQ dispersion. The current investment is fully depreciated and consists primarily of billing software. There has been very limited retirement activity since the prior study. Operational subject matter experts estimate new software assets, such as ERP systems to have an operational life of 15 years. Given the age of the existing assets, mix of assets in this account, and the estimated life of future software assets, this study recommends decreasing to a 15-year life and SQ dispersion for this account.

Transmission Plant Accounts 365.2 - 371

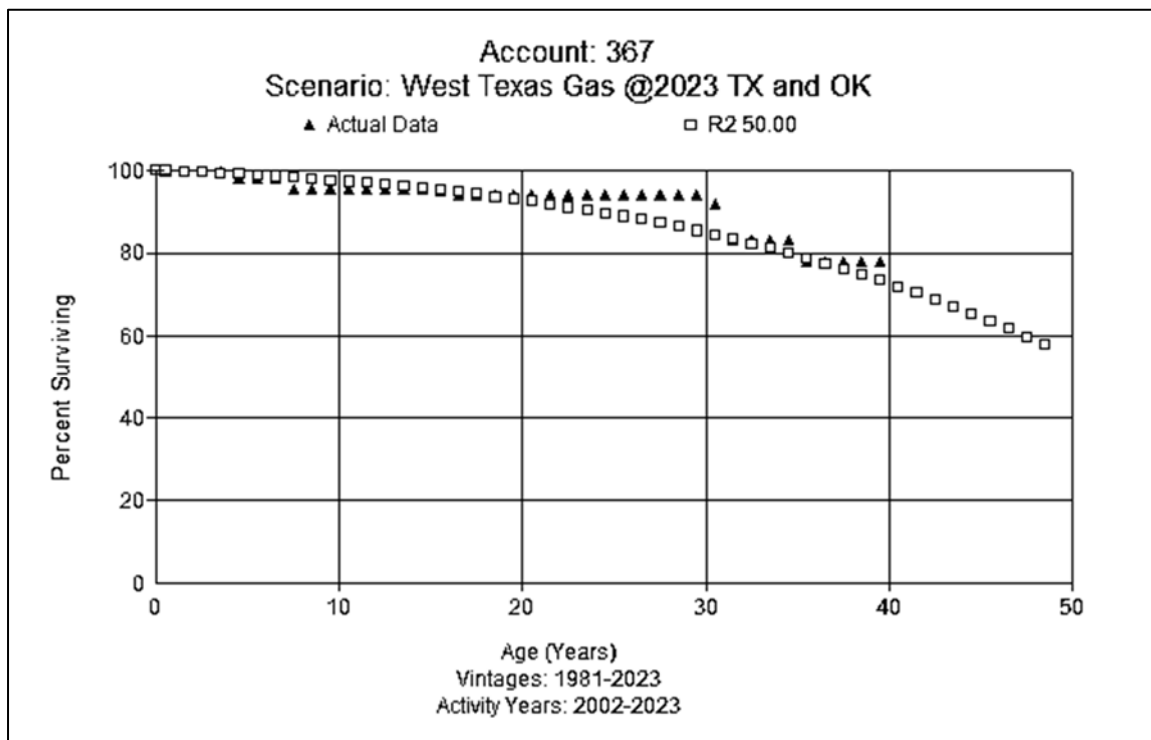
Account 365.2 Land Rights (45 SQ)

This account includes the cost of land rights used in the transmission system. There is approximately \$5.4 million of current investment in this account. The current life for this account is 45 years with a SQ dispersion. Insufficient data exists to perform a life analysis on this account. Based on the proposed life for Account 367 Transmission Mains and the fact that acquisitions were recorded on the Company's books with a vintage of the year of acquisition, this study recommends retaining the existing 45-year life and SQ dispersion curve for this account.

Account 367 Transmission Mains (50 R2)

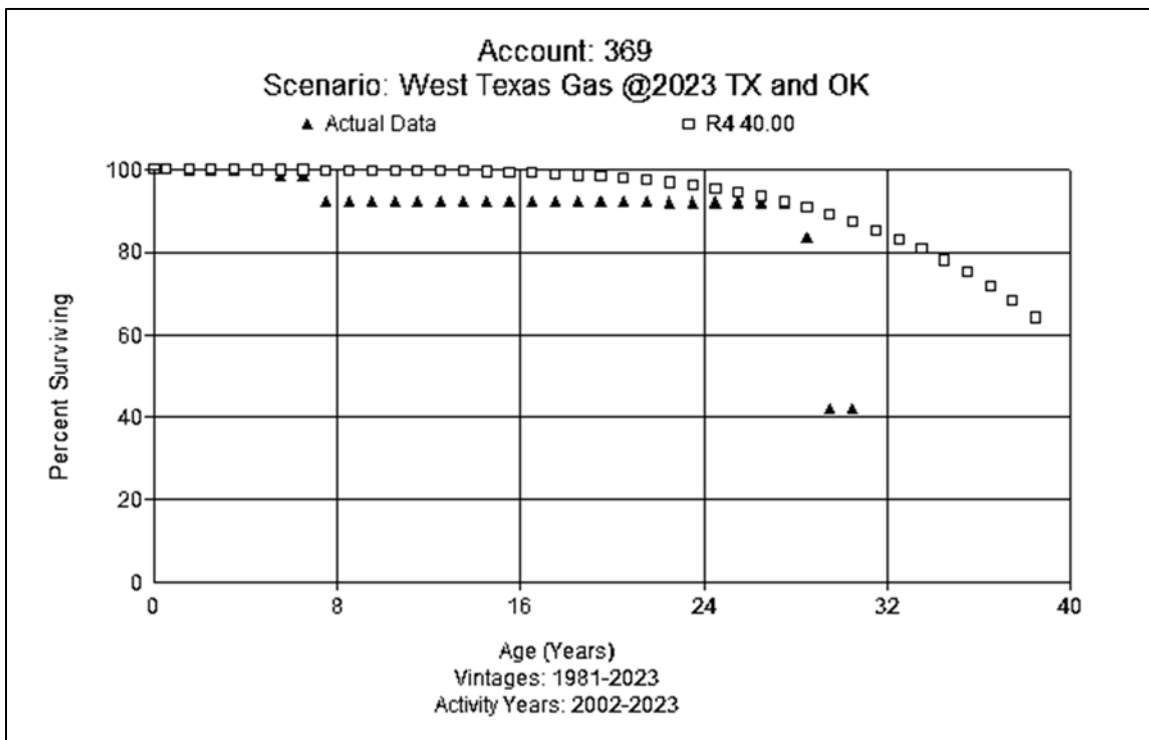
This account includes transmission mains and related assets. There is approximately \$45.3 million of current investment in this account. The current life for this account is 45 years with an R2 dispersion. WTG's assets have been acquired from a variety of sources. When an asset has been acquired it is booked

with the vintage as acquisition date rather than the true age of the asset. This impacts the depreciable life of WTG’s assets. The average age of current investment in this account, using the acquisition year as the vintage, is 11.9 years. Operational per foot data provided by the Company shows the average physical age of existing steel mains is approximately 48 years. Nearly all of the existing transmission mains are steel. The Company recently replaced approximately 40 miles of the Dalhart system in 2014. Operational personnel estimate the mains being replaced were originally installed in the 1940’s and 1950’s, making them more than 70 years old at the time of replacement. The new protected steel mains being installed are estimated to have an operational life of 80 years. Based on life analysis, judgment and the fact that acquisitions were recorded on the Company’s books with a vintage of the year of acquisition, this study recommends increasing to a 50-year life and an R2 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.



Account 369 Measuring and Regulating Equipment (40 R4)

This account includes transmission measuring and regulating station equipment. There is approximately \$1.1 million of current investment in this account. The current life for this account is 40 years with an R4 dispersion. The Company has rebuilt several stations over the last five years and more than half of the current investment relates to newly installed equipment. Control valves, analyzers, and technical analytical equipment, which have a shorter useful life, have been replaced and recorded as Operations and Maintenance expense. Operational subject matter experts anticipate the operational life of the newly installed transmission M&R equipment to be longer than the existing distribution M&R equipment. Based on life analysis, judgment, and the fact that acquisitions were recorded on the Company’s books with a vintage of the year of acquisition, this study recommends retaining the existing 40-year life and R4 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.

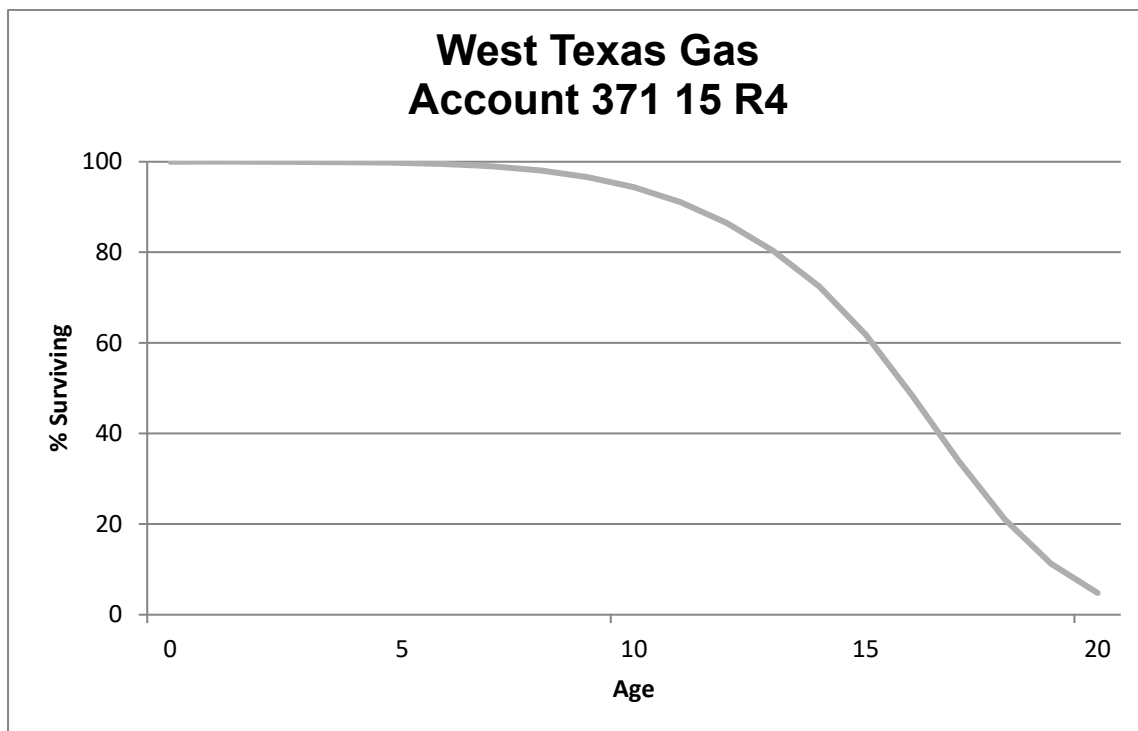


Account 369.1 Transmission Meters (40 R4)

This subaccount includes transmission meters. There is approximately \$362 thousand of current investment in this account. The current life for this account is 40 years with an R4 dispersion. Insufficient data exists to perform a life analysis on this account. The Company has meters at both the town border stations and on customer premises. The existing meters were purchased new, as opposed to other assets in the Company being acquired. WTG is currently replacing meters at between 15 and 20 years. At the time of replacement, the meter is tested, rebuilt or recalibrated, and then reinstalled. No retirement is currently being recorded in fixed assets at the time of the refurbishment. Essentially, the meter is going through two life-cycles being rebuilt and reinstalled before it is retired. Based on the existing lifecycle of the meters, information from Company personnel, and judgement, this study recommends retaining the existing 40-year life and R4 dispersion for this account.

Account 371 Other Equipment (15 R4)

This account includes miscellaneous equipment used in transmission operations not booked in the other transmission accounts. There is approximately \$224 thousand of current investment in this account. The current life for this account is 20 years with an R5 dispersion. Assets in this account include handheld meter equipment, cathodic protection equipment, Itron accessories, and radios. The small electronic equipment in this account has a relatively short life due to changes in technology. Based on life analysis, the mix of assets in this account, and judgment, this study recommends decreasing to a 15-year life and an R4 dispersion curve for this account. A graph of the proposed dispersion curve is shown below.



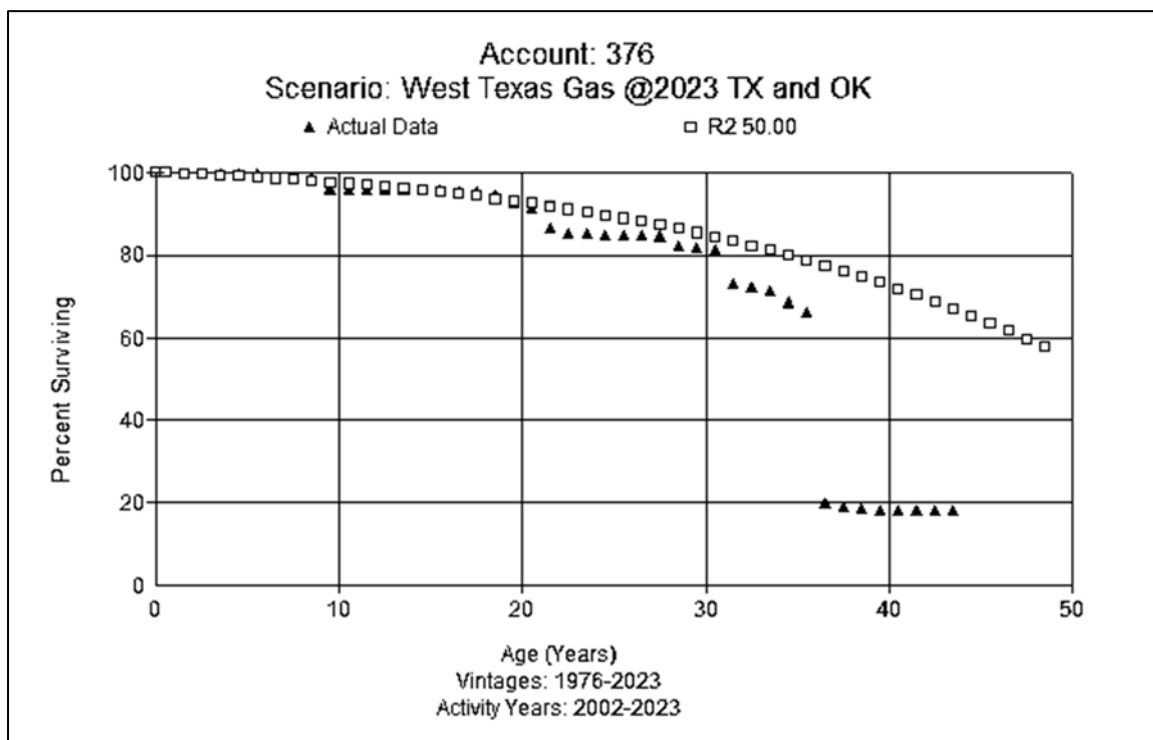
Distribution Plant Accounts 376 - 387

Account 376 Mains (50 R2)

This account includes distribution mains and related assets including services, riser bars, meters, and the meter loop. There is approximately \$167.9 million of current investment in this account. The current life for this account is 45 years with an R2 dispersion. The Company operates both plastic and steel distribution mains. WTG's assets have been acquired from a variety of sources. When an asset has been acquired it is booked with the vintage as the acquisition date rather than the original installation date of the asset. This impacts the depreciable life of WTG's assets. The average age of current investment, using the acquisition date to assign a vintage, is 10.03 years. Operational per foot data provided by the Company shows the average physical age of existing steel mains is 52 years and plastic mains is approximately 45 years.

WTG implemented a Distribution Integrity Management Program (DIMP) in

2012 to replace 340 thousand feet of suspect pipe over the next 20 years. Operational subject matter experts estimate the age of the mains being replaced for DIMP is approximately 60 years old. Actuarial analysis shows the existing 45-year life is a better fit. However, more than half of the current investment consists of new main replacements installed since 2013. As the Company continues to add new investment in this account, the average service life is expected to gradually increase over time. Based on life analysis, judgement, and the fact that acquisitions were recorded on the Company's books with a vintage of the year of acquisition, this study recommends increasing to a 50-year life and an R2 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.

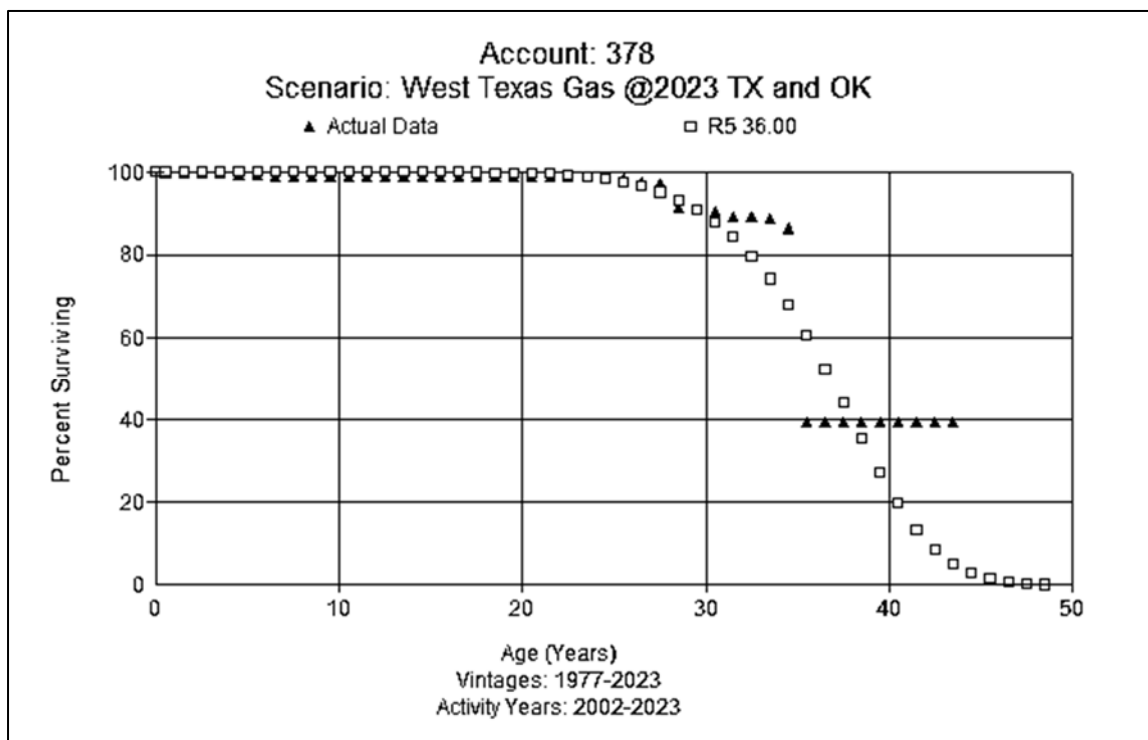


Subaccounts Created for Account 378 Measuring and Regulating Station Equipment

The average service lives of the assets within this account are distinctly different for Measuring and Regulating Station Equipment versus the Meters. WTG is currently using a 36-year life for all assets in Account 378. The Company has decided to create a new subaccount for future investment relating to meters to record these assets with distinct service lives separately. The timing of this filing and limited resources did not allow the Company to split current investment. Therefore, this study factors in information provided by Company subject matter experts and analyzes the limited historical retirement activity for the current mix of assets within Account 378 – M & R Station Equipment and proposes to create Account 378.1 – Meters to record future investment.

Account 378 Measuring and Regulating Station Equipment (36 R5)

This account consists of meters, gauges, and other equipment used in measuring and regulating gas in connection with distribution system operations other than the measurement of gas deliveries to customers. There is approximately \$7.7 million of current investment in this account. The current life for this account is 36 years with an R5 dispersion. WTG currently operates both district regulating and city gate stations. Company subject matter experts estimate the town border station equipment has an operational life between 40 and 50 years. Nearly half of the existing investment relates to meters, and the Company is currently experiencing a shorter life for the meters than other measuring and regulating equipment. Based on life analysis, the mix of assets in this account, and judgment, this study recommends retaining the existing 36-year life and R5 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.



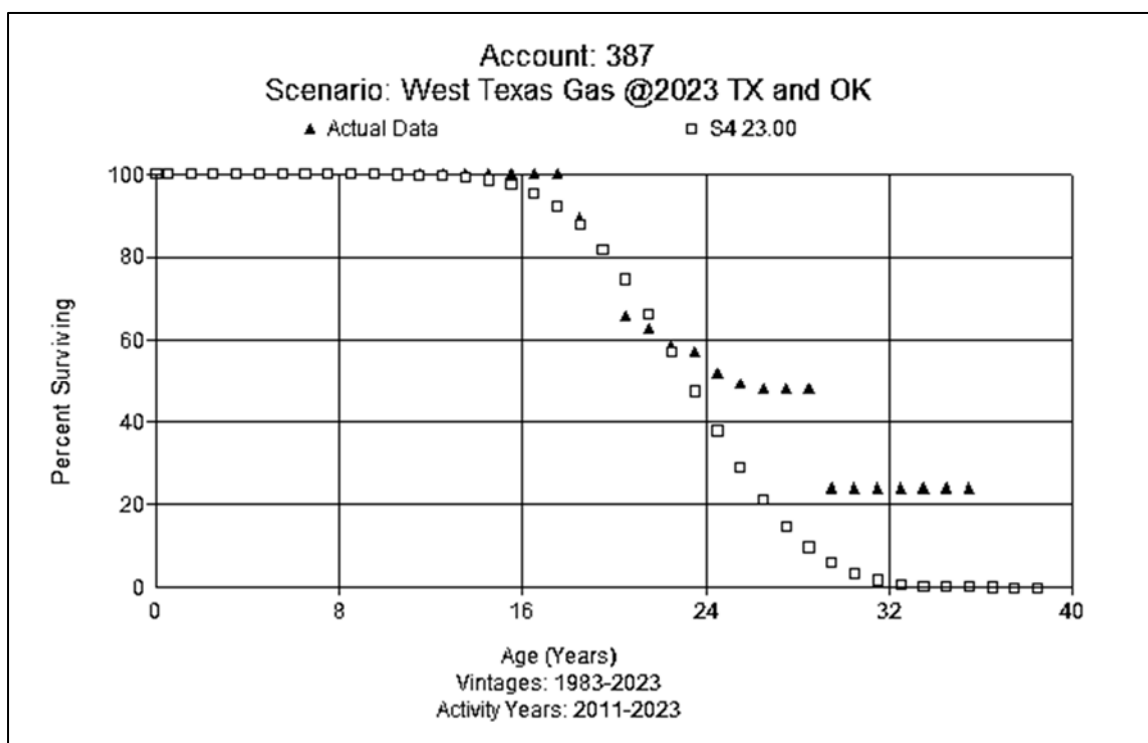
Account 378.1 Meters (20 R2)

This new subaccount is being created to track future investment related to meters separately from other regulating station equipment. Meters have a shorter operating life than other M & R station equipment. Company subject matter experts estimate the meters have an operational life around 20 years. Approximately 10 percent of the current meters are ERTS. The Company is starting to experience more battery failures on meters installed in 2010. The battery replacements are currently being expensed. experiencing a shorter life for Based on meters having a shorter life than other measuring and regulating equipment, this study recommends using a 20-year life and R5 dispersion curve for future investment in this new subaccount.

Account 387 Other Equipment (23 S4)

This account includes the cost of other equipment including Itron meter

reading equipment, a tapping machine, leak detectors, and other related equipment used for distribution operations. There is approximately \$688 thousand of current investment in this account. The current life for this account is 23 years with an S4 dispersion. The Company is currently experiencing a 10-year operating life for meter readers. Rectifiers are being replaced around 40 years and the electronic temperature correctors are operational for about 20 years. The tapping machine is estimated to have a useful life of at least 30 years. Based on life analysis, the mix of assets in this account, and judgment, this study recommends retaining the existing 23-year life and an S4 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.



General Plant Accounts 389 - 398

General Plant Depreciated Accounts

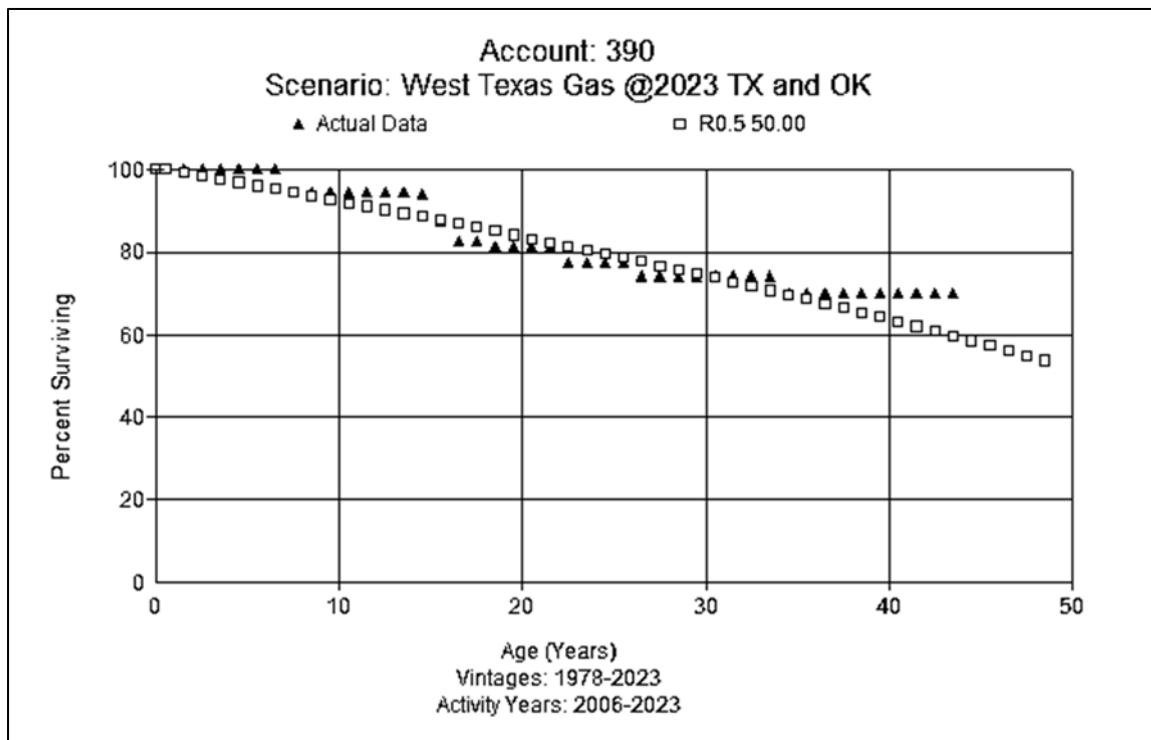
Account 389 Land Rights (50 SQ)

This account includes the cost of land rights associated with general plant

facilities. There is approximately \$6.3 million of current investment in this account. The current life for this account is 45 years with an SQ dispersion. There is insufficient data to analyze this account. Based on the proposed life for Account 390 Structures and Improvements and the fact that acquisitions were recorded on the Company's books with a vintage of the year of acquisition, this study recommends increasing to a 50-year life and SQ dispersion curve for this account.

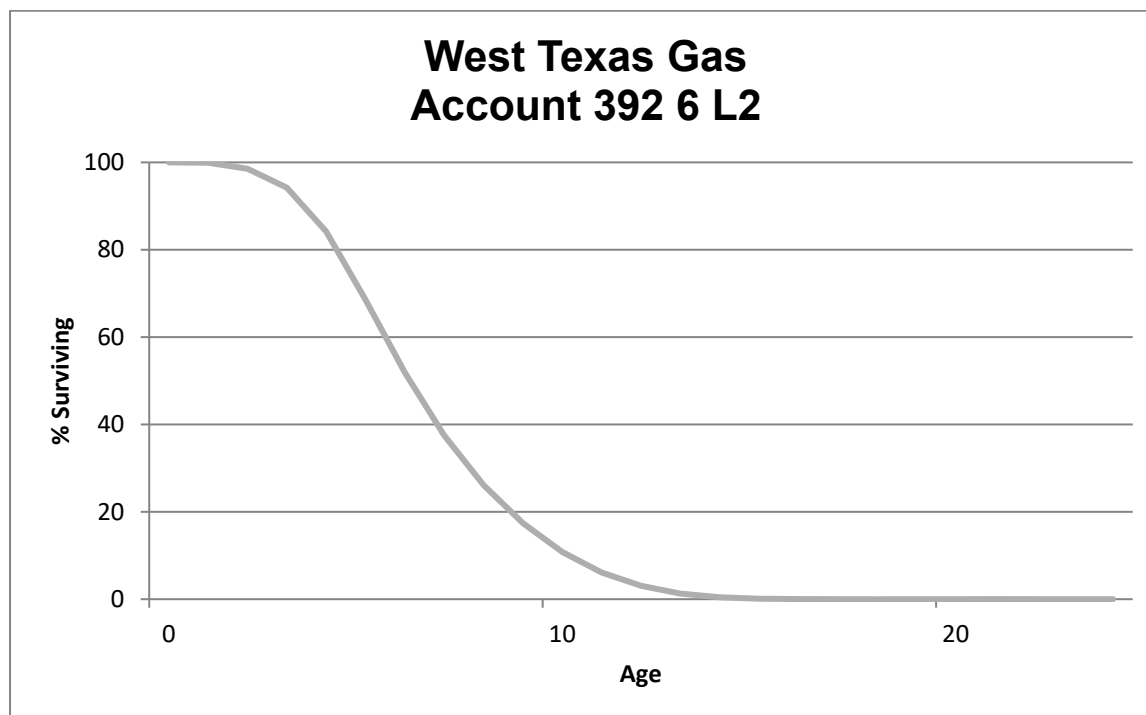
Account 390 Structures & Improvements (50 R0.5)

This account includes the cost of structures and improvements used for utility service. There is approximately \$4.6 million of current investment in this account. The current life for this account is 45 years with an R0.5 dispersion. Nearly half of the existing investment relates to the new Amarillo office built in 2019. Based on life analysis, the mix of assets in the account and judgment, this study recommends increasing to a 50-year life and R0.5 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.



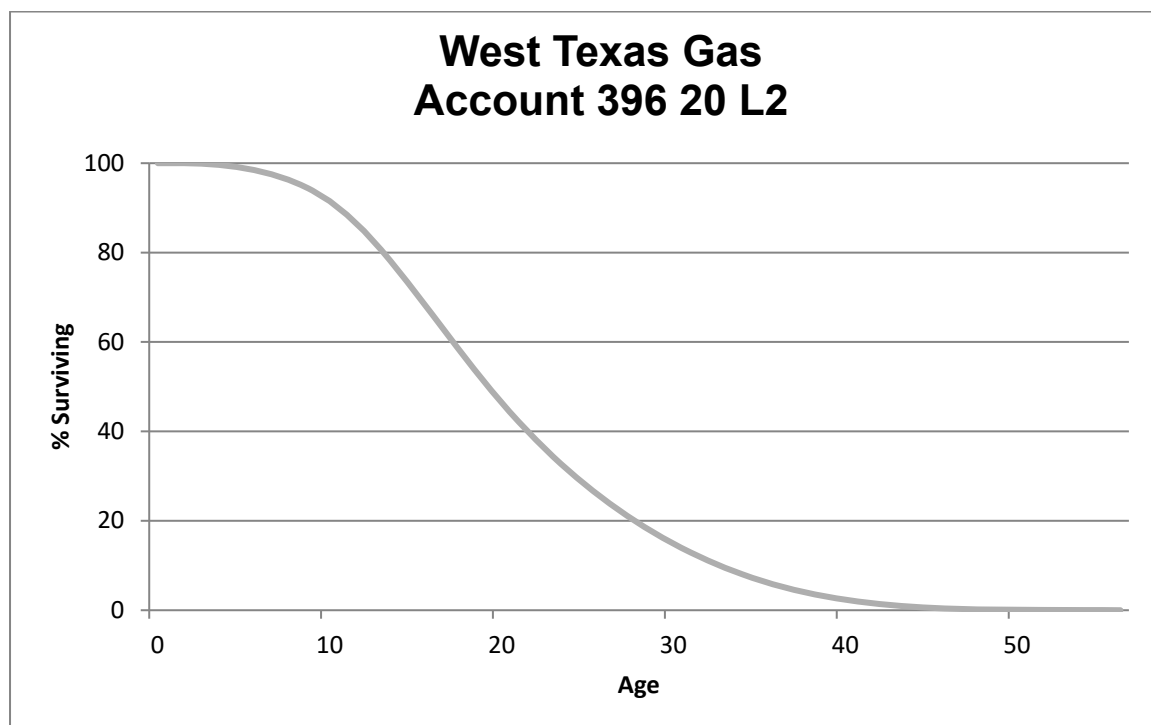
Account 392 Transportation Equipment (6 L2)

This account consists of motor cars, trucks, and other transportation equipment that can be licensed on roadways. There is approximately \$2.9 million of current investment in this account. The current life for this account is 8 years with an L2 dispersion. The majority of existing investment relates to pickup trucks. The Company currently replaces vehicles based on mileage approximately every 6 years. Operations has been experiencing a shorter life for many of the vehicles due to transmission failures and retiring vehicles earlier. While reviewing the operating lives of the various assets in this account, investment related to the longer-lived assets, such as backhoes and excavators, previously recorded in this account has been transferred to Account 396 Power Operating Equipment. Based on life analysis, the current mix of assets in this account, and judgment, this study recommends decreasing to a 6-year life and retaining the existing L2 dispersion curve for this account. A graph of the proposed dispersion curve is shown below.



Account 396 Power Operating Equipment (20 L2)

This newly created account consists of operating equipment such as excavators, backhoes, forklifts, and other power operating equipment used to support gas operations. Approximately \$356 thousand of current investment was transferred from other general plant accounts. This account was newly created to track power operating equipment, which typically has a longer operating life separately from licensed transportation equipment recorded in Account 392. Most of the existing investment relates to excavators, which have an estimated operating life of 20 years depending on usage and number of operating hours. Based on the mix of assets in this account and judgment, this study recommends using a 20-year life and an L2 dispersion curve for this account. A graph of the proposed dispersion curve is shown below.



General Plant Amortized Accounts

This study continues the use of vintage group amortization for select amortized general plant accounts, following Accounting Release 15 guidelines, which is the same methodology approved in the Company's previous depreciation study. When using this methodology, assets whose age is longer than the recommended service life for each group are retired. Those amounts are shown for each account in Appendix A. After those assets are retired, the remaining plant in service for each account will be amortized using the amortization rates shown in Appendices A and B. Annually, assets which reach the average service life of each account are retired when the assets reach their average service life.

Account 391 Office Furniture and Equipment (20 SQ)

This account consists of miscellaneous office furniture such as desks, chairs, filing cabinets, and tables. There is approximately \$266 thousand of current investment after retirement of fully accrued assets. The current life for this account is 20 years with a SQ dispersion. Actuarial analysis indicates a slightly shorter life; however, existing investment includes copiers and scanning equipment that are currently 10 years old and expected to last another 5 or 10 years. The Company recently added an imaging system in 2013 that includes software and scanners, which they expect to last at least 20 years. Based on judgment and the types of assets in the account, this study recommends retaining the existing 20-year life and a SQ dispersion curve for this account.

Account 391.1 Computer Equipment (5 SQ)

This account consists of laptops, monitors, and other related computer equipment. There is approximately \$8 thousand of current investment after retirement of fully accrued assets. The current life for this account is 5 years with a SQ dispersion. The Company typically replaces computers and related equipment using a 5-year lifecycle. Based on life analysis and judgment, this study

recommends retaining the existing 5-year life and SQ dispersion curve for this account.

Account 394 Tools, Shop, and Garage Equipment (25 SQ)

This account consists of various items or tools used in shops and garages, including meter reading equipment, leak detectors, and other related field equipment. There is approximately \$1.2 million of current investment in this account. The current life for this account is 25 years with a SQ dispersion. Existing investment includes an odorization system, air compressors, and a welder, which have at least a 20-year life. Leak detectors are also estimated to have an operational life of 20 years. The tapping machine is estimated to have a useful life of at least 30 years. Operations stated the lives and type of assets in this account are similar to the assets in Account 387 Other Equipment, which is using a 23-year life. Based on life analysis, information provided by Company personnel, and judgment, this study recommends retaining the existing 25-year life and a SQ dispersion curve for this account.

Account 397 Communication Equipment (12 SQ)

This account consists of miscellaneous communication equipment, such as microwave equipment, radio equipment, and SCADA equipment. There is approximately \$529 thousand of current investment after retirement of fully accrued assets. The current life for this account is 15 years with an SQ dispersion. The majority of investment relates to a SCADA system installed in 2017, which included capitalized software and related electronic equipment estimated to have an operational life between 10 and 12 years. The Company is currently experiencing a shorter life between 10 and 12 years for radios due to fast changing technology. Based on life analysis, the current mix of assets, and judgment, this study recommends decreasing to a 12-year life and retaining the existing SQ dispersion curve for this account.

Account 398 Miscellaneous Equipment (15 SQ)

This account consists of miscellaneous equipment such as steel storage containers, tools, ice machines, and security equipment. This account contains \$160 thousand of current investment after retirement of fully accrued assets. The steel containers are approximately 5 years old and are expected to last at least 15 years. Based on life analysis and judgment, this study recommends retaining the existing 15-year life and a SQ dispersion curve for this account.

NET SALVAGE ANALYSIS

When a capital asset is retired, physically removed from service and finally disposed of, terminal retirement is said to have occurred. The residual value of a terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset). Gross salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. Historically, WTG has booked removal costs to the cost of a new installation. Consistent with the general practice for other regulated natural gas utilities, Alliance Consulting Group recommends that the Company move to tracking gross salvage and removal. The current study assumes a zero percent net salvage in depreciation rates, with the exception of vehicles.

WTG has consistently recorded gross salvage at the time of retirement for vehicles since 2012. Alliance analyzed combined gross salvage from its Texas and Oklahoma operations for Account 392 Transportation Equipment. Historical transactional data was available from 2012 to 2023. The net salvage data is discussed below for this account. A detailed calculation of rolling net salvage percentages for Account 392 is provided in Appendix D.

Account 392 Transportation Equipment (10 Percent)

This account includes any salvage related to transportation equipment such as licensed cars and trucks. There is currently positive 10 percent net salvage for this account. No removal cost has been recorded in this account. Current analysis indicates an increasing positive net salvage percentage since 2012. The 10-year rolling net salvage percent has ranged from positive 4.30 percent to 12.08 percent. Based on net salvage analysis, consistent amounts of positive salvage being recorded, and judgement, this study recommends retaining the existing positive 10 percent net salvage for this account.

Account 396 Operating Equipment (10 Percent)

This is a new account being added since the last study. This account will include salvage related to power operating equipment. The current assets in this account were transferred from Account 392 Transportation Equipment and other general plant accounts. Typically, when retiring power operating equipment, there is minimal removal cost and salvage is recorded, similar to equipment in Account 392. Based on the net salvage experience for similar assets in Account 392 and judgement, this study recommends a positive 10 percent net salvage for this account.

APPENDIX A
Computation of Annual Accrual Rates and Amounts

WEST TEXAS GAS
Computation of Proposed Depreciation Accrual Rates and Amounts - Texas
Using Equal Life Group Depreciation
As of December 31, 2023

Account	Description	Plant Balance at 12/31/2023	Allocated Book Reserve	Net Salvage %	Net Salvage Amount	Unaccrued Balance	Average Remaining Life	Annual Accrual Amount	Annual Accrual Rate	
(a)	(b)	(c)	(d)	(e)	(f)= (e)/100*(c)	(g)=(c)-(d)-(f)	(h)	(i)=(g)/(h)	(j)=(i)/(c)	
Intangible Plant										
303	Intangible Plant	378,314.96	626,340.11	0%	-	(248,025.15)	0.00	-	0.00%	Note 1
	Total Intangible Plant	378,314.96	626,340.11		-	(248,025.15)				
Gathering Plant										
332	Field Lines	3,048,810.58	3,345,891.64	0%	-	(297,081.06)	16.62	-	0.00%	Note 1
334	Field Measuring & Regulating Equip	100,000.00	100,000.00	0%	-	-	9.82	-	0.00%	Note 1
	Total Gathering Plant	3,148,810.58	3,445,891.64		-	(297,081.06)		-		
Transmission Plant										
365.2	Land Rights	5,379,123.47	1,270,864.57	0%	-	4,108,258.90	35.36	116,171.08	2.16%	
367	Transmission Mains	45,312,826.71	13,084,107.96	0%	-	32,228,718.75	32.05	1,005,481.75	2.22%	
369	Field Measuring and Regulating Equipment	1,051,356.12	375,755.55	0%	-	675,600.57	25.87	26,114.26	2.48%	
369.1	Meters and Regulators	362,104.33	152,761.73	0%	-	209,342.60	23.77	8,805.41	2.43%	
371	Other Equipment	224,147.69	196,806.23	0%	-	27,341.46	3.18	8,585.22	3.83%	
	Total Transmission Plant	52,329,558.32	15,080,296.03		-	37,249,262.29		1,165,157.73		
Distribution Plant										
376	Distribution Mains	167,901,504.47	42,000,100.42	0%	-	125,901,404.05	32.56	3,866,867.35	2.30%	
378	Distribution Measuring and Regulating Equip	7,698,513.86	4,191,400.66	0%	-	3,507,113.20	18.89	185,707.82	2.41%	
378.1	Meters	-	-		-	-			5.00%	Note 2
387	Other Equipment	688,098.21	513,486.62	0%	-	174,611.59	8.11	21,527.86	3.13%	
	Total Distribution Plant	176,288,116.54	46,704,987.70		-	129,583,128.84		4,074,103.03		
General Plant - Depreciated										
389	General Plant Land Rights	6,308,628.50	2,473,585.09	0%	-	3,835,043.41	33.43	114,717.55	1.82%	
390	Structures and Improvements	4,562,845.55	1,045,660.50	0%	-	3,517,185.05	28.28	124,373.07	2.73%	
392	Transportation Equipment	2,912,606.36	1,828,299.18	10%	291,260.64	793,046.55	2.60	304,654.70	10.46%	
396	Power Operating Equipment	356,491.76	150,821.70	10%	35,649.18	170,020.89	11.09	15,334.24	4.30%	
		14,140,572.17	5,498,366.46		326,909.81	8,315,295.90		559,079.56		

General Plant - Amortized

Account	Description	Plant Balance at 12/31/2019	Allocated Book Reserve	Theoretical Reserve	Reserve Deficit	Remaining Life	Amortized Reserve Difference	Asset to Retire
391	Office Furniture and Equipment	326,694.56	180,893.66	162,281.90	18,611.75	10.07	1,849.12	60,673.37
391.1	Computer Equipment	96,090.77	94,450.97	93,786.19	664.78	1.51	439.34	88,475.55
394	Tools, Shop, and Garage Equipment	1,290,075.98	725,056.13	641,071.10	83,985.03	12.58	6,677.74	76,304.15
397	Communication Equipment	583,844.64	357,357.37	311,216.47	46,140.90	5.60	8,234.39	54,358.23
398	Miscellaneous Equipment	250,526.44	140,026.75	132,301.58	7,725.17	7.08	1,091.34	90,127.00
		2,547,232.39	1,497,784.88	1,340,657.25	157,127.63		18,291.92	369,938.30

After Retirement of Fully Accrued Assets

Account	Description	Plant Balance at 12/31/2019	Allocated Book Reserve	Proposed Life	Accrual Rate	Annual Amortization	Accrual for Reserve Difference
391	Office Furniture and Equipment	266,021.19	120,220.29	20.00	5.00%	13,301.06	(1,849.12)
391.1	Computer Equipment	7,615.22	5,975.42	5.00	20.00%	1,523.04	(439.34)
394	Tools, Shop, and Garage Equipment	1,213,771.83	648,751.98	25.00	4.00%	48,550.87	(6,677.74)
397	Communication Equipment	529,486.41	302,999.14	12.00	8.33%	44,123.87	(8,234.39)
398	Miscellaneous Equipment	160,399.44	49,899.75	15.00	6.67%	10,693.30	(1,091.34)
		2,177,294.09	1,127,846.58			118,192.14	(18,291.92)

Note 1 Existing investment is fully depreciated. Company should apply a Whole Life rate as follows for new investment:
 Account 303 6.67% (1/15)
 Account 332 2.22% (1/45)
 Account 334 2.78% (1/36)

Note 2 New Subaccount 378.1 Distribution Meters should apply Whole Life rate of 5.00% (1/20) for new investment in Meters

APPENDIX A-1
Computation of Remaining Life

WEST TEXAS GAS
Computation of Remaining Life - Texas
Using Equal Life Group Depreciation
As of December 31, 2023

Account	Description	Plant Balance at 12/31/2023	Theoretical Reserve 0%	Undepreciated Balance	Annual Accrual	Remaining Life
(a)	(b)	(c)	(d)= (b) - (c)	(e)	(f)=(d)/(e)	
303	Intangible Plant	378,314.96	378,314.96	-	18,137.38	0.00
332	Field Lines	3,048,810.58	1,963,423.68	1,085,386.90	65,297.99	16.62
334	Field Measuring & Regulating Equip	100,000.00	73,681.20	26,318.80	2,679.32	9.82
365.2	Land Rights	5,379,123.47	1,151,865.38	4,227,258.09	119,536.08	35.36
367	Transmission Mains	45,312,826.71	11,858,959.07	33,453,867.64	1,043,704.33	32.05
369	Measuring and Regulating Equipment	1,051,356.12	340,571.15	710,784.97	27,474.25	25.87
369.1	Meters and Regulators	362,104.33	138,457.67	223,646.66	9,407.07	23.77
371	Other Equipment	224,147.69	182,980.43	41,167.26	12,926.53	3.18
376	Distribution Mains	167,901,504.47	36,487,340.70	131,414,163.77	4,036,183.26	32.56
378	Distribution Measuring and Regulating Equipment	7,698,513.86	3,658,778.44	4,039,735.42	213,911.10	18.89
387	Other Equipment	688,098.21	463,879.92	224,218.29	27,643.87	8.11
389	General Plant Land Rights	6,308,628.50	2,090,640.07	4,217,988.43	126,172.57	33.43
390	Structures and Improvements	4,562,845.55	883,777.86	3,679,067.69	130,097.49	28.28
392	Transportation Equipment	2,912,606.36	1,718,483.18	1,194,123.18	458,731.26	2.60
396	Power Operating Equipment	356,491.76	141,636.03	214,855.73	19,377.91	11.09

APPENDIX B

Comparison of Existing versus Proposed Accrual Rates and Amounts

WEST TEXAS GAS
Comparison of Existing versus Proposed Accrual Rates and Amounts - Texas
As of December 31, 2023

Account (a)	Description (b)	Plant Balance at 12/31/2023 (c)	Existing Annual Accrual		Proposed Annual Accrual		Difference (h) = (g) - (e)
			Rate % (d)	Amount (e)=(c)*(d)	Rate % (f)	Amount (g)=(c)*(f)	
Intangible Plant							
303	Intangible Plant	378,314.96	0.00%	-	0.00%	-	-
	Total Intangible Plant	378,314.96		-		-	-
Gathering Plant							
332	Field Lines	3,048,810.58	0.00%	-	0.00%	-	-
334	Field Measuring & Regulating Equip	100,000.00	0.00%	-	0.00%	-	-
	Total Gathering Plant	3,148,810.58		-		-	-
Transmission Plant							
365.2	Land Rights	5,379,123.47	2.21%	118,878.63	2.16%	116,171.08	(2,707.55)
367	Transmission Mains	45,312,826.71	2.54%	1,150,945.80	2.22%	1,005,481.75	(145,464.05)
369	Field Measuring and Regulating Equipment	1,051,356.12	2.61%	27,440.39	2.48%	26,114.26	(1,326.14)
369.1	Meters and Regulators	362,104.33	2.54%	9,197.45	2.43%	8,805.41	(392.04)
371	Other Equipment	224,147.69	4.85%	10,871.16	3.83%	8,585.22	(2,285.94)
	Total Transmission Plant	52,329,558.32		1,317,333.43		1,165,157.73	(152,175.71)
Distribution Plant							
376	Distribution Mains	167,901,504.47	2.61%	4,382,229.27	2.30%	3,866,867.35	(515,361.92)
378	Distribution Measuring and Regulating Equip	7,698,513.86	2.61%	200,931.21	2.41%	185,707.82	(15,223.39)
378.1	Meters	-		-	5.00%	-	-
387	Other Equipment	688,098.21	3.81%	26,216.54	3.13%	21,527.86	(4,688.68)
	Total Distribution Plant	176,288,116.54		4,609,377.02		4,074,103.03	(535,273.99)
General Plant - Depreciated							
389	General Plant Land Rights	6,308,628.50	2.01%	126,803.43	1.82%	114,717.55	(12,085.89)
390	Structures and Improvements	4,562,845.55	4.24%	193,464.65	2.73%	124,373.07	(69,091.58)
392	Transportation Equipment	2,912,606.36	10.66%	310,483.84	10.46%	304,654.70	(5,829.14)
396	Power Operating Equipment	356,491.76			4.30%	15,334.24	15,334.24
		14,140,572.17		630,751.92		559,079.56	(71,672.36)

WEST TEXAS GAS
Comparison of Existing versus Proposed Accrual Rates and Amounts - Texas
As of December 31, 2023

Account (a)	Description (b)	Plant Balance at 12/31/2023 (c)	Existing Annual Accrual		Proposed Annual Accrual		Difference (h) = (g) - (e)
			Rate % (d)	Amount (e)=(c)*(d)	Rate % (f)	Amount (g)=(c)*(f)	
General Plant - Amortized							
391	Office Furniture and Equipment	266,021.19	5.00%	13,301.06	5.00%	13,301.06	-
391.1	Computer Equipment	7,615.22	20.00%	1,523.04	20.00%	1,523.04	-
394	Tools, Shop, and Garage Equipment	1,213,771.83	4.00%	48,550.87	4.00%	48,550.87	-
397	Communication Equipment	529,486.41	6.67%	35,316.74	8.33%	44,123.87	8,807.12
398	Miscellaneous Equipment	160,399.44	6.67%	10,698.64	6.67%	10,693.30	(5.35)
		2,177,294.09		109,390.36		118,192.14	8,801.78
	Amortized Reserve Difference					(18,291.92)	(18,291.92)
Grand Total		248,462,666.66		6,666,852.74		5,898,240.53	(768,612.21)

Note 1 Existing investment is fully depreciated. Company should apply a Whole Life rate as follows for new investment:
Account 303 6.67% (1/15)
Account 332 2.22% (1/45)
Account 334 2.78% (1/36)

Note 2 New Subaccount 378.1 Distribution Meters should apply Whole Life rate of 5.00% (1/20) for new investment in Meters

APPENDIX C
Comparison of Depreciation Parameters

WEST TEXAS GAS
Comparison of Existing versus Proposed Life Parameters
at December 31, 2023

Account		Existing			Proposed		
		Life	Curve	Net Salvage	Life	Curve	Net Salvage
(a)	(b)						
303	Intangible Plant	17	SQ	0%	15	SQ	0%
332	Field Lines	45	R3	0%	45	R3	0%
334	Field Measuring & Regulating Equip	36	R4	0%	36	R4	0%
365.2	Land Rights	45	SQ	0%	45	SQ	0%
367	Transmission Mains	45	R2	0%	50	R2	0%
369	Measuring and Regulating Equipment	40	R4	0%	40	R4	0%
369.1	Meters and Regulators	40	R4	0%	40	R4	0%
371	Other Equipment	20	R5	0%	15	R4	0%
376	Distribution Mains	45	R2	0%	50	R2	0%
378	Distribution Measuring and Regulating Equipment	36	R5	0%	36	R5	0%
378.1	Meters				20	R2	0%
387	Other Equipment	23	S4	0%	23	S4	0%
389	General Plant Land Rights	45	SQ	0%	50	SQ	0%
390	Structures and Improvements	45	R0.5	0%	50	R0.5	0%
391	Office Furniture and Equipment	20	SQ	0%	20	SQ	0%
391.1	Computer Equipment	5	SQ	0%	5	SQ	0%
392	Transportation Equipment	8	L2	10%	6	L2	10%
394	Tools, Shop, and Garage Equipment	25	SQ	0%	25	SQ	0%
396	Power Operating Equipment				20	L2	10%
397	Communication Equipment	15	SQ	0%	12	SQ	0%
398	Miscellaneous Equipment	15	SQ	0%	15	SQ	0%

APPENDIX D
Net Salvage Analysis

WEST TEXAS GAS
Net Salvage Analysis
At December 31, 2023

Acct	Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
Account 392 Automobiles															
392.0	2012	1,987,561	5,850	0	5,850	0.29%									
392.0	2013	49,807	3,500	0	3,500	7.03%	0.46%								
392.0	2014	124,242	12,403	0	12,403	9.98%	9.14%	1.01%							
392.0	2015	412,647	11,850	0	11,850	2.87%	4.52%	4.73%	1.31%						
392.0	2016	418,629	9,200	0	9,200	2.20%	2.53%	3.50%	3.68%	1.43%					
392.0	2017	228,257	7,100	0	7,100	3.11%	2.52%	2.66%	3.43%	3.57%	1.55%				
392.0	2018	146,109	14,500	0	14,500	9.92%	5.77%	3.88%	3.54%	4.14%	4.24%	1.91%			
392.0	2019	288,387	37,390	0	37,390	12.97%	11.94%	8.90%	6.31%	5.36%	5.71%	5.75%	2.78%		
392.0	2020	449,240	36,200	0	36,200	8.06%	9.98%	9.97%	8.56%	6.82%	5.98%	6.22%	6.24%	3.36%	
392.0	2021	486,191	59,356	0	59,356	12.21%	10.22%	10.86%	10.76%	9.67%	8.12%	7.23%	7.36%	7.36%	4.30%
392.0	2022	260,237	21,000	0	21,000	8.07%	10.77%	9.75%	10.37%	10.33%	9.45%	8.11%	7.31%	7.43%	7.42%
392.0	2023	1,148,220	269,694	0	269,694	23.49%	20.64%	18.48%	16.48%	16.09%	15.77%	14.81%	13.27%	12.15%	12.08%

Retirement and Salvage Amounts combine TX and OK

Testimony Appearances - Dane A. Watson
07/03/2024

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-24-017	Matanuska Electric Coop	2024	Electric Depreciation Study
New Mexico	Public Service of New Mexico	24-00089-UT	PNM Resources	2024	Electric Technical Update
Texas	Public Utility Commission of Texas	56665	Texas Water Utilities	2024	Water/Wastewater Depreciation Study
Multi-state	FERC	EL24-60-000	Viridon Mid-Atlantic LLC	2024	Electric Transmission Depreciation Study
Multi-state	FERC	EL24-66-000	Viridon Southwest LLC	2024	Electric Transmission Depreciation Study
Multi-state	FERC	EL24-67-000	Viridon New York Inc.	2024	Electric Transmission Depreciation Study
Multi-state	FERC	EL24-69-000	Viridon Midcontinent LLC	2024	Electric Transmission Depreciation Study
North Carolina	North Carolina Utilities Commission	G-9, Sub 837	Piedmont Natural Gas	2024	Gas Depreciation Study
Mississippi	FERC	ER-24-1652-000	Mississippi Power Company	2024	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR24020158	Elizabethtown Gas Company	2024	Gas Depreciation Study
Texas New Mexico	FERC	ER24-1431-000	Southwestern Public Service Company	2024	Electric Technical Update
Missouri	Missouri Public Service Commission	WR-2024-0104	Liberty Utilities Missouri Water	2024	Water Depreciation Study
Missouri	Missouri Public Service Commission	SR-2024-0105	Liberty Utilities Missouri Waste Water	2024	Waste Water Depreciation Study
Texas	Public Utility Commission of Texas	56211	CenterPoint	2024	Electric Depreciation Study
California	California Public Utilities Commission	A.24-01-001	San Jose Water Co	2024	Water/Wastewater Depreciation Study
Missouri	Missouri Public Service Commission	GR-2024-0106	Liberty Utilities Midstates Gas	2024	Gas Depreciation Study
Pennsylvania	Pennsylvania Public Utility Commission	R-2024-3045193	Veolia Pennsylvania	2024	WasteWater Depreciation Study
Pennsylvania	Pennsylvania Public Utility Commission	R-2024-3045192	Veolia Pennsylvania	2024	Water Depreciation Study
Arkansas	Arkansas Public Service Commission	23-079-U	Summit Utilities Arkansas	2024	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	23A-0632G	Atmos Energy	2023	Gas Clean Heat Plan
Oklahoma	Oklahoma Corporation Commission	2023-00087	Oklahoma Gas & Electric	2023	Electric Depreciation Study
Illinois	Illinois Commerce Commission	24-0043	Liberty Mid States Gas- Illinois	2023	Gas Depreciation Study

Testimony Appearances - Dane A. Watson
07/03/2024

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Michigan	Michigan Public Service Commission	U-21513	Upper Peninsula Power Company	2023	Electric Depreciation Study
Texas	Public Utility Commission of Texas	55867	Lower Colorado River Authority	2023	Electric Depreciation Study
Texas	Railroad Commission of Texas	Case No. OS-23-00015513	CenterPoint Texas Gas	2023	Gas Depreciation Study
Nevada	Public Utility Commission of Nevada	23-090-12	Southwest Gas	2023	Gas Depreciation Study - Nevada Division
Louisiana	Public Service Commission of Louisiana	36959	Entergy Louisiana	2023	Electric Depreciation Study
Texas	Railroad Commission of Texas	13758	Atmos Energy - APT	2023	Gas Depreciation Study
Florida	Florida Public Service Commission	20230023	People Gas System	2023	Gas Depreciation Study
Texas	Public Utility Commission of Texas	54565	Central States Water Resources (CSWR Texas)	2023	Water Depreciation Study
Louisiana	Louisiana Public Service Commission	U-36923	Cleco	2023	Electric Depreciation study
New York	New York State Public Service Commission	23-W-0111	Veolia New York	2023	Water Depreciation Study
Arkansas	Arkansas Public Service Commission	22-085-U	Empire District Electric Company	2023	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	TA50-733 (U-21-058)	Cook Inlet Natural Gas Storage Alaska	2023	Focused Study - Communication Equipment
Manitoba Canada	Manitoba Public Utilities Board		Manitoba Hydro Electric	2022	Electric Depreciation Study
Tennessee	Tennessee Public Utility Commission	20-00086	Piedmont Natural Gas	2022	Gas Depreciation Study - 3 State
Texas	Public Utility Commission of Texas	54634	Southwestern Public Service Company	2023	Electric Technical Update
Arkansas	Arkansas Public Service Commission	22-085-U	Liberty Empire Electric Arkansas	2023	Electric Depreciation Study
Florida	Florida Public Service Commission	20220219	People Gas System	2022	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-21329	Michigan Gas Utilities Corporation	2022	Gas Depreciation Study
Dominica	Independent Regulatory Commission		Dominica Electricity Services LTD	2022	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	22-00270-UT	Public Service of New Mexico	2022	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	22-00286-UT	Southwestern Public Service Company	2022	Electric Technical Update

Testimony Appearances - Dane A. Watson
07/03/2024

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Minnesota	Minnesota Public Utilities Commission	22-299	Northern States Power-Minnesota	2022	Electric Gas and Common Depreciation Study
California	California Public Utilities Commission	A.22-08-010	Bear Valley Electric	2022	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-21294	SEMCO Gas	2022	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	22-064-U	Liberty Pine Bluff Water	2022	Water Depreciation Study
Colorado	Colorado Public Utilities Commission	22AL-0348G	Atmos Energy	2022	Gas Depreciation Study
New York	FERC	ER22-2581-000	New York Power Authority	2022	Transmission and General Depreciation Study
South Carolina	South Carolina Public Service Commission	2022-89-G	Piedmont Natural Gas	2022	Natural Gas Depreciation Study
California	California Public Utilities Commission	A.22-007-001	California American Water	2022	Water and Waste Water Depreciation Study
Alaska	Regulatory Commission of Alaska	U-22-034	Chugach Electric Association	2022	Electric Depreciation Study
Georgia	Georgia Public Service Commission	44280	Georgia Power Company	2022	Electric Depreciation Study
California	California Public Utilities Commission	22-005-xxx	San Diego Gas and Electric	2022	Electric Gas and Common Depreciation Study
California	California Public Utilities Commission	22-005-xxx	Southern California Gas	2022	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	22AL-0046G	Public Service of Colorado	2022	Gas Depreciation given potential for climate change
Texas	Public Utility Commission of Texas	53601	Oncor Electric Delivery	2022	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR2222040253	South Jersey Gas	2022	Gas Depreciation Study
Oklahoma	Corporation Commission of Oklahoma	PUD 202100163	Empire District Electric Company	2022	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-21176	Consumers Gas	2021	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR21121254	Elizabethtown Natural Gas	2021	Gas Depreciation Study
Ontario Canada	Ontario Energy Board	EB-2021-0110	Hydro One	2021	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	TA116-118, TA115-97, TA160-37 and TA110-290	Fairbanks Water and Wastewater	2021	Water and Waste Water Depreciation Study
Colorado	Public Utilities Commission of Colorado	21AL-0317E	Public Service of Colorado	2021	Electric and Common Depreciation Study

Testimony Appearances - Dane A. Watson
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Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-21-025	Golden Valley Electric Association	2021	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	5-DU-103	WE Energies	2021	Electric and Gas Depreciation Study
Kentucky	Public Service Commission of Kentucky	2021-00214	Atmos Kentucky	2021	Gas Depreciation Study
Missouri	Missouri Public Service Commission	ER-2021-0312	Empire District Electric Company	2021	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-111	Northern States Power Wisconsin	2021	Transmission, Distribution General and Common Depreciation Study
Louisiana	Louisiana Public Service Commission	U-35951	Atmos Energy	2021	Statewide Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015-D-21-229	Allete Minnesota Power	2021	Intangible, Transmission, Distribution, and General Depreciation Study
Michigan	Michigan Public Service Commission	U-20849	Consumers Energy	2021	Electric and Common Depreciation Study
Texas	Texas Public Utility Commission	51802	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	RP21-441-000	Florida Gas Transmission	2021	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	20-00238-UT	Southwestern Public Service Company	2021	Electric Technical Update
Yukon Territory Canada	Yukon Energy Board	2021 General Rate Application	Yukon Energy	2020	Electric Depreciation Study
MultiState	FERC	ER21-709-000	American Transmission Company	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51611	Sharyland Utilities	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51536	Brownsville Public Utilities Board	2020	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	WR20110729	Suez Water New Jersey	2020	Water and Waste Water Depreciation Study
Idaho	Idaho Public Service Commission	SUZ-W-20-02	Suez Water Idaho	2020	Water Depreciation Study

Testimony Appearances - Dane A. Watson
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Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Texas Public Utility Commission	50944	Monarch Utilities	2020	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-20844	Consumers Energy/DTE Electric	2020	Ludington Pumped Storage Depreciation Study
Mexico	Comision Reguladora de Energia	G/352/TRA/2015 UH-250/125738/2019	Arguelles Depreciation Study	2020	Gas Depreciation Study
Tennessee	Tennessee Public Utility Commission	2000086	Piedmont Natural Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	OS-00005136	CoServ Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10988	EPCOR Gas Texas	2020	Gas Depreciation Study
Florida	Florida Public Service Commission	20200166-GU	People Gas System	2020	Gas Depreciation Study
Mississippi	Federal Energy Regulatory Commission	ER20-1660-000	Mississippi Power Company	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50557	Corix Utilities	2020	Water and Waste Water Depreciation Study
Georgia	Georgia Public Service Commission	42959	Liberty Utilities Peach State Natural Gas	2020	Gas Depreciation Study
Texas	Public Utility Commission of Texas	50734	Oncor Electric Delivery	2020	Life of Intangible Plant
New Jersey	New Jersey Board of Public Utilities	GR20030243	South Jersey Gas	2020	Gas Depreciation Study
Kentucky	Kentucky Public Service Commission	2020-00064	Big Rivers	2020	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	20AL-0049G	Public Service of Colorado	2020	Gas Depreciation Study
New York	Federal Energy Regulatory Commission	ER20-716-000	LS Power Grid New York, Corp.	2019	Electric Transmission Depreciation Study
Mississippi	Mississippi Public Service Commission	2019-UN-219	Mississippi Power Company	2019	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50288	Kerrville Public Utility District	2019	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10920	CenterPoint Gas	2019	Gas Depreciation Study and Propane Air Study
Texas, New Mexico	Federal Energy Regulatory Commission	ER20-277-000	Southwestern Public Service Company	2019	Electric Production and General Plant Depreciation Study
New Mexico	New Mexico Public Regulation Commission		New Mexico Gas	2019	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-19-086	Alaska Electric Light and Power	2019	Electric Depreciation Study

Testimony Appearances - Dane A. Watson
07/03/2024

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Railroad Commission of Texas	GUD 10900	Atmos Energy West Texas Division - Triangle	2019	Depreciation Rates for Natural Gas Property
Delaware	Delaware Public Service Commission	19-0615	Suez Water Delaware	2019	Water Depreciation Study
California	California Public Utilities Commission	A.19-08-015	Southwest Gas Northern California	2019	Gas Depreciation Study
California	California Public Utilities Commission	A.19-08-015	Southwest Gas Southern California	2019	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10895	CenterPoint Propane Air	2019	Depreciation Rates for Propane Air Assets
Texas	Public Utility Commission of Texas	49831	Southwestern Public Service Company	2019	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	19-00170-UT	Southwestern Public Service Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42516	Georgia Power Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42315	Atlanta Gas Light	2019	Gas Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-19-0055	Southwest Gas Corporation	2019	Gas Removal Cost Study
New Hampshire	New Hampshire Public Service Commission	DE 19-064	Liberty Utilities	2019	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR19040486	Elizabethtown Natural Gas	2019	Gas Depreciation Study
Texas	Public Utility Commission of Texas	49421	CenterPoint Houston Electric LLC	2019	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket No. G-9, Sub 743	Piedmont Natural Gas	2019	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E-015/D-18-226	Allete Minnesota Power	2018	Electric Compliance Filing
Colorado	Colorado Public Utilities Commission	19AL-0063ST	Public Service of Colorado	2019	Steam Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study

Testimony Appearances - Dane A. Watson
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Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48500	Golden Spread Electric Coop	2018	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-34803	Atmos LGS	2018	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E-015/D-18-226	Allete Minnesota Power	2018	Electric Depreciation Rate
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study
Texas	City of Dallas Statement of Intent	NA	Atmos Mid-Tex	2017-2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
New Mexico	FERC	ER18-228-000	Southwestern Public Service Company	2017	Electric Production Depreciation Study
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	17-00255-UT	Southwestern Public Service Company	2017	Electric Production Depreciation Study
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilities	2017	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	47527	Southwestern Public Service Company	2017	Electric Production Depreciation Study
Minnesota	Minnesota Public Utilities Commission	17-581	Minnesota Northern States Power	2017	Electric, Gas and Common Transmission, Distribution and General
Colorado	Colorado Public Utilities Commission	17AL-0363G	Public Service of Colorado-Gas	2017	Gas Depreciation Study
MultiState	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Louisiana	Louisiana Public Service Commission	U-34343	Atmos Trans Louisiana	2017	Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study

Testimony Appearances - Dane A. Watson
07/03/2024

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study
California	California Public Utilities Commission	A 16-07-002	California American Water	2016	Water and Waste Water Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Gas	2016	Gas Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
Georgia	N/A	N/A	Dalton Utilities	2016	Electric, Gas, Water, Wastewater & Fiber Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
MultiState	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study
New York	NA		New York Power Authority	2016	Electric Transmission and General Study
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Texas, New Mexico	FERC	ER15-949-000	Southwestern Public Service Company	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Alabama	State of Alabama Public Service Commission	U-5115	Mobile Gas	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service Company of Colorado	2014	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-28814	Atmos Energy Corporation	2014	Gas Depreciation Study

Testimony Appearances - Dane A. Watson
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Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Southwestern Public Service Company	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Virginia	Virginia Corporation Commission	PUE-2013-00124	Atmos Energy Corporation	2013-2014	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study

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Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	2012	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
North Dakota	North Dakota Public Service Commission	PU-12-0813	Northern States Power	2012	Electric, Gas and Common Transmission, Distribution and General
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study

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Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service Company of Colorado	2011	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
MultiState			Atmos Energy	2011	Shared Services Depreciation Study
Pennsylvania	NA	NA	Safe Harbor	2011	Hydro Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Texas Commission on Environmental Quality	Matter 37050-R	Southwest Water Company	2011	WasteWater Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Multistate	NA	NA	Constellation Energy Nuclear	2010	Nuclear Generation Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study

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Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service Company	2010	Electric Technical Update
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
California	California Public Utility Commission	A10071007	California American Water	2009-2010	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Wyoming	Wyoming Public Service Commission	30022-148-GR10	Source Gas	2009-2010	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service of Colorado	2009	Electric Depreciation Study
Iowa	NA		Cedar Falls Utility	2009	Telecommunications, Water, and Cable Utility
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Michigan	Michigan Public Service Commission	In Progress	Edison Sault	2009	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
New York	New York Public Service Commission		Key Span	2009	Generation Depreciation Study
North Carolina	North Carolina Utilities Commission		Piedmont Natural Gas	2009	Gas Depreciation Study
Tennessee	Tennessee Regulatory Authority	09-000183	AGL – Chattanooga Gas	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study
Multiple States	NA	NA	Constellation Energy	2008	Generation Depreciation Study
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation

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Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Colorado	Colorado Public Utilities Commission	Filed – no docket to date	Public Service Company of Colorado	2007-2008	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	10AL-963G	Public Service Company of Colorado	2007-2008	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Multiple States	NA	NA	Constellation Energy	2007	Generation Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Multiple States	Multiple	NA	CenterPoint Energy	2006	Shared Services Depreciation Study

WORKPAPERS
TO
DIRECT TESTIMONY
OF
DANE A. WATSON

Workpapers to the Direct Testimony of Dane A. Watson are voluminous and are being provided in electronic format.

CASE NO. 00017816

**STATEMENT OF INTENT OF
WEST TEXAS GAS UTILITY, LLC TO
INCREASE GAS UTILITY RATES
WITHIN THE UNINCORPORATED
AREAS OF TEXAS**

§
§
§
§
§

**BEFORE THE
RAILROAD COMMISSION
OF TEXAS**

DIRECT TESTIMONY

OF

BRUCE H. FAIRCHILD

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

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LIST OF EXHIBITS

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Exhibit BHF-11	Comparable Earnings Method

1 **DIRECT TESTIMONY OF BRUCE H. FAIRCHILD**

2 **I. INTRODUCTION**

3 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

4 A. Bruce H. Fairchild, 3907 Red River, Austin, Texas 78751.

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

6 A. I am a principal in Financial Concepts and Applications, Inc. (“FINCAP”), a firm
7 engaged in financial, economic, and policy consulting to business and government.

8 **A. Qualifications**

9 **Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL**
10 **QUALIFICATIONS, AND PRIOR EXPERIENCE.**

11 A. I hold a BBA degree from Southern Methodist University and MBA and PhD
12 degrees from the University of Texas at Austin. I am also a Certified Public
13 Accountant. My previous employment includes working in the Controller’s
14 Department at Sears, Roebuck and Company and serving as Assistant Director of
15 Economic Research at the Public Utility Commission of Texas (“PUCT”). I have
16 also been on the business school faculties at the University of Colorado at Boulder
17 and the University of Texas at Austin, where I taught undergraduate and graduate
18 courses in finance and accounting.

19 **Q. BRIEFLY DESCRIBE YOUR EXPERIENCE IN UTILITY-RELATED**
20 **MATTERS.**

21 A. While at the PUCT, I assisted in managing a division comprised of approximately
22 twenty-five professionals responsible for financial analysis, cost allocation and rate
23 design, economic and financial research, and data processing systems. I testified
24 on behalf of the PUCT staff in numerous cases involving most major investor-

1 owned and cooperative electric, telephone, and water/sewer utilities in the state
2 regarding a variety of financial, accounting, and economic issues. Since forming
3 FINCAP in 1979, I have participated in a wide range of analytical assignments
4 involving utility-related matters on behalf of utilities, industrial consumers,
5 municipalities, and regulatory commissions. I have also prepared and presented
6 expert testimony before a number of regulatory authorities addressing revenue
7 requirements, cost allocation, and rate design issues for gas, electric, telephone, and
8 water/sewer utilities. I have been a frequent speaker at regulatory conferences and
9 seminars and have published research concerning various regulatory issues. A
10 resumé that contains the details of my experience and qualifications is attached as
11 Appendix A, with Appendix B listing my prior testimony before regulatory
12 agencies since leaving the PUCT.

13 **B. Overview**

14 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

15 A. The purpose of my testimony is three-fold. First, I sponsor the revenue
16 requirements, or total cost of providing service, for West Texas Gas Utility, LLC's
17 ("WTGU") natural gas distribution operations in Texas. Second, I perform the
18 class cost-of-service study ("COSS") that allocates WTGU's total Texas revenue
19 requirements between its Jurisdictional Domestic and Non-Domestic customers
20 and its Non-Jurisdictional customers. Third, I develop a fair rate of return to apply
21 to WTGU's invested capital, or rate base, to be used to determine its cost of
22 providing service in this case and for subsequent interim rate adjustments.

1 **Q. WHAT GUIDED YOUR DEVELOPMENT OF WTGU'S REVENUE**
2 **REQUIREMENTS AND COSS?**

3 A. The Rate Filing Schedules in this filing are generally patterned after those in GUD
4 No. 10235 and Docket No. OS-20-00004347, which are the last two rate cases filed
5 by West Texas Gas, Inc., WTGU's predecessor. Those filings followed closely the
6 *Gas Services Division's Suggested "Best Practices" for Preparing a Statement of*
7 *Intent Proposing a Rate Increase Considered a 'Major Change.'* As in Docket No.
8 OS-20-00004347, I streamlined the Rate Filing Schedules by combining and
9 simplifying a number of schedules and omitting others that are not applicable, and
10 I believe they contain virtually all of the same information.

11 **Q. WHAT SCHEDULES AND EXHIBITS ARE YOU SPONSORING?**

12 A I am sponsoring or co-sponsoring all of the schedules in the Rate Filing Schedules
13 except those related to the Gas Reliability Infrastructure Program ("GRIP"),
14 payroll, certain expense information, and affiliates. These are identified in the
15 Table of Contents to the Rate Filing Schedules. I am also sponsoring Exhibits BHF-
16 1 through BHF-11 attached to this testimony, which are related to rate of return.

17 **C. Summary**

18 **Q. WOULD YOU BRIEFLY SUMMARIZE THE RESULTS OF YOUR**
19 **REVENUE REQUIREMENTS AND COSS ANALYSES?**

20 A. As shown on Schedule A, WTGU's Texas revenue requirements, excluding gas
21 costs, total \$34,616,294. This amount is based on a test year ended December 31,
22 2023, with Schedule A-3 summarizing the adjustments made to test year amounts.
23 Based on a COSS allocating Texas revenue requirements between customer
24 classes, I determined that \$20,367,710 and \$6,098,421 are attributable to WTGU's

1 Jurisdictional Domestic and Non-Domestic customers, respectively, with the
2 remainder being attributable to its Non-Jurisdictional customers. As shown at the
3 bottom of Schedule A, these Jurisdictional class revenue requirements represent an
4 increase over current revenues, which include WTGU’s requested GRIP charge
5 pending before the Railroad Commission of Texas (“Commission”), of
6 \$10,183,324, or 100.0%, for Domestic customers, and \$3,005,446, or 102.9%, for
7 Non-Domestic customers.

8 **Q. WHAT COST-BASED RATES RESULT FROM THESE TWO**
9 **JURISDICTIONAL CLASS REVENUE REQUIREMENTS?**

10 A. Monthly customer charges and Mcf consumption charges for Jurisdictional
11 Domestic and Non-Domestic customers based on their respective class revenue
12 requirements of \$20,367,710 and \$6,098,421 are developed on Schedule A-1. As
13 shown there, cost-based rates for Domestic customers are a \$71.63 per month
14 customer charge and \$4.67 per Mcf, and, for Non-Domestic customers, an \$82.89
15 per month customer charge and \$9.61 per Mcf.

16 **Q. HOW DO THESE COST-BASED RATES FOR WTGU’S**
17 **JURISDICTIONAL CUSTOMERS COMPARE TO CURRENT RATES?**

18 A. Schedule A-2 and the following table compare WTGU’s current rates, which
19 include WTGU’s pending requested GRIP charge, for Domestic and Non-Domestic
20 customers with cost-based rates:

<u>Description</u>	Current Rates	Cost-Based Rates	Percentage Change
<u>Domestic Customers</u>			
Customer Charge	\$ 23.42	\$ 71.63	205.8%
Commodity Charge (Mcf)	\$ 4.84	\$ 4.67	-3.6%
<u>Non-Domestic Customers</u>			
Customer Charge	\$ 43.57	\$ 82.89	90.2%
Commodity Charge (Mcf)	\$ 2.69	\$ 9.61	257.4%

1 **Q. IS WTGU REQUESTING THAT THE COMMISSION APPROVE THESE**
 2 **COST-BASED RATES?**

3 A. No. Because of the overall magnitude of the increases required to charge cost-
 4 based rates and the distortions to the structure of existing rates, WTGU is requesting
 5 that the Commission approve rates for Domestic customers consisting of a \$29.50
 6 monthly customer charge and a \$7.68 per Mcf consumption charge, and, for Non-
 7 Domestic customers, a monthly customer charge of \$79.00 and a consumption
 8 charge of \$4.89 per Mcf. These requested rates are compared to existing rates in
 9 the following table and on Schedule A-2:

<u>Description</u>	Current Rates	Requested Rates	Percentage Change
<u>Domestic Customers</u>			
Customer Charge	\$ 23.42	\$ 29.50	26.0%
Commodity Charge (Mcf)	\$ 4.84	\$ 7.68	58.7%
<u>Non-Domestic Customers</u>			
Customer Charge	\$ 43.57	\$ 79.00	81.3%
Commodity Charge (Mcf)	\$ 2.69	\$ 4.89	81.8%

10 As shown at the bottom of Schedule A, WTGU’s requested rates represent an
 11 increase in revenues from Domestic customers of \$4,327,298, or 42.5%, and from
 12 Non-Domestic customers of \$2,451,592, or 81.6%.

1 **II. REVENUE REQUIREMENTS**

2 **Q. HOW DID YOU DETERMINE WTGU’S TEXAS REVENUE**
3 **REQUIREMENTS?**

4 A. The cost of providing service on the WTGU system was based on the conventional
5 revenue requirements formula of:

6 Revenue Requirements = Operation & Maintenance Expenses +
7 Administrative & General Expenses +
8 Taxes Other than Income +
9 Depreciation Expense + Return (Rate
10 of Return X Rate Base) + Income Tax
11 Expense – Other Income

12 The test year used as the basis for measuring the components of the revenue
13 requirements formula was the twelve months ended December 31, 2023. I obtained
14 the financial and operating data used to develop WTGU’s revenue requirements
15 from WTGU’s books and records sponsored by WTGU witness Amanda Edgmon.
16 As will be explained in more detail subsequently, I made a number of adjustments
17 to WTGU’s actual expenses, investment, and operating data during the test year to
18 conform to accepted ratemaking practices and the policies of the Commission and
19 to remove amounts related to Oklahoma operations.

20 **A. Operation and Maintenance Expenses**

21 **Q. WHAT OPERATIONS AND MAINTENANCE (“O&M”) EXPENSES DID**
22 **WTGU INCUR DURING THE TEST YEAR?**

23 A. As shown on Schedule B-1 by Federal Energy Regulatory Commission (“FERC”)
24 account, WTGU incurred O&M expenses excluding gas costs, which are accounted
25 for separately through WTGU’s Gas Cost Adjustment (“GCA”), during 2023

1 totaling \$12,201,412. These O&M expenses are broken out by month on Schedule
2 B.

3 **Q. WERE ANY ADJUSTMENTS MADE TO TEST YEAR O&M EXPENSES?**

4 A. Yes. Account 858, Transmission and Compression of Gas by Others, is included
5 in the cost of gas in WTGU's GCA for Texas customers. Therefore, the \$347,264
6 in Account 858 was removed to avoid double counting this expense. Additionally,
7 \$26,370 in donations and contributions included in Account 880, Other Expenses,
8 was also removed pursuant to the Commission's rules.

9 **Q. WERE ANY OTHER ADJUSTMENTS MADE TO TEST YEAR O&M**
10 **EXPENSES?**

11 A. Yes. Because WTGU serves customers in both Texas and Oklahoma, it is
12 necessary to remove amounts attributable to Oklahoma operations to calculate the
13 cost of providing service in Texas. Accordingly, a share of the total O&M expenses
14 in WTGU's Regions 40 and 70, the two regions that operate in both states, was
15 allocated to Oklahoma in proportion to the number of customers served in the state
16 relative to the total number of customers in each region. The details of this
17 allocation are shown on Schedule B-4. The amounts in each FERC account, which
18 total \$1,131,411, were then deducted from WTGU's total O&M expenses in the
19 column labeled "Oklahoma" on Schedule B-1, with the remaining O&M expenses
20 being attributable to Texas operations.

1 **Q. DID YOU MAKE ANY ADJUSTMENTS TO O&M EXPENSES FOR**
2 **CHANGES IN PAYROLL COSTS?**

3 A. No. Per discussions with WTGU management, there were no material changes in
4 WTGU's personnel or their salaries during or subsequent to the test year that
5 warranted making adjustments to the test year payroll costs included in O&M
6 expenses.

7 **Q. AFTER MAKING THE ADJUSTMENTS DESCRIBED ABOVE, WHAT**
8 **O&M EXPENSES ARE INCLUDED IN WTGU'S TEXAS REVENUE**
9 **REQUIREMENTS?**

10 A. The adjusted O&M expenses of \$10,696,368 shown at the bottom of Schedule B-1
11 are included in Texas revenue requirements on Schedule A.

12 **B. Administrative and General Expenses**

13 **Q. WHAT ADMINISTRATIVE AND GENERAL ("A&G") EXPENSES WERE**
14 **INCURRED BY WTGU DURING THE TEST YEAR?**

15 A. As shown on Schedule B-2 by FERC account, WTGU recorded A&G expenses
16 during 2023 totaling \$6,433,393. These A&G expenses are also broken out by
17 month on Schedule B.

18 **Q. WHAT WAS THE FIRST ADJUSTMENT YOU MADE TO TEST YEAR**
19 **A&G EXPENSES?**

20 A. WTGU records interest on customer deposits in a below-the-line account, but, as
21 will be discussed later, customer deposits are deducted from rate base. So that both
22 of these related items are accounted for in revenue requirements, the \$30,504 in
23 interest expense on customer deposits during the test year was reclassified and
24 included in Account 910, Miscellaneous Customer Service Expenses.

1 **Q. WHAT OTHER ADJUSTMENTS WERE MADE TO TEST YEAR A&G**
2 **EXPENSES?**

3 A. Pursuant to the Commission's rules, amounts paid during 2023 for penalties and
4 fines (Schedule H-7), lobbying expenses (Schedule H-6), and donations and
5 contributions (Schedule H-5) were removed from Account 921, Office Supplies
6 and Expenses, Account 923, Outside Services Employed, and Account 930,
7 Miscellaneous General Expenses, respectively. Also, all entertainment, meals,
8 lodging, and travel expenses were removed from Accounts 921 and 930. These
9 adjustments total \$274,847.

10 **Q. WERE THERE ANY OTHER ADJUSTMENTS MADE TO TEST YEAR**
11 **A&G EXPENSES?**

12 A. Yes. As with O&M expenses, a portion of WTGU's A&G expenses are properly
13 allocated to Oklahoma operations. This allocation is also developed in Schedule B-
14 4. A&G expenses incurred in Regions 40 and 70 were again allocated to Oklahoma
15 in proportion to the number of customers served in the state to the total in each
16 region, while corporate A&G expenses were allocated to Oklahoma using a four-
17 factor allocator that weighted equally the number of customers, gross plant, O&M
18 expenses, and revenues in the state relative to the WTGU totals. The \$612,508 of
19 A&G expenses determined on Schedule B-4 as being attributable to Oklahoma
20 operations was deducted from adjusted A&G expenses in the column labeled
21 "Oklahoma" on Schedule B-2, with the remaining A&G expenses being
22 attributable to Texas operations.

1 **Q. AFTER MAKING THE ADJUSTMENTS DESCRIBED ABOVE, WHAT**
2 **A&G EXPENSES ARE INCLUDED IN WTGU'S TEXAS REVENUE**
3 **REQUIREMENTS?**

4 A. The adjusted A&G expenses of \$5,576,542 shown at the bottom of Schedule B-2
5 are included in Texas revenue requirements on Schedule A.

6 **C. Taxes Other than Income**

7 **Q. WHAT TAXES OTHER THAN INCOME WERE INCURRED BY WTGU**
8 **DURING THE TEST YEAR?**

9 A. Shown by month on Schedule B and in total on Schedule B-3, WTGU recorded
10 taxes other than income, which consist of payroll taxes, property taxes, and state
11 taxes during 2023 totaling \$3,218,888.

12 **Q. WERE ANY ADJUSTMENTS MADE TO THIS TEST YEAR TOTAL?**

13 A. Yes. Except for the Texas Franchise Tax, which was assigned directly to Texas
14 operations, a share of payroll, property, and remaining state taxes was allocated to
15 Oklahoma operations using the four-factor allocator described earlier. As
16 developed on Schedule B-4, this resulted in \$426,667 in taxes other than income
17 being attributable to Oklahoma, which were removed from the adjusted total.

18 **Q. AFTER MAKING THE ADJUSTMENTS DESCRIBED ABOVE, WHAT**
19 **TAXES OTHER THAN INCOME ARE INCLUDED IN WTGU'S TEXAS**
20 **REVENUE REQUIREMENTS?**

21 A. The adjusted taxes other than income of \$2,792,222 shown at the bottom of
22 Schedule B-3 are included in Texas revenue requirements on Schedule A.

1 **D. Rate Base**

2 **Q. BRIEFLY DESCRIBE THE CALCULATION OF RATE BASE FOR WTGU.**

3 A. Rate base is the amount on which a utility is entitled to earn a fair rate of return.
4 The rate base for WTGU, which is developed on Schedule C, consists of its net
5 investment in assets used to serve Texas customers less adjustments for non-
6 investor supplied capital. WTGU's net plant investment is calculated by
7 subtracting accumulated depreciation from the original cost of used and useful plant
8 in service at test year-end. Also included in rate base is WTGU's inventory in
9 materials and supplies. Meanwhile, customer deposits, contributions in aid of
10 construction ("CIACs"), and accumulated deferred income taxes ("ADIT"), which
11 are all regarded as sources of non-investor supplied capital, serve to reduce
12 WTGU's rate base.

13 **Q. WHAT WAS WTGU'S PLANT IN SERVICE AT DECEMBER 31, 2023?**

14 A. The total amount of plant in service recorded on WTGU's books at test year-end
15 by FERC account is shown in the first numerical column on Schedule C-1 and totals
16 \$291,649,056.

17 **Q. WERE ANY ADJUSTMENTS MADE TO THIS TEST YEAR-END PLANT**
18 **IN SERVICE?**

19 A. Yes. The first adjustment was to remove plant used to serve Oklahoma customers.
20 Plant located in Oklahoma was identified from WTGU's plant accounting records
21 and deducted in the column on Schedule C-1 labeled "Oklahoma-Direct." Also, a
22 portion of WTGU's corporate plant was allocated to Oklahoma operations based
23 on the proportion of Oklahoma plant to total plant, with the details being contained
24 in footnote (b). Deducting the approximately \$19.2 million in direct and allocated

1 plant attributable to Oklahoma operations from the total resulted in approximately
2 \$272.5 million being related to Texas service.

3 **Q. WERE ANY ADJUSTMENTS MADE TO TEXAS PLANT IN SERVICE?**

4 A. Yes. Several acquisition adjustments, which reflect amounts paid above the
5 original cost of plant, related to assets previously acquired by WTGU are recorded
6 on its books. Although Section 104.053 of the Texas Utilities Code allows for a
7 utility to earn a return on the adjusted value of invested capital, only the net original
8 cost of property, plant, and equipment at the time it was dedicated to public use is
9 considered in the present case. Accordingly, the acquisition adjustments recorded
10 on WTGU's books were removed.

11 **Q. WHAT OTHER ADJUSTMENTS WERE MADE TO TEXAS PLANT IN**
12 **SERVICE?**

13 A. Identified in the "Reference" column as (c), (d), (e) and (f), several adjustments
14 were made to remove some relatively minor non-utility assets from WTGU's books
15 and to implement recommendations by WTGU witness Dane Watson noted in his
16 depreciation study. These consisted of reclassifying assets from Account No. 366
17 (Transmission Structures and Improvements) to Account No. 369 (Transmission
18 Measuring & Regulating Equipment), and reclassifying certain assets in Account
19 Nos. 392 (Transportation Equipment) and 394 (Tools, Shop & Garage) to a new
20 account on WTGU's books, Account No. 396 (Power Operated Equipment).
21 Additionally, adjustments were made to remove various general plant assets that
22 had been retired but were still carried on WTGU's books at test year-end.

1 **Q. ONCE THE ADJUSTMENTS DESCRIBED ABOVE WERE MADE, WHAT**
2 **IS WTGU'S ADJUSTED TEXAS PLANT IN SERVICE AT TEST YEAR-**
3 **END?**

4 A. As shown in the last column of Schedule C-1, after removing plant related to
5 Oklahoma operations, acquisition adjustments, non-utility plant, and implementing
6 Mr. Watson's recommendations, WTGU's adjusted Texas plant in service at
7 December 31, 2023 totals \$249,166,612, which is included in Texas rate base on
8 Schedule C.

9 **Q. WERE ANY POST-TEST YEAR ADJUSTMENTS MADE TO PLANT IN**
10 **SERVICE?**

11 A. No.

12 **Q. WHAT ACCUMULATED DEPRECIATION IS RELATED TO WTGU'S**
13 **TEXAS PLANT IN SERVICE?**

14 A. Schedule C-2 develops the accumulated depreciation associated with the
15 approximately \$249.2 million of Texas plant in service developed on Schedule C-1.
16 Beginning with WTGU's depreciation reserve at December 31, 2023, of
17 \$87,190,168, corresponding adjustments were made to remove accumulated
18 depreciation and amortization associated with assets related to Oklahoma
19 operations, acquisition adjustments, and non-utility plant, and to include Mr.
20 Watson's recommended adjustments. This resulted in the adjusted Texas
21 accumulated depreciation balance shown on Schedule C-2 of \$72,990,047, which
22 is then included in Texas rate base on Schedule C.

1 **Q. WHAT NET PLANT IS INCLUDED IN WTGU'S TEXAS RATE BASE?**

2 A. As shown on Schedule C, deducting adjusted accumulated depreciation of
3 \$72,990,047 from adjusted plant in service of \$249,166,612 produces Texas net
4 plant in service of \$176,176,565.

5 **Q. WAS ANY CONSTRUCTION WORK IN PROGRESS ("CWIP")**
6 **INCLUDED IN WTGU'S TEXAS RATE BASE?**

7 A. No. Although WTGU had approximately \$5.4 million invested in CWIP at test
8 year-end, this plant under construction is not included in Texas rate base.

9 **Q. WAS A CASH WORKING CAPITAL ALLOWANCE INCLUDED IN**
10 **WTGU'S TEXAS RATE BASE?**

11 A. No. As in its last two rate cases, GUD No. 10235 and Docket No. OS-20-
12 00004347, WTGU is not requesting a cash working capital allowance be included
13 in Texas rate base.

14 **Q. WERE ANY OTHER WORKING CAPITAL ITEMS INCLUDED IN**
15 **WTGU'S TEXAS RATE BASE?**

16 A. Yes. WTGU prepays certain expenses and maintains inventories of materials and
17 supplies used in connection with the operation and maintenance of its system. As
18 shown in Schedule C-3, WTGU's prepayments and materials and supplies
19 inventories at test year-end were \$1,016,495 and \$1,963,405, respectively. Two
20 adjustments were made to these balances. The first was to remove a portion of
21 prepayments and inventories attributable to Oklahoma operations based on
22 Oklahoma plant as a percent of total WTGU plant. The second was to adjust the
23 test year-end materials and supplies balance to an average balance over the test

1 year, as is customary ratemaking practice. After making these two adjustments,
2 average prepayments of \$1,181,498 and materials and supplies inventory of
3 \$1,851,614 shown on Schedule C-3 are included in Texas rate base on Schedule C.

4 **Q. PLEASE DESCRIBE THE CUSTOMER DEPOSITS AND CIACS SHOWN**
5 **ON SCHEDULE C.**

6 A. At December 31, 2023, WTGU had \$1,508,997 in customer deposits and
7 \$23,804,581 in net CIACs recorded as credits on its books. As noted earlier,
8 customer deposits and CIACs are regarded as sources of non-investor supplied
9 capital and serve to reduce rate base.

10 **Q. DID YOU MAKE ANY ADJUSTMENTS TO THESE TEST YEAR-END**
11 **AMOUNTS?**

12 A. Yes. Some of the customer deposits and CIACs were provided by customers in
13 Oklahoma. These amounts were removed from the test year-end totals on Schedule
14 C, resulting in \$1,200,560 in customer deposits and \$23,143,350 in net CIACs
15 being deducted from Texas rate base.

16 **Q. WHAT ADIT ARE ASSOCIATED WITH WTGU'S ADJUSTED TEST**
17 **YEAR-END PLANT IN SERVICE?**

18 A. As a limited liability company, WTGU does not record income tax-related items
19 on its books. However, consistent with Section 104.055(c) of the Texas Utilities
20 Code, a federal income tax allowance is included in WTGU's revenue
21 requirements. Correspondingly, ADIT for WTGU should be calculated and
22 reflected for ratemaking purposes.

1 **Q. DID YOU CALCULATE ADIT FOR WTGU AT DECEMBER 31, 2023?**

2 A. Yes. ADIT for utilities is primarily attributable to the tax benefits arising from the
3 use of accelerated depreciation methods for tax purposes (including “bonus”
4 depreciation allowed on construction beginning in 2008) versus the straight-line
5 depreciation used for ratemaking purposes. In footnote (e) of Schedule C, total
6 ADIT at December 31, 2023 was calculated by multiplying the difference between
7 WTGU’s net plant in service and its net tax basis of plant in service times the
8 current corporate federal income tax rate of 21%. The resulting total ADIT liability
9 was then multiplied by the ratio of adjusted Texas plant in service to total plant in
10 service to remove ADIT associated with Oklahoma plant, acquisitions adjustments,
11 non-utility plant, and retired plant. This resulted in a Texas test year-end ADIT
12 liability of \$35,774,897. Offsetting this ADIT liability is an ADIT asset attributable
13 to CIACs being taxable when they are received but amortized over their useful life
14 for ratemaking purposes. Multiplying the Texas net CIACs at test year-end of
15 \$23,143,350 described earlier by a 21% tax rate produced an ADIT asset of
16 \$4,860,104. Subtracting the Texas ADIT asset from the Texas ADIT liability
17 resulted in a net Texas ADIT liability of \$25,703,718, which is deducted from
18 Texas rate base on Schedule C.

19 **Q. WHAT IS THE AMOUNT LABELED “EXCESS ADIT” AT THE BOTTOM**
20 **OF SCHEDULE C?**

21 A. Effective January 1, 2018, the federal corporate income tax rate decreased from
22 35% to 21%, and ADIT liability and asset amounts dropped correspondingly.
23 Whereas unregulated firms removed the reductions in ADIT, regulatory authorities,

1 including the Commission, required that the ADIT attributable to the reduction in
2 the corporate income tax rate continued to be carried on a gas utility's books as
3 "excess ADIT." It is then to be amortized over a period generally corresponding to
4 the remaining lives of the assets that gave rise to the excess ADIT.

5 **Q. WHAT IS THE EXCESS ADIT FOR WTGU AT TEST YEAR-END?**

6 A. The excess ADIT at December 31, 2017 was determined in Docket No. OS-20-
7 00004347 to be \$11,836,559, with the ratable amortization of the excess being
8 \$420,839 per year. These calculations are shown in Schedule C-4. At the bottom
9 of Schedule C-4, the excess ADIT is reduced by the six years of amortization
10 between 2018 and 2023 to calculate the net excess ADIT at December 31, 2023 of
11 \$9,311,525, which is deducted from Texas rate base on Schedule C.

12 **Q. WHAT IS WTGU'S TEXAS RATE BASE?**

13 A. Summing the adjusted Texas net plant and working capital, and deducting non-
14 investor supplied capital, all as discussed above, results in Texas rate base of
15 \$119,850,523, as shown at the bottom of Schedule C.

16 **E. Depreciation Expense**

17 **Q. WHAT DEPRECIATION EXPENSE DID WTGU ACCRUE DURING THE**
18 **TEST YEAR?**

19 A. During 2023, WTGU booked net depreciation and amortization expense totaling
20 \$6,112,656. This includes depreciation and amortization expense on Oklahoma
21 plant, intangible plant, CIACs, and plant in service for only a partial year. On
22 Schedule D, the depreciation rates approved in Docket No. OS-20-00004347 are
23 applied to the test year-end adjusted Texas plant balances developed in Schedule
24 C-1, which produces annual depreciation expense of \$5,867,672.

1 **Q. IS THIS THE DEPRECIATION EXPENSE INCLUDED IN WTGU'S**
2 **TEXAS REVENUE REQUIREMENTS?**

3 A. No. Mr. Watson is recommending revised depreciation rates for WTGU. In the
4 last column of Schedule D, Mr. Watson's recommended depreciation rates for each
5 FERC plant account are applied to WTGU's adjusted Texas plant balances to
6 calculate depreciation expense by plant account. The sum of the plant depreciation
7 expenses, less the amortization of CIACs, produces net adjusted depreciation
8 expense of \$5,211,043, which is included in Texas revenue requirements on
9 Schedule A.

10 **F. Return on Investment and Income Taxes**

11 **Q. WHAT RATE OF RETURN IS WTGU REQUESTING?**

12 A. Developed in the last section of my testimony and on Schedule E, WTGU is
13 requesting an overall rate of return of 8.10% be used to determine its cost of
14 providing service in this case and in subsequent GRIP filings. This rate of return
15 is based on capital structure ratios of 34.40% debt and 65.60% equity, a cost of debt
16 of 3.06%, and a rate of return on equity of 10.75%.

17 **Q. WHAT RETURN ON INVESTMENT IS INCLUDED IN WTGU REVENUE**
18 **REQUIREMENTS?**

19 A. As shown in the upper portion of Schedule F, multiplying WTGU's Texas rate base
20 of \$119,850,523 from Schedule C by its requested 8.10% overall rate of return from
21 Schedule E produces a return on investment of \$9,713,453. These same
22 calculations are also shown on Schedule A, where the \$9,713,453 return on
23 investment is included in Texas revenue requirements.

1 **Q. WHAT FEDERAL INCOME TAXES ARE ASSOCIATED WITH THIS**
2 **RETURN?**

3 A. As developed in the middle of Schedule F, the after-tax equity return included in
4 WTGU's requested return on investment is \$8,451,859. This amount is reduced by
5 the \$420,839 annual ratable amortization of excess ADIT developed in Schedule C-
6 4 to arrive at an adjusted after-tax equity return of \$8,031,020. Multiplying this
7 adjusted after-tax equity return by a gross-up factor of 1.265823 (i.e., $1 / (1 -$
8 $\text{income tax rate})$) produces taxable income of \$10,165,848. This taxable income is
9 then multiplied by the statutory corporate tax rate of 21% to calculate an income
10 tax expense of \$2,134,828.

11 **Q. IS THIS THE INCOME TAX EXPENSE INCLUDED IN WTGU'S**
12 **REVENUE REQUIREMENTS?**

13 A. No. This income tax expense is reduced by the ratable amortization of excess ADIT
14 so as to credit this annual amortization amount to determine cost of service rates.
15 Accordingly, reducing the income tax expense of \$2,134,828 by the annual
16 amortization calculated on Schedule C-4 of \$420,839 results in a net income tax
17 expense of \$1,713,989, which is included in Texas revenue requirements on
18 Schedule A.

19 **G. Other Income**

20 **Q. WHAT OTHER INCOME DID WTGU RECEIVE DURING THE TEST**
21 **YEAR?**

22 A. Summarized on Schedule G-1 and shown by month on Schedule G, WTGU
23 received income from other services and activities during calendar year 2023
24 totaling \$1,293,066. The only adjustments to this other income were to remove

1 amounts attributable to Oklahoma operations. As shown on Schedule G-1, sources
2 of other income that could be identified with Oklahoma were removed directly,
3 with a portion of the other income that was received in both states being allocated
4 to Oklahoma based on the 16.32% customer percentage shown on Schedule B-4.

5 **Q. WHAT OTHER INCOME IS DEDUCTED FROM WTGU’S TEXAS**
6 **REVENUE REQUIREMENTS?**

7 A. After removing direct and allocated other income attributable to Oklahoma, the
8 remaining other income shown at the bottom of Schedule G-1 of \$1,087,324 is
9 deducted from Texas revenue requirements on Schedule A.

10 **H. Total Revenue Requirements**

11 **Q. WHAT ARE WTGU’S TOTAL TEXAS REVENUE REQUIREMENTS?**

12 A. As summarized on Schedule A under the heading “Adjusted Texas Amounts,”
13 summing the O&M expenses, A&G expenses, taxes other than income,
14 depreciation expense, return on investment, income taxes, and other income
15 developed above produces revenue requirements, or a total cost of service, for
16 WTGU’s Texas customers of \$34,616,294.

17 **III. COST OF SERVICE STUDY**

18 **A. Overview**

19 **Q. WHAT IS THE PURPOSE OF THIS SECTION?**

20 A. The purpose of this section is to present a COSS that allocates WTGU’s Texas
21 revenue requirements, developed on Schedule A, between its Jurisdictional
22 Domestic and Non-Domestic customer classes, and its Non-Jurisdictional customer
23 class. The results of the COSS provide the basis to develop cost-based rates for
24 WTGU’s Jurisdictional Domestic and Non-Domestic customers.

1 **Q. WOULD YOU BRIEFLY DESCRIBE A COSS?**

2 A. A COSS is an engineering, accounting, and economic analysis designed to allocate
3 a utility's total cost of providing service to specific customers or customer classes.
4 Although some operating and capital costs can be attributed to one or more specific
5 customer classes, most of a utility's operating expenses, except gas costs, and
6 capital investment is incurred to serve all customers, to a greater or lesser extent.
7 Because the joint and common costs cannot be directly tied to specific customers
8 or customer classes, they must be apportioned among all customers and/or customer
9 classes. This apportionment and assignment is accomplished through a COSS, in
10 which operating, and capital costs are allocated using factors developed from
11 various operating data reflecting cost causation. The sum of the costs allocated to
12 each customer and/or customer class in the COSS represents class revenue
13 requirements, or that portion of the utility's total costs for which a particular
14 customer or customer class is responsible.

15 **Q. WHAT GUIDED YOUR COSS?**

16 A. The COSS follows the methodology used to allocate costs between customer
17 classes in WTGU's last two rate cases, with two exceptions. The first relates to the
18 identification of plant between that used to serve all customers ("Joint"), only
19 Jurisdictional customers ("Jurisdictional"), or only Non-Jurisdictional customers
20 ("Non-Jurisdictional"). The second relates to the minimum size of pipe used to
21 classify certain plant and accumulated depreciation between customer- and
22 capacity-related costs. Other than these two exceptions, which I discuss more
23 below, the Texas operating expenses and capital costs developed earlier to calculate

1 Texas revenue requirements are classified and allocated in the same way as in GUD
2 No. 10235 and Docket No. OS-20-00004347.

3 **Q. WHAT WAS THE INITIAL STEP IN CONDUCTING THE COSS?**

4 A. The first step was to identify the amount of each component comprising WTGU's
5 Texas revenue requirements of \$34,616,294. The first numerical column of
6 Schedule J-1 provides the detail of each item of WTGU's Texas revenue
7 requirements, including rate base (i.e., plant in service, accumulated depreciation,
8 working capital items, non-investor supplied capital), operating expenses (i.e.,
9 O&M, A&G, and taxes other than income), capital costs (i.e., depreciation expense,
10 return on investment, and net income taxes), and other income by FERC account
11 and dollar amount. As shown on page 2 of 4 of Schedule J-1, the rate base
12 components in the COSS sum to the \$119,850,523 developed on Schedule C, and
13 on page 3 of 4, the components of revenue requirements sum to the total on
14 Schedule A of \$34,616,294.

15 **Q. WHAT WAS THE NEXT STEP IN CONDUCTING THE COSS?**

16 A. In the COSS in GUD No. 10235 and Docket No. OS-20-00004347, all of WTGU's
17 investment in property, plant, and equipment was treated as joint and common (i.e.,
18 used to serve all customers), with a portion of all plant being allocated to both
19 Jurisdictional and Non-Jurisdictional customers. As explained in the testimonies
20 of Ms. Edgmon and Jack J. King, this treatment ignores that much of WTGU's
21 dispersed investment can be specifically identified with serving only Jurisdictional
22 or only Non-Jurisdictional customers. Aside from WTGU not recovering the full
23 cost of investment discussed by Mr. King, the failure to recognize in the COSS that

1 specific plant amounts were incurred to serve, and only benefit, certain customers
2 violates the fundamental ratemaking principle that customers causing a cost should
3 pay for that cost, and that a customer's rates should reflect only the costs incurred
4 to serve that customer. Conversely, allocating a portion of the costs incurred to
5 serve only one class of customers (e.g., jurisdictional) to another class (e.g., non-
6 jurisdictional) results in cross-subsidizations between the classes. To remedy the
7 distortions and unintended consequences of treating all plant as Joint and to allocate
8 WTGU's costs among its customers more accurately, I modified the prior COSS
9 and assigned plant identified as being used to serve only a particular customer class
10 directly to that class.

11 **Q. HOW WAS THIS DONE?**

12 A. Ms. Edgmon reviewed each WTGU plant addition since 2014. Those additions that
13 served only Jurisdictional and only Non-Jurisdictional customers were identified as
14 such, with the remaining post-2014 additions and all investment prior to 2014 being
15 considered Joint plant. She then determined the total cost and associated
16 accumulated depreciation at test year-end of the 2014-2023 Jurisdictional and Non-
17 Jurisdictional plant additions. These are shown in the third and fourth columns on
18 Schedule J-1, with the second column reflecting the cost and accumulated
19 depreciation of all other plant treated as Joint.

20 **B. Cost Classification**

21 **Q. WHAT WAS THE NEXT STEP IN THE COSS?**

22 A. Having identified the components of revenue requirements, including Joint,
23 Jurisdictional, and Non-Jurisdictional plant and accumulated depreciation, the next
24 step was to determine what portion of each item of the revenue requirements is

1 customer-related, capacity-related, and/or commodity-related. Because WTGU's
2 Texas revenue requirements exclude gas costs, which are recovered separately
3 through its GCA, no portion of its costs are commodity-related costs, which means
4 all costs are customer- and/or capacity-related.

5 **Q. HOW ARE COSTS CLASSIFIED BETWEEN CUSTOMER- AND**
6 **CAPACITY-RELATED?**

7 A. In WTGU's COSS, capital and operating costs are classified between customer-
8 and capacity-related based on two primary classification factors. These primary
9 classification factors determine the proportion of the cost of facilities (i.e., pipe and
10 meters) required to serve customers irrespective of their average or peak use of the
11 system and are classified as customer-related costs. The remaining portion of the
12 cost of facilities is considered necessary to meet customer needs above the
13 minimum required to serve them, and those costs are classified as capacity-related
14 costs.

15 **Q. PLEASE DESCRIBE HOW THE FIRST PRIMARY CLASSIFICATION**
16 **FACTOR WAS DEVELOPED.**

17 A. The first classification factor, referred to as "Pipe" in Schedule J-1, is developed on
18 Schedule J-3. WTGU witness Matthew Smith identified the total number feet of
19 pipe by diameter comprising the WTGU system from plant records. He then
20 estimated the replacement cost per foot for each size of pipe. Using Mr. Smith's
21 data, I calculated the total cost of replacing the pipe on the WTGU system to be
22 approximately \$729.9 million. I also calculated that the cost of replacing the pipe
23 on the WTGU system with a minimum 2-inch pipe would be approximately \$435.6

1 million. Dividing the \$435.6 million cost of a 2-inch pipe system by the \$729.9
2 million total replacement cost of WTGU’s pipe indicates that 59.68% of pipe costs
3 are customer-related, with the remaining 40.32% being capacity-related.

4 **Q. IS THIS “PIPE” CLASSIFICATION CALCULATED ON SCHEDULE J-3**
5 **THE SAME AS IN GUD NO. 10235 AND DOCKET NO. OS-20-00004347?**

6 A. In GUD No. 10235, the same 2-inch pipe was used as the minimum pipe size, but
7 in Docket No. OS-20-00004347, I chose to use 1-inch pipe as the minimum size
8 pipe explicitly to moderate cost shifts between customer classes. I now propose to
9 return to the 2-inch minimum pipe size to calculate the "Pipe" classification factor,
10 which has been approved as the standard minimum pipe size by the Commission
11 for Atmos Energy and CenterPoint Energy.¹

12 **Q. PLEASE DESCRIBE HOW THE SECOND PRIMARY CLASSIFICATION**
13 **FACTOR WAS DEVELOPED.**

14 A. The second classification factor, referred to as “Meters” in Schedule J-1, is
15 developed on Schedule J-4. WTGU witness Smith identified the total number of
16 services by customer type and then estimated the cost to install a meter and riser
17 for each. Using this data, I calculated the total cost of replacing all the meters and

¹ *E.g., Statement of Intent of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas to Increase Rates on a Division-Wide Basis in the Houston Division, GUD No. 9902 consol., Final Order Nunc Pro Tunc at Finding of Fact No. 92 (May 4, 2010) (“The proposed minimum system study based on two-inch pipe is just and reasonable and consistent with precedent of the Railroad Commission”); Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corp., Mid-Tex Division by the City of Dallas; Statement of Intent to Increase Gas Utility Rates in the Unincorporated Areas Served by the Mid-Tex Division, GUD No. 9869 Interim Order at 2-3 (Jul. 14, 2009) (finding that the adoption of a minimum distribution system with two-inch pipe as methodology for cost allocation was reasonable, citing GUD Nos. 9672, 9670, and 9400).*

1 risers on the WTGU system to be \$11.6 million. I also calculated that the cost of
2 replacing the meters and risers on the WTGU system at the cost of a basic
3 residential meter and riser to be \$8.2 million. Dividing the \$8.2 million cost of a
4 system with only basic residential meters by the \$11.6 million total cost of the
5 system with different sized meters and risers indicates that 71.02% of meter costs
6 are customer-related, with the remaining 28.98% being capacity-related.

7 **Q. WERE THESE PRIMARY CLASSIFICATION FACTORS USED TO**
8 **DEVELOP ANOTHER CLASSIFICATION FACTOR?**

9 A. Yes. As shown on page 3 of Schedule J-1, an “Aggregate” classification factor was
10 developed using the data developed in Schedules J-3 and J-4. The Aggregate
11 classification factor combines the pipe and meter costs of a minimum system and
12 divides it by the total replacement cost of pipe and meters on the WTGU system.
13 This Aggregate classification factor classifies 59.85% of costs as customer-related
14 and the remaining 40.15% as capacity-related.

15 **Q. WHAT WAS THE NEXT STEP IN THE COSS?**

16 A. Having developed the Pipe, Meter, and Aggregate classification factors, the next
17 step was to apply these factors to the three plant in service and accumulated
18 depreciation categories (i.e., Joint, Jurisdictional, and Non-Jurisdictional) and
19 O&M expense accounts as in the COSS in GUD No. 10235 and Docket No. OS-
20 20-00004347. The accounts to which these three classification factors were applied
21 can be identified by reference to the “Classification Factor” column in Schedule J-
22 1. Based on the amounts classified as customer- and capacity-related in these

1 accounts, eight additional classification factors were developed. These are shown
 2 on pages 3 and 4 of Schedule J-1.

3 **Q. HOW WERE THESE OTHER CLASSIFICATION FACTORS USED?**

4 A. The various other classification factors were then applied to the remaining rate base,
 5 O&M expense, A&G expense, taxes other than income, return on investment, and
 6 income taxes accounts to classify these capital and operating costs between
 7 customer- and capacity-related and to apportion them between Joint, Jurisdictional-
 8 Only, and Non-Jurisdictional-Only costs. The classification factor applied to each
 9 account is identified in the “Classification Factor” column in Schedule J-1.

10 **Q. WHAT ARE THE RESULTS OF THE CLASSIFICATION OF COSTS IN**
 11 **THE COSS?**

12 A Applying the applicable classification factor to each component of rate base (i.e.,
 13 plant in service, accumulated depreciation, working capital items, non-investor
 14 supplied capital), operating expenses (i.e., O&M, A&G, and taxes other than
 15 income), capital costs (i.e., depreciation expense, return on investment, and net
 16 income taxes), and other income results in the Joint, Jurisdictional-Only, and Non-
 17 Jurisdictional-Only costs being classified between customer and capacity as
 18 follows, and which total Texas revenue requirements of \$34,616,294 on
 19 Schedule A.

Costs	Customer- Related	Capacity- Related	Total
Joint	\$ 12,106,686	\$ 7,999,622	\$ 20,106,308
Jurisdictional-Only	7,972,003	5,323,462	13,295,464
Non-Jurisdictional-Only	731,453	483,070	1,214,522
Total	\$ 20,810,141	\$ 13,806,153	\$ 34,616,294

1 **C. Cost Allocation**

2 **Q. HAVING CLASSIFIED COSTS BETWEEN CUSTOMER- AND**
 3 **CAPACITY-RELATED AND BETWEEN JOINT, JURISDICTIONAL-**
 4 **ONLY, AND NON-JURISDICTIONAL-ONLY, WHAT WAS THE NEXT**
 5 **STEP IN THE COSS?**

6 A. Having identified and classified Joint, Jurisdictional-Only, and Non-Jurisdictional-
 7 Only costs, the next step in conducting WTGU’s COSS was to allocate the
 8 respective customer- and capacity-related costs between WTGU’s three customer
 9 classes: (1) Jurisdictional Domestic, (2) Jurisdictional Non-Domestic, and (3) Non-
 10 Jurisdictional. Initially, three primary allocation factors were developed: Customer
 11 Count, Design Day, and Throughput.

12 **Q. WHAT ARE THE DIFFERENT CUSTOMERS ON THE WTGU SYSTEM?**

13 A. WTGU’s Texas customers are regarded as either “Jurisdictional,” which means
 14 their rates are established in rate proceedings by either municipalities or the
 15 Commission, or “Non-Jurisdictional”, where their rates are negotiated. As shown
 16 in the table below, there are four types of jurisdictional customers, which are
 17 grouped into two customer classes for rate purposes: (1) Domestic, which consists
 18 of residential customers, and (2) Non-Domestic, which consists of the three other
 19 types of customers. There are eight types of Non-Jurisdictional customers, which
 20 for ratemaking purposes, are treated as a single customer class.

Jurisdictional		Non-Jurisdictional	
<u>Domestic</u> Residential	<u>Non-Domestic</u> Public authority Small commercial Large commercial	Public authority Interstate Small commercial Large commercial	Irrigation Resale Transportation Gathering

1 Additional details on WTGU’s customers are presented in Schedule K.

2 **Q. PLEASE DESCRIBE THE CUSTOMER COUNT ALLOCATION FACTOR.**

3 A. Customer Count is the number of customers in each customer class and is used to
4 allocate some customer-related costs between customer classes. The Customer
5 Count allocation factor was based on the average number of jurisdictional Domestic
6 and Non-Domestic customers and Non-Jurisdictional customers during the test
7 year. It was also used for billing units to calculate rates.

8 **Q. WHAT IS THE DESIGN DAY ALLOCATION FACTOR?**

9 A. The Design Day allocation factor is used to allocate some capacity-related costs
10 between customer classes and is intended to reflect the portion of maximum
11 demand that a customer class might place on the system. The Design Day
12 allocation factor is developed on Schedule J-5. I used the same design day heating
13 degree days (“HDDs”) determined in GUD No. 10235 for WTGU’s North, West,
14 and South Zones, but applied them to adjusted 2023 test year peak month
15 throughput (Schedules K-1 through K-3, respectively). The design days of the three
16 zones were then combined to arrive at the Design Day allocation factor for each
17 customer class. The Design Day allocation factor was also adjusted to include the
18 average day demand of irrigation customers, as was done in WTGU’s previous two
19 rate cases.

20 **Q. WHAT IS THE THROUGHPUT ALLOCATION FACTOR?**

21 A. The Throughput allocation factor is used to allocate a limited number of customer-
22 and capacity-related costs based on the relative volumes of gas used by each

1 customer class. Except for customers that have heating-sensitive usage, which was
2 normalized, the throughput allocation factor was based on test year volumes.

3 **Q. PLEASE DESCRIBE HOW YOU NORMALIZED TEST YEAR**
4 **THROUGHPUT FOR HEATING SENSITIVE CUSTOMERS.**

5 A. Actual volumes during 2023 were weather normalized for Domestic, Public
6 Authority, Small Commercial, and Large Commercial customers using the same
7 methodology as in GUD No. 10235 and Docket No. OS-20-00004347, and as
8 described in the Commission's *Natural Gas Rate Review Handbook*. Separate
9 analyses were performed for customers in WTGU's North, West, and South Zones
10 using different average HDDs for each zone. The weather normalization
11 calculations are developed on Schedules K-4, K-5, and K-6 for the respective zones,
12 with Schedules K-7, K-8, and K-9 containing unadjusted monthly data for each
13 customer class and Schedules K-1, K-2, and K-3 presenting monthly weather
14 adjusted volumes by customer class. The volume and customer count data
15 contained in Schedules K-1 through K-9 is summarized for the test year on
16 Schedule K, which also serves as the source of the billing units used to calculate
17 rates for jurisdictional Domestic and Non-Domestic customers.

18 **Q. IS THE USAGE OF ANY OTHER TYPE OF CUSTOMER AFFECTED BY**
19 **WEATHER?**

20 A. Yes. Rainfall affects the amount of gas used by irrigation customers. In GUD
21 No. 10235, test year volumes for irrigation customers were normalized by using a
22 four-year average. However, a review of usage by irrigation customers indicated
23 that the average over the last four years was not appreciably different from test year

1 usage. Because there is not a clearly better measure of representative usage,
2 irrigation customers' test year volumes were used in developing the Throughput
3 allocation factor in this case, as was done in Docket No. OS-20-00004347.

4 **Q. WHAT WAS THE NEXT STEP IN THE COSS?**

5 A. Having developed the Customer Count, Design Day, and Throughput data, the next
6 step was to develop allocation factors applicable to the customer- and capacity-
7 related costs of the Joint, Jurisdictional-Only, and Non-Jurisdictional-Only costs
8 consistent with the COSS in GUD No. 10235 and Docket No. OS-20-00004347.
9 When two allocation factors are identified (e.g., Customer/DD), the first is applied
10 to customer-related costs and the second to capacity-related costs. Based on the
11 amounts allocated to each of the three customer classes in these accounts, eight
12 allocation factors were developed. These are shown on pages 3 and 4 of Schedule
13 J-2. The allocation factor applied to each account is identified in the "Cost
14 Allocation Factor" column in Schedule J-2.

15 **Q. WOULD YOU PLEASE PROVIDE AN EXAMPLE OF HOW THE**
16 **ALLOCATION OF CLASSIFIED COSTS WAS PERFORMED?**

17 A. Yes. Consider Account No. 367 (Transmission Mains). WTGU has a total
18 investment in transmission mains of \$45.3 million, of which \$36.6 million is Joint,
19 \$7.8 million is Jurisdictional-Only, and \$0.9 million is Non-Jurisdictional-Only.
20 For this account, both customer- and capacity-related costs are allocated using the
21 Design Day factor, which is based on a Design Day for Domestic jurisdictional
22 customers of 20,593 Mcf, 15,074 Mcf for Non-Domestic jurisdictional customers,
23 and 105,970 Mcf for Non-Jurisdictional customers, or a total of 141,637 Mcf. Of

1 the \$36.6 million in Joint plant, Domestic jurisdictional customers are allocated
2 14.54% (20,593 Mcf divided by 141,637 Mcf), or \$5.3 million. Non-Domestic
3 jurisdictional customers are allocated 10.64% of the \$36.6 million, or \$3.9 million.
4 The remaining 74.82%, or \$27.4 million, is allocated to Non-Jurisdictional
5 customers. Next, the \$7.8 million in Jurisdictional-Only plant is allocated between
6 just the Domestic and Non-Domestic jurisdictional classes. Domestic jurisdictional
7 customers are allocated 57.75% (20,593 Mcf divided by 35,667 Mcf), or \$4.5
8 million, and Non-Domestic jurisdictional customers are allocated the remaining
9 42.26% (15,074 Mcf divided by 35,667 Mcf) of the \$7.8 million, or \$3.3 million.
10 Finally, the \$0.9 million in Non-Jurisdictional-Only transmission mains is allocated
11 100% to Non-Jurisdictional customers, with none being allocated to Domestic or
12 Non-Domestic jurisdictional customers. The end–result is that, of the \$45.3 million
13 in transmission mains, Domestic jurisdictional customers are allocated a total of
14 \$9.8 million (\$5.3 million of Joint plant, plus \$4.5 million of Jurisdictional-Only
15 plant, plus zero of Non-jurisdictional plant). The Non-Domestic jurisdictional class
16 is allocated \$7.2 million (\$3.9 million plus \$3.3 million plus zero, respectively),
17 and the Non-Jurisdictional class is allocated \$28.3 million (\$27.4 million plus zero
18 plus \$0.9 million).

19 **Q. CAN YOU ALSO SHOW THIS ALLOCATION PROCESS IN TABLE**
20 **FORM?**

21 A. Yes. The allocation of the \$43.5 million investment in Account 376 – Transmission
22 Mains between customer classes described above is also summarized in the
23 following table (dollars in millions):

Description	Joint	Jurisdictional Only	Non-Jurisdictional - Only	Total
<u>Plant 376</u>				
Trans. Mains	\$ 36.6	\$ 7.8	\$ 0.9	\$ 43.5
<u>Design Day</u>				
Domestic-Juris.	14.54%	57.75%	00.00%	20,593
Non-Dom.-Juris.	10.64%	42.26%	00.00%	15,074
Non-Juris.	74.82%	00.00%	100.00%	105,970
<u>Allocated Costs</u>				
Domestic-Juris.	\$ 5.3	\$ 4.5	--	\$ 9.8
Non-Dom.-Juris.	\$ 3.9	\$ 3.3	--	\$ 7.2
Non-Juris.	\$ 27.4	--	\$ 0.9	\$ 28.3
Totals	\$ 36.6	\$ 7.8	\$ 0.9	\$ 43.5

1 A similar process to allocate the classified Joint, Jurisdictional-Only, and Non-
2 Jurisdictional-Only costs to each of the three customer classes was applied for each
3 component of rate base and revenue requirements, with the details being contained
4 in Schedule J-2.

5 **D. COSS Results**

6 **Q. WHAT ARE THE RESULTS OF THE COSS?**

7 A. The customer- and capacity-related costs allocated to each of the three customer
8 classes in the COSS are shown on page 3 of Schedule J-2, and are summarized and
9 totaled in the following table:

Costs	Jurisdictional		Non-Jurisdictional
	Domestic	Non-Domestic	
Customer	\$ 15,405,551	\$ 2,470,463	\$ 2,934,127
Capacity	\$ 4,962,159	\$ 3,627,958	\$ 5,216,036
Total	\$ 20,367,710	\$ 6,098,421	\$ 8,150,163

10 The sum of the total costs allocated to each of the three customer classes equals the
11 Texas revenue requirements of \$34,616,294 developed in the previous section.

1 Additionally, the amount of each component of revenue requirements allocated to
2 each customer class in the COSS is shown on Schedule A.

3 **Q. WHAT ARE COST-BASED RATES FOR JURISDICTIONAL**
4 **CUSTOMERS BASED ON THE RESULTS OF THE COSS?**

5 A. The customer- and capacity-related costs for Domestic and Non-Domestic
6 jurisdictional customers shown above are converted to cost-based rates on Schedule
7 A-1. For Domestic customers, the \$15.4 million in customer-related costs are
8 divided by the 17,924 average number of customers during the test year and 12
9 months, which produces a monthly customer charge of \$71.63. Dividing the \$5.0
10 million of capacity-related costs by adjusted test year volumes produces a
11 consumption charge of \$4.67 per Mcf. Similar calculations for Non-Domestic
12 customers produce a monthly customer charge for this class of \$82.89 and a
13 consumption charge of \$9.61 per Mcf.

14 **Q. HOW DO THESE COST-BASED RATES COMPARE WITH CURRENT**
15 **RATES?**

16 A. Schedule A-2 and the following table compare WTGU's current rates, which
17 include WTGU's pending requested GRIP charge, for Domestic and Non-Domestic
18 customers with cost-based rates:

Description	Current Rates	Cost-Based Rates	Percentage Change
<u>Domestic Customers</u>			
Customer Charge	\$ 23.42	\$ 71.63	205.8%
Commodity Charge (Mcf)	\$ 4.84	\$ 4.67	-3.6%
<u>Non-Domestic Customers</u>			
Customer Charge	\$ 43.57	\$ 82.89	90.2%
Commodity Charge (Mcf)	\$ 2.69	\$ 9.61	257.4%

1 **Q. IS WTGU REQUESTING THAT THE COMMISSION APPROVE THESE**
2 **COST-BASED RATES?**

3 A. No. Because of the overall magnitude of the increases required to charge cost-
4 based rates and the distortions to the structure of existing rates, WTGU is requesting
5 that the Commission approve rates for Domestic customers consisting of a \$29.50
6 monthly customer charge and a \$7.68 per Mcf consumption charge, and for Non-
7 Domestic customers a monthly charge of \$79.00 and a consumption charge of \$4.89
8 per Mcf. These requested rates are compared to existing rates in the following table
9 and on Schedule A-2:

Description	Current Rates	Requested Rates	Percentage Change
<u>Domestic Customers</u>			
Customer Charge	\$ 23.42	\$ 29.50	26.0%
Commodity Charge (Mcf)	\$ 4.84	\$ 7.68	58.7%
<u>Non-Domestic Customers</u>			
Customer Charge	\$ 43.57	\$ 79.00	81.3%
Commodity Charge (Mcf)	\$ 2.69	\$ 4.89	81.8%

10 As shown at the bottom of Schedule A, WTGU's requested rates represent an
11 increase in revenues from Domestic customers of \$4,327,298, or 42.5%, and from
12 Non-Domestic customers of \$2,451,592, or 81.6%.

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IV. RATE OF RETURN

A. Introduction

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. The purpose of this section is to develop an overall rate of return to apply to WTGU’s invested capital, or rate base, to be used to determine its cost of providing service and for interim rate adjustment, or GRIP, filings.

Q. WHAT IS THE ROLE OF RATE OF RETURN IN SETTING A UTILITY’S RATES?

A. Rate of return serves to compensate investors for the use of their capital to finance the plant and equipment necessary to provide utility service to customers. Investors only commit money in anticipation of earning a return on their investment commensurate with that from other investment alternatives having comparable risks. Consistent with both sound regulatory economics and the standards specified in the U.S. Supreme Court cases of *Bluefield Water Works & Improvement Co.* (1923) and *Hope Natural Gas Co.* (1944),² rates should provide the utility a reasonable opportunity to earn a rate of return sufficient to: 1) fairly compensate capital presently invested in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility’s financial integrity.

² *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm’n of W. Va.*, 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923); *Fed. Power Comm’n v. Hope Nat. Gas Co.*, 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944).

1 **Q. IN GENERAL, HOW HAVE YOU GONE ABOUT DEVELOPING YOUR**
2 **RECOMMENDED RATE OF RETURN FOR WTGU?**

3 A. My evaluation begins with brief reviews of the operations and finances of WTGU,
4 its parent WTG Downstream Holdings LLC (“WTG Downstream”), and general
5 conditions in the capital markets, including a discussion of the actions the Federal
6 Reserve Board (“Fed”) is taking in response to the increases in the Consumer Price
7 Index (“CPI”). With this background, I next develop a mix of investor-supplied
8 capital (i.e., debt and equity) to be used as capital structure weightings to develop
9 an overall rate of return. An average cost of debt applicable to the debt component
10 of the capital structure is then calculated. Next, various analyses are conducted to
11 determine a fair rate of return on common equity (“ROE”). These analyses include
12 applications of the discounted cash flow (“DCF”) model, capital asset pricing
13 model (“CAPM”), risk premium method, and comparable earnings method to
14 develop a cost of equity range. I then evaluate my recommended ROE for WTGU
15 for reasonableness and combine the capital cost components to calculate my
16 recommended overall rate of return for WTGU.

17 **B. Summary of Conclusions**

18 **Q. WHAT RATE OF RETURN ARE YOU RECOMMENDING FOR WTGU?**

19 A. As developed on Exhibit BHF-1 attached hereto (and in Schedule E of WTGU’s
20 Rate Filing Schedules), I recommend an overall rate of return on WTGU’s invested
21 capital of 8.10%. This rate of return is based on capital structure ratios of 34.40%
22 debt and 65.60% equity, a cost of debt of 3.06%, and an ROE of 10.75%.

1 **Q. WHAT IS THE BASIS FOR THE CAPITAL STRUCTURE RATIOS USED**
2 **TO CALCULATE WTGU'S RATE OF RETURN?**

3 A. The capital structure ratios of 34.40% debt and 65.60% equity are those of WTGU's
4 parent, WTG Downstream, at December 31, 2023. Although WTG Downstream's
5 test year-end debt and equity ratios are lower and higher, respectively, than the
6 capital structure ratios maintained by a proxy group of large, publicly traded local
7 distribution companies ("LDCs") and those ratios approved by the Commission for
8 the larger LDCs in Texas since 2016, they reflect how WTGU is actually financed
9 and correspond to the greater risks of WTG Downstream's relatively smaller size.

10 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED 3.06% COST OF**
11 **DEBT?**

12 A. Consistent with using WTG Downstream's actual capital structure ratios, I
13 recommend that WTG Downstream's actual cost of debt be assigned to the debt
14 component of its capital structure. At test year-end, the weighted average cost of
15 WTG Downstream's debt was 3.06%, which compares with an average cost of debt
16 for the proxy group of publicly traded LDCs of 4.14%.

17 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED ROE OF 10.75%?**

18 A. Based on applications of the DCF, CAPM, risk premium, and comparable earnings
19 methods, I conclude that equity investors in WTGU require a rate of return for the
20 use of their money in the range of 10.25% to 11.25%. For present purposes, I
21 recommend an ROE for WTGU of 10.75%, which is the bottom of my range, be
22 used to determine the cost of providing service and in GRIP filings.

1 **Q. BRIEFLY DESCRIBE WTGU.**

2 A. WTGU is headquartered in Midland, Texas, and operates a gas distribution system
3 that consists of some 5,700 miles of pipe and currently serves approximately 23,500
4 customers in Texas and 4,600 in southwestern Oklahoma. Previously privately held
5 by a single individual, since 2021 WTGU has been owned by WTG Downstream,
6 which is ultimately owned 80% by Stonepeak Infrastructure Partners and 20% by
7 the Estate of James Lee Davis and Family. At December 31, 2023, WTGU had
8 approximately \$225 million in total assets, with all of its financing being provided
9 by WTG Downstream.

10 **Q. BRIEFLY DESCRIBE WTG DOWNSTREAM.**

11 A. WTG Downstream owns entities that are engaged in natural gas distribution (i.e.,
12 WTGU), gas transmission, and gas marketing. At December 31, 2023, WTG
13 Downstream's assets totaled approximately \$489 million, with revenues during
14 2023 totaling slightly more than \$300 million. At year-end 2023, WTG
15 Downstream's permanent financing consisted of \$155 million of unrated, privately
16 placed notes and approximately \$291 million of equity.

17 **Q. HOW DOES WTGU COMPARE IN SIZE WITH THE MAJOR LDCS IN**
18 **TEXAS?**

19 A. In the following table, WTGU is compared to the gas distribution operations of the
20 three largest LDCs serving Texas – Atmos Energy Corporation (“Atmos”),
21 CenterPoint Energy, Inc. (“CenterPoint”), and ONE Gas, Inc. (“ONE Gas”) through
22 its Texas Gas Service (“TGS”) division. Besides their Texas operations, Atmos,
23 CenterPoint, and ONE Gas also have substantial gas distribution activities in other

1 states throughout the U.S., and Atmos and CenterPoint are also involved in other
 2 regulated and unregulated activities (dollar amounts in millions):

Company	Customers		Gas Distribution	
	Texas	U.S.	Revenues	Net Plant
Atmos	2,186,846	3,486,384	\$ 4,097	\$ 14,402
CenterPoint	1,908,946	4,313,954	\$ 4,276	\$ 11,455
ONE Gas	699,000	2,265,000	\$ 2,371	\$ 6,135
WTGU	23,538	28,125	\$ 144	\$ 204

3 **Q. WHAT ARE THE IMPLICATIONS OF THE ABOVE SIZE COMPARISON**
 4 **FOR DETERMINING WTGU’S RATE OF RETURN?**

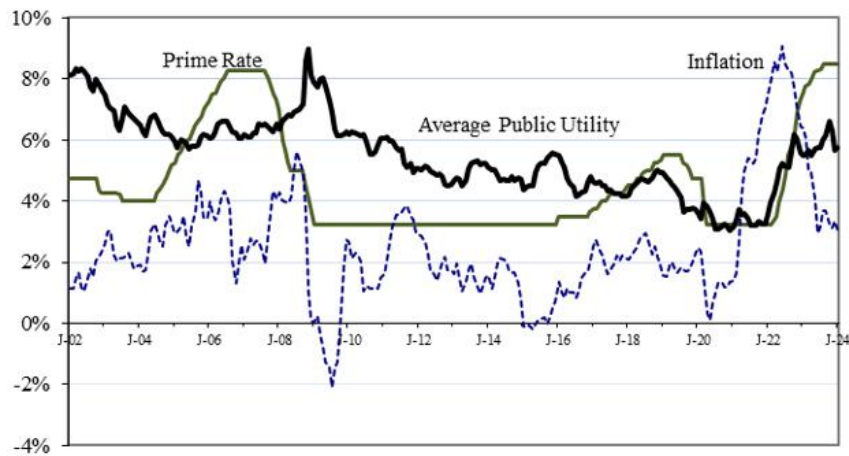
5 A. The significance of the above table is that WTGU is not in the same league as
 6 Atmos, CenterPoint, and TGS. Indeed, the three largest investor-owned utility
 7 (“IOU”) LDCs in Texas are many multiples larger than WTGU, with its number of
 8 customers, revenues, and net plant being dwarfed by those of Atmos, CenterPoint,
 9 and TGS. This size difference affects various aspects of WTGU’s operations and
 10 finances. As a small LDC having widely dispersed service areas and fewer
 11 financial resources, WTGU faces greater operating and financial risks than large
 12 LDCs in Texas and elsewhere. This fundamental fact is properly recognized and
 13 accounted-for in determining a fair rate of return for WTGU.

14 **C. Capital Markets**

15 **Q. WHAT HAS BEEN THE PATTERN OF INTEREST RATES OVER THE**
 16 **LAST TWENTY YEARS?**

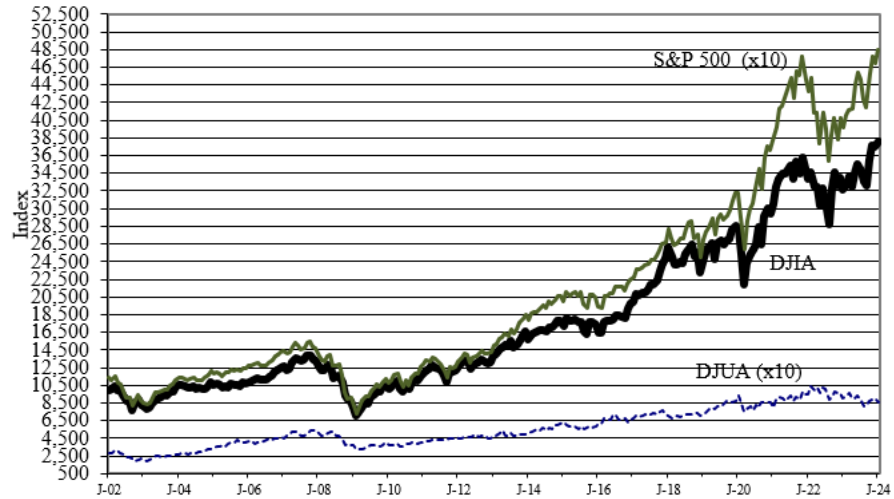
17 A. Average long-term public utility bond rates, the borrowing prime rate, and inflation
 18 as measured by the CPI over the last approximately twenty years are plotted in the
 19 graph below. Beginning in 2002, the average yield on long-term public utility
 20 bonds generally fell because of monetary and fiscal policies designed to keep the

1 economy growing. This decline ended abruptly with the 2008 financial market
2 meltdown and global recession. Investors became exceedingly risk averse, causing
3 interest rates on corporate bonds to spike, while government policies pushed down
4 short-term interest rates and depressed economic conditions and lower energy
5 prices reduced inflation. Over the next decade, various actions by the Fed to
6 stimulate the economy through easy-money policies resulted in short- and long-
7 term interest rates reaching record lows. These conditions were interrupted in early
8 2020 by the coronavirus pandemic and worldwide economic shutdown, although
9 the impact on interest rates was moderated by extraordinary actions taken by the
10 Fed in response. However, in late 2021 CPI inflation began to skyrocket, jumping
11 from an average of around 2% over the prior 20 years to 7% in 2021, peaking at
12 over 9% in June 2022, and since the third quarter of 2023 ranging between 3.0%
13 and 3.5%:



1 **Q. HOW HAS THE MARKET FOR COMMON EQUITY CAPITAL**
2 **PERFORMED OVER THIS SAME PERIOD?**

3 A. In the early 2000s, stock prices moved steadily higher as one of the longest bull
4 markets in U.S. history continued unabated. In mid-2000, mounting concerns over
5 prospects for future growth, particularly for firms in the high technology and
6 telecommunications sectors, pushed equity prices lower, in some cases
7 precipitously. Common stock prices generally recovered and reached record highs,
8 buoyed in large part by widespread acquisition activity, until the capital market
9 crisis and Great Recession occurred in 2008. Stock prices tumbled by some 40%,
10 and while they recovered and reached all-time highs over the next decade, they
11 crashed again in early 2020 due to the coronavirus pandemic. Since then, most
12 stock indices reached all-time highs, but subsequently receded some 20% into bear
13 market territory in response to inflation worries, soaring energy prices, and global
14 events (e.g., the Russian invasion of Ukraine). They have recently fully recovered
15 as inflation has abated and investors expect the Fed to discontinue hiking interest
16 rates. Additionally, the stock market has become extraordinarily volatile, with
17 share prices routinely changing more than full percentage points during a single
18 day's trading. The graph below plots the performances of the Dow-Jones Industrial
19 Average, the S&P 500, and the Dow Jones Utility Average since 2002 (the latter
20 two indices were scaled for comparability):



1 **Q. WHAT IS THE CURRENT OUTLOOK FOR THE U.S. ECONOMY?**

2 A. The U.S. economy had fully recovered from the Great Recession when the
3 coronavirus pandemic struck in early 2020, and the world economy came to a
4 virtual stand-still. More than 30 million U.S. jobs were lost as a result of the
5 pandemic, and unemployment reached almost 15%, not counting furloughed
6 workers, throwing the U.S. into a recession overnight. To address the crisis, the
7 U.S. Congress provided some \$4.5 trillion in aid and stimulus spending, and the
8 Fed held short-term interest rates near zero and purchased up to \$120 billion a
9 month in Treasury debt and mortgage-backed securities to suppress long-term
10 interest rates. The combined effect of these fiscal and monetary policies, along
11 with the population becoming vaccinated, is that U.S. economic activity
12 subsequently increased to greater than prior to the coronavirus pandemic and
13 unemployment fell to below 4%. As noted earlier, however, inflation began to
14 increase markedly in 2021. After initially attributing the increase to supply-chain
15 problems and then the Russian invasion of Ukraine, the Fed concluded that the
16 dramatic rise in prices was not “transitory,” and beginning in March 2022 it

1 embarked on its most aggressive effort in more than two decades to curb inflation.
2 This included increasing short-term interest rates, announcing that more hikes in
3 the federal funds rate would follow, and reducing its \$9 trillion inventory of
4 Treasury debt and mortgage-backed securities up to \$95 billion a month by not
5 replacing maturing bonds. As inflation moderated in 2023, the Fed indicated that
6 it might begin to reduce interest rates in 2024, but it has not done so because
7 inflation has stubbornly remained above 3% and employment data continues to be
8 strong. Whether the unprecedented actions during 2022-2023 by the Fed will
9 reduce inflation to its target level of 2% is yet unknown. Thus far, they have been
10 only partially successful, with the ultimate outcome remaining a significant
11 uncertainty hanging over all segments of the U.S. economy.

12 **Q. HOW DO THESE UNCERTAINTIES AFFECT THE COST OF CAPITAL?**

13 A. Hikes in the federal funds rate by the Fed and significant reductions in its long-term
14 bond inventory are intended to increase the cost of all borrowing, including by
15 LDCs. As will be explained more later, higher interest rates also increase the cost
16 of more risky equity capital. This, coupled with the greater volatility in stock prices
17 that also increases the risk of investing in common equities, supports the conclusion
18 that the relatively low capital cost environment that has existed for the last decade
19 has ended. As a result, the cost of both debt and equity is expected to remain higher
20 for the foreseeable future, and the ROEs authorized for LDCs over the last few
21 years, including those allowed by this Commission, must be adjusted to recognize
22 the changes in capital markets. Only an ROE that reflects the current capital market

1 conditions faced by LDC’s will fairly compensate a utility’s investors, enable LDCs
2 to attract new capital on reasonable terms, and maintain their financial integrity.

3 **V. CAPITAL STRUCTURE AND COST OF DEBT**

4 **A. Capital Structure**

5 **Q. WHAT ROLE DOES CAPITAL STRUCTURE PLAY IN DEVELOPING A**
6 **UTILITY’S RATE OF RETURN?**

7 A. A utility’s capital structure reflects the mix of permanent capital – debt, preferred
8 stock (if any), and common equity – used to finance the utility’s assets. The
9 proportions of a utility’s total capitalization attributable to each source of
10 permanent capital are typically used to weight the cost of debt, cost of preferred
11 stock, and ROE in calculating an overall rate of return.

12 **Q. WHAT SOURCES OF CAPITAL ARE USED TO FINANCE WTGU’S**
13 **INVESTMENT IN UTILITY ASSETS?**

14 A. As noted earlier, WTGU relies entirely on capital supplied by WTG Downstream
15 to finance its investment in assets. In the following table, WTG Downstream’s
16 December 31, 2023 balance sheet reflects that it is financed with approximately
17 \$152.7 million of debt and \$291.1 million of common equity. Also developed there
18 are WTG Downstream’s test year-end capital structure ratios of 34.40% debt and
19 65.60% equity:

Capital Component	Amount	% of Total
Long-term Debt	\$ 152,670,914	34.40%
Common Equity	291,132,606	65.60%
Total	\$ 443,803,520	100.00%

1 **Q. HOW ARE LDCS TYPICALLY FINANCED?**

2 A. Based on data published by the American Gas Association, the gas distribution
 3 industry had the following composite capital structure ratios between 2018 and
 4 2022:

Capital Component	2022	2021	2020	2019	2018
Long-term Debt	42.8%	43.6%	42.3%	41.0%	41.9%
Preferred Stock	0.0%	0.0%	0.0%	0.9%	0.1%
Common Equity	57.2%	56.4%	57.7%	58.1%	58.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

5 The table above indicates that LDCs as a whole have historically financed
 6 their investment in utility plant with around 42% long-term debt and 58% preferred
 7 and common equity. Alternatively, Exhibit BHF-2 displays the capital structure
 8 ratios at fiscal year-ends 2020 through 2023 for an industry group of publicly traded
 9 LDCs. Beginning with the nine companies included in *The Value Line Investment*
 10 *Survey's* (“*Value Line*”) Natural Gas Utility industry, I excluded Southwest Gas
 11 Holdings, which is in the midst of a restructuring, and UGI Corp., which is not
 12 predominantly engaged in natural gas distribution. This resulted in an industry
 13 group consisting of: 1) Atmos Energy, 2) Chesapeake Utilities, 3) New Jersey
 14 Resources, 4) NiSource, Inc., 5) Northwest Natural Gas, 6) ONE Gas, and 7) Spire,
 15 Inc. While the average debt and equity ratios for this group of publicly traded LDCs
 16 are approximately 50%, the upper end of the equity ratio range for the group is 60%
 17 or above.

1 **Q. WHAT CAPITAL STRUCTURE RATIOS HAS THE COMMISSION**
 2 **APPROVED FOR MAJOR LDCS IN TEXAS?**

3 A. The following table lists the capital structure ratios approved by the Commission
 4 for the three largest LDCs in Texas from 2016 through the present. As shown there,
 5 with but a few exceptions, the equity ratios included in the rates of return authorized
 6 by the Commission have been approximately 60%:

Date	Docket	Utility	Debt	Equity
05/03/2016	10488	TGS – Gulf Coast	39.80%	60.20%
09/27/2016	10506	TGS – West Texas	39.90%	60.10%
11/15/2016	10526	TGS –Central Texas	39.50%	60.50%
05/23/2017	10567	CP Energy– Houston	44.85%	55.15%
12/05/2017	10640	Atmos – Dallas	41.49%	58.51%
03/20/2018	10656	TGS – RGV	38.71%	61.29%
05/22/2018	10669	CP Energy – S. Texas	45.00%	55.00%
11/13/2018	10739	TGS – NTSA	37.84%	62.16%
12/11/2018	10742	Atmos – Mid-Tex	39.82%	60.18%
12/11/2018	10743	Atmos – West Texas	39.82%	60.18%
02/05/2019	10766	TGS – BSSA	37.84%	62.16%
05/21/2019	10779	Atmos – Mid-Tex	39.82%	60.18%
04/21/2020	10900	Atmos – West Texas	39.88%	60.12%
05/21/2019	10920	CP Energy-Beaumont/ETx	43.05%	56.95%
08/04/2020	10928	TGS – CGSA	41.00%	59.00%
01/18/2023	00009896	TGS – WNSA	40.26%	59.74%
01/30/2024	00014399	TGS – RGV	40.93%	59.07%
6/25/2024	00015513	CenterPoint Energy	39.39%	60.61%

7 **Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE**
 8 **USED TO CALCULATE WTGU’S RATE OF RETURN?**

9 A. Although WTG Downstream’s capital structure ratios at December 31, 2023 of
 10 34.40% debt and 65.60% equity are lower and higher, respectively, than industry

1 averages and the approximately 40% debt and 60% equity the Commission has
2 previously allowed the three major LDCs in Texas, they are consistent with the
3 considerably smaller size of WTGU and the greater operating risks it faces because
4 of its dispersed operations throughout West Texas, and that the only collateral for
5 WTG Downstream's debt is its assets and those of subsidiaries. Accordingly, I
6 recommend that WTG Downstream's actual, test year-end capital structure ratios
7 of 34.40% debt and 65.60% equity be used to calculate WTGU's rate of return.

8 **B. Cost of Debt**

9 **Q. PLEASE DESCRIBE WTG DOWNSTREAM'S DEBT.**

10 A. WTG Downstream's debt is a privately placed Note Agreement consisting of three
11 series of senior notes. Series A is a \$55,000,000 note bearing an interest rate of
12 2.36% maturing in 2026. Series B is also a \$55,000,000 note, but carries an interest
13 rate of 2.72% and matures in 2028. Series C is a \$45,000,000 note having an
14 interest rate of 2.99% that matures in 2031. Interest is payable semi-annually and
15 the notes are secured only by the assets of WTG Downstream and its subsidiaries.
16 At December 31, 2023, there remained unamortized debt issuance expenses of
17 \$2,329,086 on the notes.

18 **Q. WHAT IS THE AVERAGE COST OF WTG DOWNSTREAM'S DEBT?**

19 A. As shown below and on Exhibit BHF-3, the weighted average cost of WTG
20 Downstream's debt at December 31, 2023 is 3.06%:

Description	Amount	Interest Rate	Annual Expense
Series A	\$ 55,000,000	2.36%	\$ 1,298,000
Series A	55,000,000	2.72%	1,496,000
Series A	45,000,000	2.99%	1,345,000
Debt Issuance Costs	(2,329,086)		538,746
Total	\$152,670,914		\$4,678,246
Cost of Debt		3.06 %	

1 **Q. HOW DOES WTG DOWNSTREAM'S 3.06% AVERAGE COST OF DEBT**
2 **COMPARE TO THAT OF OTHER LDCS?**

3 A. As shown in the lower portion of Exhibit BHF-3, the average cost of debt for the
4 seven large, publicly traded LDC proxy group described earlier is 4.14%,
5 considerably greater than WTG Downstream's cost of 3.06%.

6 **Q. WHAT COST OF DEBT DO YOU RECOMMEND BE USED TO**
7 **CALCULATE WTGU'S RATE OF RETURN?**

8 A. Consistent with using WTG Downstream's actual capital structure ratios, I
9 recommend that WTG Downstream's test year-end average cost of debt of 3.06%
10 be used to calculate WTGU's rate of return.

11 **VI. RETURN ON EQUITY**

12 **Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

13 A. The purpose of this section is to develop a cost of equity range for WTGU as the
14 basis for selecting the ROE I recommend be used to determine its cost of providing
15 service and in GRIP filings. It begins by introducing the cost of equity concept,
16 explaining the risk-return tradeoff principle fundamental to capital markets, and
17 discussing the importance of using multiple approaches to estimate the cost of

1 equity. The DCF model is then developed and applied to a group of publicly traded
2 LDCs to estimate their costs of equity, which is then adjusted to reflect WTGU's
3 smaller size and greater risk. Next, the CAPM is described and alternative cost of
4 equity estimates for WTGU are developed using this method. WTGU's cost of
5 equity is also estimated using the risk premium method based on authorized ROEs,
6 and a comparable earnings method is applied. The results of these analyses are then
7 combined to arrive at a cost of equity range for WTGU, from which my
8 recommended ROE is selected.

9 **A. Cost of Equity Concept**

10 **Q. HOW IS RATE OF RETURN ON COMMON EQUITY CUSTOMARILY**
11 **DETERMINED?**

12 A. Unlike debt capital, there is no contractually guaranteed return on common equity
13 capital, because shareholders are the residual owners of the utility. Nonetheless,
14 common equity investors still require a return on their investment, with the "cost
15 of equity" being the minimum rent that must be paid for the use of their money.

16 **Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS**
17 **COST OF EQUITY CONCEPT?**

18 A. The cost of equity concept is predicated on the notion that investors are risk averse
19 and willingly accept additional risk only if they expect to be compensated for
20 bearing that risk. In capital markets where relatively risk-free assets are available,
21 such as U.S. Treasury securities, investors can be induced to hold more risky assets
22 only if they are offered a premium, or additional return, above the rate of return on
23 a risk-free asset. Because all assets compete with each other for investors' funds,

1 riskier assets must yield a higher expected rate of return than less risky assets in
2 order for investors to be willing to hold them.

3 Given this risk-return tradeoff, the minimum required rate of return (k) from
4 an asset (i) can be generally expressed as:

$$5 \quad k_i = R_f + RP_i$$

6 where: R_f = Risk-free rate of return; and

7 RP_i = Risk premium required to hold more risky asset i .

8 Thus, the minimum required rate of return for a particular asset at any point in time
9 is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors
10 demanding correspondingly larger risk premiums for assets bearing greater risk.

11 **Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF**
12 **PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?**

13 A. Yes. The risk-return tradeoff can be readily documented in certain segments of the
14 capital markets where required rates of return can be directly inferred from market
15 data and generally accepted measures of risk exist. For example, bond yields are
16 reflective of investors' expected rates of return, and bond ratings are indicative of
17 the risk of fixed income securities. The observed yields on government securities
18 and bonds of various rating categories demonstrate that the risk-return tradeoff
19 does, in fact, exist in the capital markets.

20 To illustrate, average yields during May 2024 on 30-year U.S. Treasury
21 bonds, investment grade public utility bonds of different ratings reported by
22 Moody's Investors Service, and below investment grade double-B corporate bonds
23 derived from data reported by the St. Louis Federal Reserve Bank are shown in the
24 following table. As evidenced there, as risk increases (measured by progressively

1 lower bond ratings), the required rate of return (measured by yields) rises
 2 accordingly. Also shown are the indicated risk premiums over long-term
 3 government securities for the additional risk associated with each bond rating
 4 category:

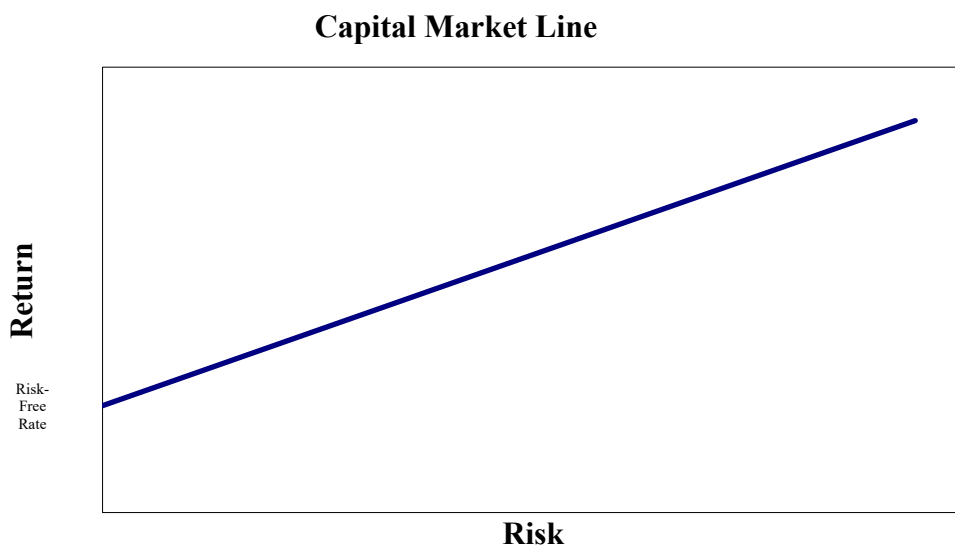
<u>Bond and Rating</u>	<u>May 2024 Yield</u>	<u>Risk Premium Over 30-Year Treasury</u>
U.S. Treasury 30-Year	4.62%	--
Public Utility Aa	5.62%	1.00%
A	5.74%	1.12%
Baa	5.97%	1.35%
Corporate <u>BB</u>	6.42%	1.80%

5 **Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED**
 6 **INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER**
 7 **ASSETS?**

8 A. Documenting the risk-return tradeoff for assets other than fixed income securities
 9 is complicated by two factors. First, there is no standard measure of risk applicable
 10 to all assets. Second, for most assets (e.g., common stock), required rates of return
 11 cannot be directly observed. Yet there is every reason to believe that investors
 12 exhibit risk aversion in deciding whether to hold common stocks and other assets,
 13 just as when choosing among fixed income securities. Accordingly, it is generally
 14 accepted that the risk-return tradeoff evidenced with long-term debt extends to all
 15 assets.

16 The extension of the risk-return tradeoff from assets with observable
 17 required rates of return (e.g., bonds) to other assets is represented by the concept of
 18 a “capital market line.” In particular, competition between securities and among

1 investors in the capital markets drives the prices of assets to equilibrium such that
 2 the expected rate of return from each is commensurate with its risk. Thus, the
 3 expected rate of return from any asset is a risk-free rate of return plus a
 4 corresponding risk premium. This concept of a capital market line is illustrated
 5 below. The vertical axis represents required rates of return and the horizontal axis
 6 indicates relative riskiness, with the intercept of the capital market line being the
 7 risk-free rate of return.



8 **Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO**
 9 **ESTIMATING THE COST OF EQUITY FOR A UTILITY?**

10 A. Although the cost of equity cannot be observed directly, it is a function of the
 11 returns available from other investment alternatives and the risks to which the
 12 equity capital is exposed. Because it is unobservable, the cost of equity for a
 13 particular utility must be estimated by analyzing information about capital market
 14 conditions generally, assessing the relative risks of the utility specifically, and
 15 employing various quantitative methods that focus on investors' required rates of

1 return. These various quantitative methods typically attempt to infer investors'
2 required rates of return from stock prices, by extrapolating interest rates, or through
3 an analysis of other financial data.

4 **Q. DO YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF**
5 **EQUITY FOR WTGU?**

6 A. No. Despite the theoretical appeal of or precedent for using a particular method to
7 estimate the cost of equity, no single approach can be regarded as wholly reliable.
8 Therefore, I use multiple methods to estimate the cost of equity. Indeed, it is
9 essential that estimates of investors' minimum required rate of return produced by
10 one method be compared with those produced by other methods, and that all cost
11 of equity estimates be required to pass fundamental tests of reasonableness and
12 economic logic.

13 **B. Discounted Cash Flow Model**

14 **Q. HOW ARE DCF MODELS USED TO ESTIMATE THE COST OF EQUITY?**

15 A. The use of DCF models to estimate the cost of equity is essentially an attempt to
16 replicate the market valuation process that led to the price investors are willing to
17 pay for a share of a company's common stock. It is predicated on the assumption
18 that investors evaluate the risks and expected rates of return from all securities in
19 the capital markets. Given these expected rates of return, the price of each share of
20 stock is adjusted by the market so that investors are adequately compensated for
21 the risks to which they are exposed. Therefore, we can look to the market to
22 determine what investors believe a share of common stock is worth, and by
23 estimating the cash flows they expect to receive from the stock in the way of future
24 dividends and stock price, their required rate of return can be mathematically

1 imputed. In other words, the cash flows that investors expect from a stock are
 2 estimated, and given the stock’s current market price, we can “back-into” the
 3 discount rate, or cost of equity, investors presumably used in arriving at that price.

4 **Q. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?**

5 A. DCF models are derived from a theory of valuation that posits that the price of a
 6 share of common stock is equal to the present value of the expected cash flows (i.e.,
 7 future dividends and stock price) that will be received while holding the stock,
 8 discounted at investors’ required rate of return, or the cost of equity. Notationally,
 9 the general form of the DCF model is as follows:

10
$$P_0 = \frac{D_1}{(1 + K_e)^1} + \frac{D_2}{(1 + K_e)^2} + \dots + \frac{D_t}{(1 + K_e)^t} + \frac{P_t}{(1 + K_e)^t}$$

11 where: P_0 = Current price per share;
 12 P_t = Future price per share in period t;
 13 D_t = Expected dividend per share in period t;
 14 K_e = Cost of equity.

15 **Q. HAS THIS GENERAL FORM OF THE DCF MODEL CUSTOMARILY**
 16 **BEEN SIMPLIFIED FOR USE IN ESTIMATING THE COST OF EQUITY**
 17 **IN RATE CASES?**

18 A. Yes. In an effort to reduce the number of required estimates and computational
 19 difficulties, the general form of the DCF model has been simplified to a “constant
 20 growth” form. In order to convert the general form of the DCF model to the
 21 constant growth DCF model, a number of assumptions must be made. These
 22 include:

- 23 • A constant growth rate for both dividends and earnings;
- 24 • A stable dividend payout ratio;
- 25 • The discount rate exceeds the growth rate;

- 1 • A constant growth rate for book value and price;
- 2 • A constant earned rate of return on book value;
- 3 • No sales of stock at a price above or below book value;
- 4 • A constant price-earnings ratio;
- 5 • A constant discount rate (i.e., no changes in risk or interest rate
- 6 levels and a flat yield curve); and
- 7 • All of the above extend to infinity.

8 Given these assumptions, the general form of the DCF model can be reduced to the
9 more manageable formula of:

$$10 \quad P_0 = \frac{D_1}{K_e - g}$$

11 where: g = Investors' long-term growth expectations.

12 The cost of equity (“ K_e ”) can be isolated by rearranging terms:

$$13 \quad K_e = \frac{D_1}{P_0} + g$$

14 The constant growth form of the DCF model recognizes that the rate of return to
15 stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In
16 other words, investors expect to receive a portion of their total return in the form of
17 current dividends and the remainder through price appreciation.

18 While the constant growth form of the DCF model provides a more
19 manageable formula to estimate the cost of equity, it is important to note that the
20 assumptions required to convert the general form of the DCF model to the constant
21 growth form are never strictly met in practice. In some instances, where earnings
22 are derived solely from stable activities, and earnings, dividends, and book value
23 track fairly closely, the constant growth form of the DCF model may be a

1 reasonable working approximation of stock valuation. However, in other cases,
2 where the circumstances cause the required assumptions to be severely violated,
3 the constant growth DCF model may produce widely divergent and meaningless
4 results. This is especially the case if the firm's earnings or dividends are unstable,
5 or if investors are expecting the stock price to be affected by factors other than
6 earnings and dividends.

7 **Q. IS THERE ANYTHING ELSE THAT AFFECTS THE USE OF THE DCF**
8 **MODEL TO ESTIMATE INVESTORS' REQUIRED RATE OF RETURN?**

9 A. Yes. When the DCF model came into widespread use as a method to estimate the
10 cost of equity in the 1960s and 1970s, it was regarded as a fair representation of
11 investor behavior and share valuation. Investors bought and sold stocks based on
12 their fundamental underlying value, which was tied to long-term dividend and stock
13 price growth expectations. That is no longer the case. It is estimated that some
14 75% of equities bought and sold on the New York Stock Exchange are now "high
15 frequency" or "algorithmic" trades. These trades are not investors buying stocks
16 for the long-term, but are short-term, computer-initiated trades intended to take
17 advantage of market discrepancies, movements, and information. Accordingly, it
18 is not clear whether common stock prices are now based on the valuation assumed
19 by DCF theory and upon which estimating the cost of equity using the DCF model
20 is predicated.

1 **Q. THESE CAVEATS NOTWITHSTANDING, HOW DID YOU ESTIMATE**
2 **THE COST OF EQUITY USING THE DCF MODEL?**

3 A. Because WTGU has no publicly traded common stock, the DCF model cannot be
4 used to estimate its cost of equity directly. For this reason, and to avoid
5 measurement error associated with applying the DCF model to a single firm, I
6 applied the constant growth form of the DCF model to the proxy group of nine
7 publicly traded LDCs identified earlier. As described earlier, I began with the nine
8 companies included in *Value Line's* Natural Gas Utility industry at May 24, 2024,
9 and then excluded UGI Corp. because it is not predominantly engaged in natural
10 gas distribution and Southwest Gas Holdings because it is in the midst of a major
11 restructuring. This resulted in a proxy group consisting of the seven LDCs listed
12 on Exhibit BHF-4.

13 **Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL USED**
14 **TO ESTIMATE THE COST OF EQUITY?**

15 A. The first step in implementing the constant growth DCF model is to determine the
16 expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated
17 based on an estimate of dividends to be paid in the coming year divided by the
18 current price of the stock.

19 **Q. HOW DID YOU CALCULATE THE DIVIDEND YIELD COMPONENT OF**
20 **THE CONSTANT GROWTH DCF MODEL FOR THE LDC PROXY**
21 **GROUP?**

22 A. Because estimating the cost of equity using the DCF model is an attempt to replicate
23 how investors arrived at an observed stock price, all of its components should be

1 contemporaneous. Price, dividend, and growth data from different points in time,
2 or averaged over long time periods, violate the matching principle underlying the
3 DCF model. Therefore, dividend yield was calculated by dividing an estimate of
4 dividends to be paid by each of the LDCs in the group over the next twelve months,
5 obtained from the index to *Value Line's* May 31, 2024 edition, by the average
6 closing price of each firm's stock during the month of May 2024. The expected
7 dividends, representative price, and resulting dividend yield for each of the seven
8 LDCs are displayed on Exhibit BHF-4. As calculated there, the average dividend
9 yield for the industry group is 3.90%. Also shown is the median for the group of
10 3.88%, which removes the impact of extreme low and high values on the average.

11 **Q. EXPLAIN HOW ESTIMATES OF INVESTORS' LONG-TERM GROWTH**
12 **EXPECTATIONS ARE CUSTOMARILY DEVELOPED FOR USE IN THE**
13 **CONSTANT GROWTH DCF MODEL.**

14 A. In constant growth DCF theory, earnings, dividends, book value, and market price
15 are all assumed to grow in lockstep, and the growth horizon of the DCF model is
16 infinite. But implementation of the DCF model is more than just a theoretical
17 exercise; it is an effort to replicate the mechanism investors used to arrive at
18 observable stock prices. Therefore, the only "g" that matters in using the DCF
19 model to estimate the cost of equity is that which investors expect and have
20 embodied in current market prices.

21 **Q. WHAT DRIVES INVESTORS' GROWTH EXPECTATIONS?**

22 A. Trends in earnings, which ultimately support future dividends and share price, play
23 a pivotal role in determining investors' long-term growth expectations. Security

1 analysts' growth forecasts are generally regarded as the closest single measure of
2 the expected long-term growth rate of the constant growth DCF model. While
3 being primarily based on the outlook for a firm, they also reflect the utility's
4 historical experience and other factors considered by investors in forming their
5 long-term growth expectations. Moreover, various empirical studies have found
6 that security analysts' projections are a superior source of DCF growth rates. The
7 5-year earnings growth projections by security analysts for each of the seven gas
8 utilities reported by *Value Line*, LSEG's Institutional Brokers Estimate System
9 ("I/B/E/S"), and Zacks Investment Research ("Zacks") are displayed on Exhibit
10 BHF-5, with the averages for the group being 6.1%, 7.2%, and 5.8%, respectively.
11 Again, to eliminate the impact of extreme values, the medians for the group are also
12 shown, which range between 5.5% and 7.4%. Also shown on Exhibit BHF-5 are
13 the 10-year and 5-year historical earnings growth rates reported by *Value Line* for
14 each of the seven gas utilities, which average 4.8% and 6.9%, respectively, and
15 have medians of 5.0% and 6.0%, respectively.

16 **Q. HOW ELSE ARE INVESTOR EXPECTATIONS OF FUTURE**
17 **LONG-TERM GROWTH PROSPECTS FOR A FIRM OFTEN**
18 **ESTIMATED FOR USE IN THE CONSTANT GROWTH DCF MODEL?**

19 A. In DCF theory and practice, growth in book equity comes from the reinvestment of
20 earnings within the business and the effects of external financing. Accordingly,
21 conventional applications of the constant growth DCF model often examine the
22 relationships between variables that determine the "sustainable" growth attributable
23 to these two factors.

1 **Q. HOW IS A FIRM'S SUSTAINABLE GROWTH ESTIMATED?**

2 A. The sustainable growth rate is calculated by the formula:

3
$$g = br + sv$$

4 where "b" is the expected earnings retention ratio (one minus the dividend payout
5 ratio), "r" is the expected rate of return earned on book equity, "s" is the percent of
6 common equity expected to be issued annually as new common stock, and "v" is
7 the equity accretion ratio. The "br" term represents the growth from reinvesting
8 earnings within the firm while the "sv" term represents the growth from external
9 financing. This external financing growth results because existing shareholders
10 share in a portion of any excess received from selling new shares at a price above
11 book value.

12 **Q. WHAT GROWTH RATE DOES THE SUSTAINABLE GROWTH METHOD**
13 **SUGGEST FOR THE GAS UTILITY GROUP?**

14 A. The sustainable growth rate for each of the gas utilities in the industry group based
15 on *Value Line's* projections for 2027-2029 is developed in Exhibit BHF-6. As
16 shown there, the sustainable growth method implies an average long-term growth
17 rate for the LDC utility group of 5.7%, and 6.0% based on the median.

18 **Q. WHAT ARE OTHER PROJECTED AND HISTORICAL GROWTH RATES**
19 **FOR THE INDUSTRY GROUP?**

20 A. Exhibit BHF-7 displays *Value Line* projected growth rates and 10- and 5-year
21 historical growth rates in book value per share, dividends per share, and stock price
22 for each of the seven gas utilities in the industry group. The averages for the LDC
23 group range from a negative 2.8% (5-year historical price growth) to 8.7%

1 (projected price growth), with the medians ranging from a negative 2.3% to 9.2%.
2 Besides the fact that some of these growth rates, when combined with the group's
3 approximately 3.90% dividend yield, imply implausible cost of equity estimates,
4 the variation in these other growth rates results in their providing only limited
5 guidance as to the prospective growth that investors expect.

6 **Q. WHAT IS YOUR CONCLUSION AS TO THE LONG-TERM GROWTH**
7 **THAT INVESTORS ARE EXPECTING FROM THE INDUSTRY GROUP?**

8 A. After excluding clearly unreliable indicators of growth, the plausible growth rates
9 shown on Exhibits BHF-5, BHF-6, and BHF-7 indicate a range for the LDC group
10 of between approximately 5.50% and 6.75%. Taken together, I conclude that
11 investors expect long-term growth from the LDC group in the 5.5% to 6.5% range.

12 **Q. WHAT CURRENT DCF COST OF EQUITY ESTIMATES DO THESE**
13 **GROWTH RATE RANGES IMPLY FOR THE GAS UTILITY GROUP?**

14 A. Summing the LDC group's average dividend yield of approximately 3.90% with a
15 5.50% to 6.50% growth rate range indicates a current DCF cost of equity for the
16 industry group of between 9.4% and 10.4%.

17 **Q. IS THIS DCF COST OF EQUITY RANGE DIRECTLY APPLICABLE TO**
18 **WTGU?**

19 A. No. The 9.4% to 10.4% DCF cost of equity range developed above is for the group
20 of seven LDCs with publicly traded common stock that, as shown on Exhibit
21 BHF-9, have average Standard & Poor's and Moody's bond ratings, which is
22 generally regarded as the most comprehensive indicator of a firm's risk, of BBB+

1 and single-A, respectively. As noted earlier, WTG Downstream is not rated by the
2 major bond rating agencies, and, if it were, would likely be rated below investment
3 grade or, at best, a low triple-B, which means that it is a more risky investment than
4 the LDC group. Similarly, as will be discussed more completely in the next section
5 on the CAPM, it is well accepted in the financial literature that investors require a
6 higher return from smaller firms than from larger firms, all other things equal. As
7 also shown on Exhibit BHF-9, the average market capitalization (“market cap”) of
8 the firms in the LDC proxy group is some \$6.6 billion. While neither WTGU nor
9 WTG Downstream have a market cap *per se* because they are not publicly traded,
10 one can be estimated based on WTG Downstream’s \$291 million test year-end book
11 equity shown earlier. Specifically, multiplying this book equity times the average
12 market-to-book ratio of the firms in the proxy group of 1.51 times shown in Exhibit
13 BHF-9 implies a market cap of approximately \$440 million. This market cap is
14 only about one-fifteenth of the \$6.6 billion average of the proxy group.
15 Accordingly, to make the LDC industry DCF cost of equity range applicable to
16 WTGU, an adjustment is necessary to account for its greater risk and smaller size
17 relative to the firms in the LDC group.

18 **Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT NECESSARY TO**
19 **ACCOUNT FOR THE GREATER RISK AND SMALLER SIZE OF WTGU**
20 **VERSUS THE LDC INDUSTRY GROUP?**

21 A. Determining the additional return investors require for investing in the common
22 stock of an unrated, smaller utility versus a less risky single-A/triple-B rated, larger
23 utility is complicated by the fact that the cost of equity is unobservable. However,

1 the minimum premium shareholders require for bearing the additional operating
2 and financial risks of a small LDC having only a few dispersed service areas and
3 limited resources versus a multi-state diversified LDC can be gauged by looking at
4 the differences, or spreads, between the yields on below investment grade bonds
5 versus single-A and triple-B rated utility bonds. As shown earlier, the average yield
6 on corporate bonds rated BB in May 2024 was 6.42% versus the yields on single-
7 A and triple-B utility bonds of 5.74% and 5.97%, respectively. Assuming WTG
8 Downstream were a double-B credit, the yield on BB bonds implies that the cost of
9 equity to WTGU for its greater operating and financial risks is between at least 45
10 and 68 basis points (i.e., 6.42% minus 5.97% and 6.42% minus 5.74%,
11 respectively) higher than for the publicly traded LDC proxy group.

12 Meanwhile, Kroll publishes annually a schedule of rate of return premiums
13 to account for differences in the market capitalization of a firm's equity relative to
14 the S&P 500. In the far right columns of the table in the upper portion of Exhibit
15 BHF-9, the market cap of each LDC in the proxy group is displayed along with its
16 corresponding size premium, with the average size premium for the proxy group
17 being 0.93%. From the schedule of size premiums at the bottom of Exhibit BHF-
18 9, the size premium for a firm with a market cap of \$440 million is 1.99%. This
19 implies that the return premium necessary to account for WTG Downstream's
20 smaller size relative to the LDC group is 1.06% (i.e., 1.99% minus the LDCs'
21 0.93%).

1 **Q. WHAT COST OF EQUITY FOR WTGU IS IMPLIED BY YOUR DCF**
 2 **ANALYSIS?**

3 A. Although the 45 to 68 basis point premium for risk differences and the 1.06%
 4 premium for size differences may be theoretically additive, for present purposes, I
 5 have adjusted the DCF cost of equity range for the LDC group by 0.75% to account
 6 for both factors. Adding the 0.75% adjustment for WTGU’s smaller size and
 7 greater risk to the 9.40% to 10.40% DCF cost of equity range for the LDC industry
 8 group produces a DCF cost of equity range for WTGU of 10.15% to 11.15%.

9 **C. Capital Asset Pricing Model**

10 **Q. HOW ELSE DID YOU ESTIMATE THE COST OF EQUITY?**

11 A. The cost of equity to WTGU was also estimated using the CAPM, which is a theory
 12 of market equilibrium that serves as the basis for current financial education and
 13 management. Under the CAPM, investors are assumed fully diversified, so that the
 14 relevant risk of an individual asset (e.g., common stock) is its volatility relative to
 15 the market as a whole, which is measured using a “beta” coefficient. Beta reflects
 16 the tendency of a stock’s price to follow changes in the market, with stocks having
 17 a beta less than 1.00 being considered less risky and stocks with a beta greater than
 18 1.00 being regarded as more risky. The CAPM is mathematically expressed as:

19
$$R_j = R_f + \beta_j (R_m - R_f)$$

20 where: R_j = required rate of return for stock j;
 21 R_f = risk-free interest rate;
 22 R_m = expected return on the market portfolio; and
 23 β_j = beta, or systematic risk, for stock j.

1 While the CAPM is not without controversy, it is routinely referenced in the
2 financial literature and regulatory proceedings, and firms' beta values are widely
3 reported.

4 **Q. HOW DID YOU APPLY THE CAPM?**

5 A. I applied the CAPM using two methods to determine the risk premium for the
6 market as a whole, or the $(R_m - R_f)$ term in the CAPM formula. The first was based
7 on historical rates of return and the second was based on forward-looking estimates
8 of investors' required rates of return. In both instances, the companies included in
9 the S&P 500 index were used as a proxy for the market portfolio and the 30-year
10 U.S. Treasury bond served as the risk-free investment.

11 **Q. PLEASE DESCRIBE THE FIRST METHOD BASED ON HISTORICAL**
12 **RATES OF RETURN.**

13 A. Under the historical rate of return approach, equity risk premiums are calculated by
14 first measuring the rate of return (including dividends and capital gains and losses)
15 actually realized on an investment in common stocks over historical time periods.
16 The historical return on bonds is then subtracted from that earned on common
17 stocks to measure equity risk premiums. Widely used in academia, the historical
18 rate of return approach is based on the assumption that, given a sufficiently large
19 number of observations over long historical periods, average market rates of return
20 will converge to investors' required rates of return. From a more practical
21 perspective, investors may base their expectations for the future on, or may have
22 come to expect that they will earn, rates of return corresponding to those in the past.

1 **Q. WHAT IS THE MARKET RISK PREMIUM BASED ON HISTORICAL**
2 **RATES OF RETURN?**

3 A. Perhaps the most exhaustive study of historical rates of return, and the one most
4 frequently cited in regulatory proceedings, is that contained in *Market Results for*
5 *Stocks, Bonds, Bills and Inflation*, variously published by Ibbotson Associates,
6 Morningstar, Duff & Phelps, and Kroll. The annual rate of return realized on the
7 S&P 500 averaged 12.04% over the period 1926 through 2023 while the annual
8 average income rate of return on 30-year Treasury bonds over this same period
9 averaged 4.87%. Thus, the market risk premium based on historical average annual
10 rates of return is 7.17%, as shown on Exhibit BHF-8.

11 **Q. PLEASE DESCRIBE THE SECOND METHOD BASED ON FORWARD-**
12 **LOOKING REQUIRED RATES OF RETURN.**

13 A. Consistent with the CAPM being an expectational (i.e., forward-looking) model,
14 the second method estimated the market risk premium using current indicators of
15 investors' required rates of return. This method is similar to how the market risk
16 premium is calculated under the *Federal Energy Regulatory Commission's May 21,*
17 *2020 Policy Statement on Determining Return on Equity for Natural Gas and Oil*
18 *Pipelines* ("FERC Policy Statement"). For the market portfolio, the cost of equity
19 was estimated by applying the DCF model to the firms in the S&P 500 paying cash
20 dividends, with each firm's dividend yield and growth rate being weighted by its
21 proportionate share of total market value. The expected dividend yield for each
22 firm was obtained from *Value Line*, with the expected growth rate being based on
23 the earnings forecasts published for each firm by *Value Line*, I/B/E/S, and Zacks.

1 As shown in footnote (b) on Exhibit BHF-8, summing the 1.72% expected dividend
2 yield for this market group, which is composed primarily of non-regulated firms,
3 with the average of the *Value Line*, I/B/E/S, and Zacks projected growth rates of
4 10.05% produces a required rate of return from the market portfolio (R_m) of
5 11.77%.

6 **Q. WHAT IS THE MARKET RISK PREMIUM BASED ON FORWARD-**
7 **LOOKING REQUIRED RATES OF RETURN?**

8 A. From the 11.77% required rate of return on the market portfolio, a market risk
9 premium is calculated by subtracting the average yield on 30-year Treasury bonds
10 during May 2024 of 4.62%. This produces a forward-looking market risk premium
11 of 7.15%.

12 **Q. WHAT IS THE NEXT STEP IN APPLYING THE CAPM?**

13 A. Having calculated market risk premiums of 7.16% and 7.15% using historical rates
14 of return and forward-looking rates of return, respectively, the next step is to
15 calculate specific risk premiums for the LDC industry. This is done by multiplying
16 the alternative market risk premium estimates by the LDC group's average beta of
17 0.88, calculated using firm betas obtained from *Value Line* and shown on Exhibit
18 BHF-8, which produces LDC industry risk premiums of 6.30% and 6.28%.

19 **Q. WHAT ARE THE RESULTING THEORETICAL CAPM COST OF EQUITY**
20 **ESTIMATES FOR THE LDC INDUSTRY?**

21 A. As shown on Exhibit BHF-8, summing the industry risk premiums of 6.30% and
22 6.28% with a risk-free interest rate equal to the May 2024 30-year Treasury bond

1 yield of 4.62% produces current theoretical CAPM cost of equity estimates for
2 LDCs of 10.92% and 10.90%.

3 **Q. ARE THESE THEORETICAL CAPM COST OF EQUITY ESTIMATES**
4 **ACCURATE MEASURES OF INVESTORS' REQUIRED RATE OF**
5 **RETURN FROM WTGU?**

6 A. No. These cost of equity estimates are based on CAPM theory. However, as
7 explained by Morningstar in its *2015 Classic Yearbook* edition of *Stocks, Bonds,*
8 *Bills and Inflation:*

9 One of the most remarkable discoveries of modern finance is that of
10 a relationship between company size and return. Historically on
11 average, small companies have higher returns than those of large
12 ones. . . . The relationship between company size and return cuts
13 across the entire size spectrum; it is not restricted to the smallest
14 stocks. (page 99, footnote omitted)

15 In other words, in addition to the systematic risk measured by beta, investors'
16 required rate of return depends on a firm's relative size. To account for this, Duff &
17 Phelps has developed size premiums that need to be added to the theoretical CAPM
18 cost of equity estimates to account for the level of a firm's market capitalization in
19 determining the CAPM cost of equity.

20 **Q. WHAT ARE THE CURRENT CAPM COST OF EQUITY ESTIMATES FOR**
21 **WTGU ONCE SIZE EFFECTS ARE TAKEN INTO ACCOUNT?**

22 A. As discussed earlier, the premium for firms having a market capitalization of \$440
23 million is 1.99%, which means that the theoretical CAPM cost of equity estimates
24 need to be increased by 1.99% to account for WTG Downstream smaller size
25 relative to the S&P 500. As shown on Exhibit BHF-8, increasing the theoretical
26 CAPM cost of equity estimates by this size premium results in current CAPM cost

1 of equity estimates for WTGU based on historical rates of return and forward-
2 looking rates of return of 12.91% and 12.89%, respectively.

3 **D. Risk Premium Method**

4 **Q. HOW ELSE DID YOU ESTIMATE THE COST OF EQUITY?**

5 A. I also estimated the cost of equity to WTGU using a risk premium method based
6 on ROEs previously authorized for LDCs by state regulatory commissions. The
7 risk premium method to estimate investors' required rate of return is an extension
8 of the risk-return tradeoff observed with bonds to common stocks. The cost of
9 equity is estimated by determining the additional return investors require to forego
10 the relative safety of a bond and bear the greater risks associated with common
11 stock, and then adding this equity risk premium to the current yield on bonds.

12 **Q. GENERALLY, DESCRIBE THE APPLICATION OF THE RISK PREMIUM**
13 **METHOD USING AUTHORIZED ROES.**

14 A. Application of the risk premium method based on authorized ROEs is predicated
15 on the presumption that allowed returns reflect regulatory commissions' best
16 estimates of the cost of equity, however determined, at the time they issued their
17 final orders. A current risk premium is estimated based on the difference between
18 past authorized ROEs and then-prevailing interest rates. This risk premium is then
19 added to current interest rates to estimate the cost of equity. The strength of this
20 approach is that it is based on decades of data reflecting regulatory commissions'
21 evaluation of ROEs for LDCs under various capital market conditions. Because
22 this risk premium method is LDC-specific, it produces cost of equity estimates
23 judged necessary to compensate for the risks of gas distribution and the ROE

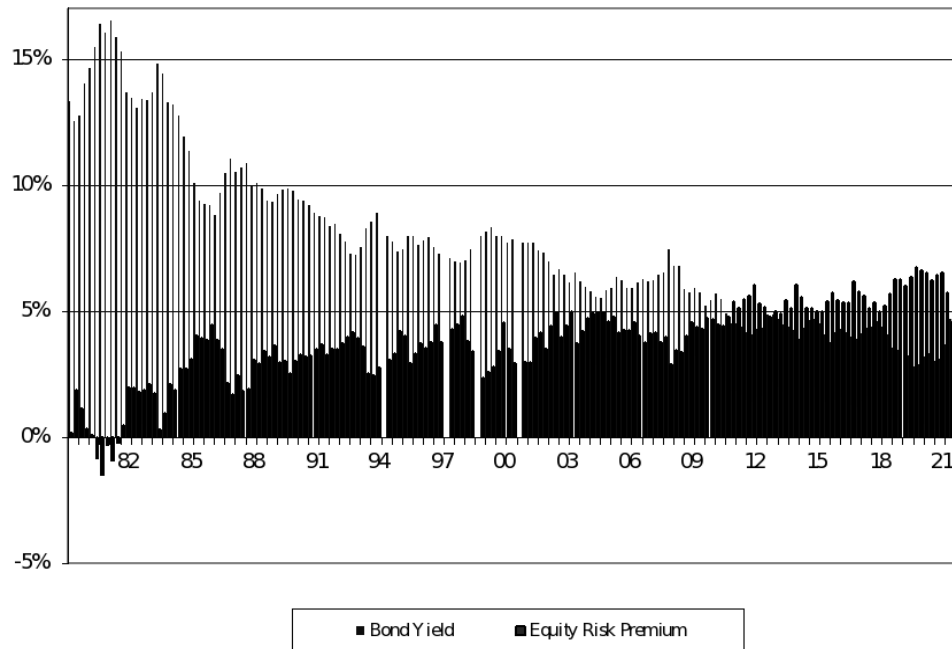
1 required to enable an LDC to attract capital on reasonable terms under current
2 capital market conditions.

3 **Q. WHAT WAS THE PRINCIPAL SOURCE OF THE DATA USED TO APPLY**
4 **THIS RISK PREMIUM METHOD?**

5 A. Regulatory Research Associates, Inc., (“RRA”), which is now a group within S&P
6 Global Market Intelligence, and its predecessors have compiled the ROEs
7 authorized for major electric and gas utilities by regulatory commissions across the
8 U.S. The average ROE authorized for natural gas utilities published by RRA in
9 each quarter between 1980 and 2024 are displayed in Exhibit BHF-10. As shown
10 there, the ROEs granted to LDCs over this approximately 44-year period have
11 averaged 11.36%, while the average utility bond yield has averaged 7.55%,
12 resulting in an average risk premium of 3.81%.

13 **Q. IS THIS 3.81% AVERAGE RISK PREMIUM THE RELEVANT**
14 **BENCHMARK FOR ESTIMATING THE COST OF EQUITY?**

15 A. No. It is necessary to account for the fact that authorized ROEs do not move in
16 lockstep with interest rates. In particular, when interest rate levels are relatively
17 high, ROEs tend to be lower (i.e., equity risk premiums narrow), and when interest
18 rates are relatively low, authorized ROEs are greater (i.e., equity risk premiums
19 increase). This inverse relationship can be observed in the data contained in Exhibit
20 BHF-10, which is shown graphically below. As evident there, the higher the level
21 of interest rates (shaded bars), the lower the equity risk premiums (the solid bars
22 calculated as the difference between authorized ROEs and bond yields), and vice
23 versa:



1 The implication of this inverse relationship is that for a one percent increase or
 2 decrease in interest rates, the cost of equity may only rise or fall, say, one-half of a
 3 percent, respectively.

4 **Q. HOW DID YOU ACCOUNT FOR THE RELATIONSHIP BETWEEN**
 5 **EQUITY RISK PREMIUMS AND INTEREST RATES?**

6 A. To account for the fact that equity risk premiums are lower when interest rates are
 7 high and higher when interest rates are low, I developed two regression equations
 8 relating authorized past equity risk premiums to average utility bond yields. The
 9 first was a simple linear regression between equity risk premiums and interest rates
 10 and the second equation adjusted for first order autocorrelation using the Prais-
 11 Winsten algorithm. Shown in the bottom portion of Exhibit BHF-10, substituting
 12 the May 2024 yield of 5.78% on average utility bonds into the regression equations
 13 indicates that the equity risk premium at current interest rate levels is between
 14 approximately 4.63% and 4.74%

1 **Q. WHAT COST OF EQUITY DOES THIS RISK PREMIUM IMPLY FOR**
2 **WTGU?**

3 A. As discussed earlier, WTG Downstream does not have a credit rating by rating
4 agencies, but if it did, WTG Downstream would likely be rated double-B or, at best,
5 a low triple-B credit. Therefore, I added the 4.63% and 4.74% equity risk premiums
6 developed on Exhibit BHF-10 to the May 2024 yield on triple-B rated utility bonds
7 of 5.97% to calculate a risk premium cost of equity range for WTGU of between
8 10.60% and 10.71%. Using a double-B interest rate of 6.42%, the risk premium
9 cost of equity for WTGU is between 11.05% and 11.16%.

10 **E. Comparable Earnings Method**

11 **Q. WHAT IS THE LAST METHOD THAT YOU USED TO ESTIMATE THE**
12 **COST OF EQUITY?**

13 A. Often referred to as the comparable earnings method, this approach looks to the
14 rates of return that other firms of comparable risk and that compete for investors'
15 capital are expected to earn on their book equity. Reference to the expected return
16 on book equity of other LDCs demonstrates the level of earnings that is needed in
17 order to offer investors a competitive return, be able to attract capital on reasonable
18 terms, and maintain its financial integrity.

19 **Q. WHAT RETURNS ON BOOK EQUITY ARE OTHER LDCS EXPECTED**
20 **TO EARN?**

21 A. Exhibit BHF-11 displays the return on book equity projected for each of the seven
22 LDCs in the industry group for the 2024, 2025, and the 2027-2029 timeframes,
23 calculated by dividing *Value Line's* projected earnings per share by average book
24 value per share. As shown there, the average expected book ROE for the group is

1 8.90% in 2024, 9.20% for 2025, and 9.90% for 2027-2029, with medians of 8.4%,
2 8.4%, and 9.9%, respectively. Again, adjusting these industry numbers upwards by
3 75 basis points to reflect the smaller size and greater risk of WTGU relative to the
4 proxy group results in comparable earnings values of between 9.15% and 10.65%.

5 **F. Rate of Return on Equity Range**

6 **Q. WHAT IS YOUR CONCLUSION AS TO THE CURRENT COST OF**
7 **EQUITY RANGE FOR WTGU?**

8 A. The DCF method indicates a cost of equity range for WTGU of between
9 approximately 10.15% and 11.15%, while the CAPM indicates a cost of equity
10 range of approximately 12.9%. Meanwhile, the risk premium method based on the
11 authorized ROEs for LDCs and applicable interest rates indicates a cost of equity
12 of between approximately 10.6% and 11.2%, and the comparable earnings method
13 implies a fair rate of return on book equity of between approximately 9.2% and
14 10.7%. Taken together, my analyses indicate that investors currently require a ROE
15 from WTGU in the range of 10.75% to 11.75%.

16 **Q. WHAT ROE DO YOU RECOMMEND BE USED TO CALCULATE**
17 **WTGU'S RATE OF RETURN?**

18 A. Although my quantitative analyses indicate a cost of equity to WTGU in the range
19 of 10.75% to 11.75%, as discussed earlier, WTGU is not requesting an increase to
20 cost-based rates. For purposes of determining the cost of providing service and in
21 GRIP filings, I recommend that an ROE from the bottom of my range, or 10.75%,
22 be used.

1 **Q. HAVE YOU CONDUCTED ANY CHECKS OF REASONABLENESS OF**
 2 **YOUR RECOMMENDED ROE FOR WTGU?**

3 A. Yes. The reasonableness of my recommended 10.75% ROE for WTGU can be
 4 evaluated by reviewing the ROEs previously granted by the Commission. The table
 5 below lists the ROEs authorized for the three largest LDCs in Texas from 2016
 6 through the present:

Date	Docket	Utility	ROEs
8/25/2015	10432	CP Entex – TX Coast	10.00%
5/3/2016	10488	TGS – Gulf Coast	9.50%
9/27/2016	10506	TGS – West Texas	9.50%
11/15/2016	10526	TGS – Central Texas	9.50%
5/23/2017	10567	CP Entex -- Houston	9.60%
12/5/2017	10640	Atmos -- Dallas	10.10%
3/20/2018	10656	TGS -- RGV	9.50%
5/22/2018	10669	CP Entex – S. Texas	9.80%
11/13/2018	10739	TGS -- NTSA	9.75%
12/11/2018	10742	Atmos – Mid-Tex	9.80%
12/11/2018	10743	Atmos – West Texas	9.75%
2/5/2019	10766	TGS -- BSSA	9.75%
5/21/2019	10779	Atmos – Mid-Tex	9.80%
4/21/2020	10900	Atmos-West Texas	9.80%
4/21/2020	10920	CP Entex-	9.65%
8/4/2020	10928	TGS-CGSA	9.50%
1/18/2023	00009896	TGS-WNSA	9.60%
1/30/2024	00014399	TGS-RGVSA	9.70%
6/25/2024	00015513	CenterPoint Energy	9.80%

7 Since 2016, the ROEs authorized Atmos, CenterPoint, and TGS have ranged
 8 between 9.5% and 10.1%. However, this historical range must be adjusted upwards
 9 to account for current interest rates on utility bonds being approximately 5.8%
 10 versus an average of 4.2% over the 2016-2023 timeframe, and for WTGU’s greater

1 risk and smaller size relative to Atmos, CenterPoint, and TGS. Once these
2 adjustments are made, WTGU's requested 10.75% ROE is fully supported by the
3 Commission's past ROE decisions.

4 **VII. OVERALL RATE OF RETURN**

5 **Q. WHAT OVERALL RATE OF RETURN DO YOU RECOMMEND BE USED**
6 **TO DETERMINE WTGU'S COST OF PROVIDING SERVICE AND IN**
7 **GRIP FILINGS?**

8 A. I recommend an overall rate of return for present purposes of 8.10%. As developed
9 in Exhibit BHF-1 (and in Schedule E of WTGU's Rate Filing Schedules), this rate
10 of return is the result of combining capital structure ratios of 34.40% debt and
11 65.60% equity with a cost of debt of 3.06% and an ROE of 10.75%.

12 **Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?**

13 A. Yes, it does.

APPENDIX A

BRUCE H. FAIRCHILD

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

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Austin, Texas 78751
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Summary of Qualifications

M.B.A. and Ph.D. in finance, accounting, and economics; Certified Public Accountant. Extensive consulting experience involving regulated industries, valuation of closely-held businesses, and other economic analyses. Previously held managerial and technical positions in government, academia, and business, and taught at the undergraduate, graduate, and executive education levels. Broad experience in technical research, computer modeling, and expert witness testimony.

Employment

Principal,
FINCAP, Inc.
(Sep. 1979 to present)

Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included revenue requirements, rate of return, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Other assignments have involved some seventy valuations as well as various economic (e.g., damage) analyses, typically in connection with litigation. Presented expert witness testimony before courts and regulatory agencies on over one hundred occasions.

Adjunct Assistant Professor, University
of Texas at Austin
(Sep. 1979 to May. 1981)

Taught undergraduate courses in finance: Fin. 370 – Integrative Finance and Fin. 357 – Managerial Finance.

*Assistant Director, Economic Research
Division,*
Public Utility Commission of Texas
(Sep. 1976 to Aug. 1979)

Division consisted of approximately twenty-five financial analysts, economists, and systems analysts responsible for rate of return, rate design, special projects, and computer systems. Directed Staff participation in rate cases, presented testimony on approximately thirty-five occasions, and was involved in some forty other cases ultimately settled. Instrumental in the initial development of rate of return and financial policy for newly-created agency. Performed independent research and managed State and Federal funded projects. Assisted in preparing appeals to the Texas Supreme Court and testimony presented before the Interstate Commerce Commission and Department of Energy. Maintained communications with financial community, industry representatives, media, and consumer groups. Appointed by Commissioners as Acting Director.

BRUCE H. FAIRCHILD

Assistant Professor, College of Business Administration,
University of Colorado at Boulder
(Jan. 1977 to Dec. 1978)

Taught graduate and undergraduate courses in finance: Fin. 305 – Introductory Finance, Fin. 401 – Managerial Finance, Fin. 402 – Case Problems in Finance, and Fin. 602 – Graduate Corporate Finance.

Teaching Assistant,
University of Texas at Austin
(Jan. 1973 to Dec. 1976)

Taught undergraduate courses in finance and accounting: Acc. 311 – Financial Accounting, Acc. 312 – Managerial Accounting, and Fin. 357 – Managerial Finance. Elected to College of Business Administration Teaching Assistants' Committee.

Internal Auditor,
Sears, Roebuck and Company, Dallas,
Texas
(Nov. 1970 to Aug 1972)

Performed audits on internal operations involving cash, accounts receivable, merchandise, accounting, and operational controls, purchasing, payroll, etc. Developed operating and administrative policy and instruction. Performed special assignments on inventory irregularities and Justice Department Civil Investigative Demands.

Accounts Payable Clerk,
Transcontinental Gas Pipeline Corp.,
Houston, Texas
(May. 1969 to Aug. 1969)

Processed documentation and authorized payments to suppliers and creditors.

Education

Ph.D., Finance, Accounting, and Economics,
University of Texas at Austin
(Sep. 1974 to May 1980)

Doctoral program included coursework in corporate finance, investment theory, accounting, and economics. Elected to honor society of Phi Kappa Phi. Received University outstanding doctoral dissertation award.

Dissertation: *Estimating the Cost of Equity to Texas Public Utility Companies*

M.B.A., Finance and Accounting,
University of Texas at Austin,
(Sep. 1972 to Aug. 1974)

Awarded Wright Patman Scholarship by World and Texas Credit Union Leagues.

Professional Report: *Planning a Small Business Enterprise in Austin, Texas*

B.B.A., Accounting and Finance,
Southern Methodist University, Dallas,
Texas
(Sep. 1967 to Dec. 1971)

Dean's List 1967-1971 and member of Phi Gamma Delta Fraternity.

Other Professional Activities

Certified Public Accountant, Texas Certificate No. 13,710 (October 1974); entire exam passed in May 1972. Member of the American Institute of Certified Public Accountants (Honorary).

Participated as session chairman, moderator, and paper discussant at annual meetings of Financial Management Association, Southwestern Finance Association, American Finance Association, and other professional associations.

Visiting lecturer in Executive M.B.A program at the University of Stellenbosch Graduate Business School, Belleville, South Africa (1983 and 1984).

Associate Editor of *Austin Financial Digest*, 1974-1975. Wrote and edited a series of investment and economic articles published in a local investment advisory service.

BRUCE H. FAIRCHILD

Military

Texas Army National Guard, Feb. 1970 to Sep. 1976. Specialist 5th Class with duty assignments including recovery vehicle operator for armor unit and company clerk for finance unit.

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- “Energy Conservation in Existing Residences, Project Director for development of instruction manual and workshops promoting retrofitting of existing homes, *Governor's Office of Energy Resources and Department of Energy* (1977-1978).
- “Linear Algebra,” “Calculus,” “Sets and Functions,” and “Simulation Techniques,” contributed to and edited four mathematics programmed learning texts for MBA students, *Texas Bureau of Business Research* (1975).

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BRUCE H. FAIRCHILD

- “Perspectives on Texas Utility Regulation”, TSCPA 2016 Energy Conference, Austin, Texas (May 16, 2016).
- “Legislative Changes Affecting Texas Utilities,” Texas Committee of Utility and Railroad Tax Representatives, Fall Meeting, Austin, Texas (September 1995).
- “Rate of Return,” “Origins of Information,” “Economics,” and “Deferred Taxes and ITC’s,” New Mexico State University and National Association of Regulatory Utility Commissioners Public Utility Conferences on Regulation and the Rate-Making Process, Albuquerque, New Mexico (October 1983, 1984, 1985, 1986, 1987, 1988, 1990, 1991, 1992, 1994, and 1995, and September 1989); Pittsburgh, Pennsylvania (April 1993); and Baltimore, Maryland (May 1994 and 1995).
- “Developing a Cost-of-Service Study,” 1994 Texas Section American Water Works Association Annual Conference, Amarillo, Texas (March 1994).
- “Financial Aspects of Cost of Capital and Common Cost Considerations,” Kidder, Peabody & Co. Two-Day Rate Case Workshop for Regulated Utility Companies, New York, New York (June 1993).
- “Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).
- “Rate Base and Revenue Requirements,” The University of Texas Regulatory Institute Fundamentals of Utility Regulation, Austin, Texas (June 1989 and 1990).
- “Determining the Cost of Capital in Today's Diversified Companies,” New Mexico State University Public Utilities Course Part II, Advanced Analysis of Pricing and Utility Revenues, San Francisco, California (June 1990).
- “Estimating the Cost of Equity,” Oklahoma Association of Tax Representatives, Tulsa, Oklahoma (May 1990).
- “Impact of Regulations,” Business and the Economy, Leadership Dallas, Dallas, Texas (November 1989).
- “Accounting and Finance Workshop” and “Divisional Cost of Capital,” New Mexico State University Current Issues Challenging the Regulatory Process, Albuquerque, New Mexico (April 1985 and 1986) and Santa Fe, New Mexico (March 1989).
- “Divisional Cost of Equity by Risk Comparability and DCF Analyses,” NARUC Advanced Regulatory Studies Program, Williamsburg, Virginia (February 1988) and USTA Rate of Return Task Force, Chicago, Illinois (June 1988).
- “Revenue Requirements,” Revenue, Pricing, and Regulation in Texas Water Utilities, Texas Water Utilities Conference, Austin, Texas (August 1987 and May 1988).
- “Rate Filing – Basic Ratemaking,” Texas Gas Association Accounting Workshop, Austin, Texas (March 1988).
- “The Effects of Regulation on Fair Market Value: P.H. Robinson – A Case Study,” Annual Meeting of the Texas Committee of Utility and Railroad Tax Representatives, Austin, Texas (September 1987).
- “How to Value Closely-held Businesses,” TSCPA 1987 Entrepreneurs Conference, San Antonio, Texas (May 1987).
- “Revenue Requirements” and “Determining the Rate of Return”, New Mexico State University Regulation and the Rate-Making Process, Southwestern Water Utilities Conference, Albuquerque, New Mexico (July 1986) and El Paso, Texas (November 1980).
- “How to Evaluate Personal Service Practices,” TSCPA CPE Exposition 1985, Houston and Dallas, Texas (December 1985).
- “How to Start a Small Business – Accounting and Record Keeping,” University of Texas Management Development Program, Austin, Texas (October 1984).
- “Project Financing of Public Utility Facilities”, TSCPA Conference on Public Utilities Accounting and Ratemaking, San Antonio, Texas (April 1984).
- “Valuation of Closely-Held Businesses,” Concho Valley Estate Planning Council, San Angelo, Texas (September 1982).

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- “Rating Regulatory Performance and Its Impact on the Cost of Capital,” New Mexico State University Seminar on Regulation and the Cost of Capital, El Paso, Texas (May 1982).
- “Effect of Inflation on Rate of Return,” Cost of Capital Conference and Workshop, Pinehurst, North Carolina (April 1981).
- “Original Cost Versus Current Cost Regulation: A Re-examination,” Financial Management Association, New Orleans, Louisiana (October 1980).
- “Capital Investment Analysis for Electric Utilities,” The University of Texas at Dallas, Richardson, Texas (June 1980).
- “The Determinants of Capital Costs to the Electric Utility Industry,” with Cedric E. Grice, Southwestern Finance Association, San Antonio, Texas (March 1980).
- “The Entrepreneur and Management: A Case Study,” Small Business Administration Seminar, Austin, Texas (October 1979).
- “Capital Budgeting by Public Utilities: A New Perspective,” with W. Clifford Atherton, Jr., Financial Management Association, Boston, Massachusetts (October 1979).
- “Issues in Regulated Industries – Electric Utilities,” University of Texas at Dallas 4th Annual Public Utilities Conference, Dallas, Texas (July 1979).
- “Investment Conditions and Strategies in Today's Markets,” American Society of Women Accountants, Austin, Texas (January 1979).
- “Attrition: A Practical Problem in Determining a Fair Return to Public Utility Companies,” Financial Management Association, Minneapolis, Minnesota (October 1978).
- “The Cost of Equity to Wholly-Owned Electric Utility Subsidiaries,” with William L. Beedles, Financial Management Association, Minneapolis, Minnesota (October 1978).
- “PUC Retrofitting Program,” Texas Electric Cooperatives Spring Workshop, Austin, Texas (May 1978).
- “The Economics of Regulated Industries,” Consumer Economics Forum, Houston, Texas (November 1977).
- “Public Utilities as Consumer Targets – Is the Pressure Justified?” University of Texas at Dallas 2nd Annual Public Utilities Conference, Dallas, Texas (July 1977).

APPENDIX B

BRUCE H. FAIRCHILD
SUMMARY OF TESTIMONY BEFORE REGULATORY AGENCIES

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
1.	Arkansas Electric Cooperative	Arkansas PSC	U-3071	Aug-80	Wholesale Rate Design
2.	East Central Oklahoma Electric Cooperative	Oklahoma CC	26925	Sep-80	Retail Rate Design
3.	Kansas Gas & Electric Company	Kansas CC	115379-U	Nov-80	PURPA Rate Design Standards
4.	Kansas Gas & Electric Company	Kansas CC	128139-U	May-81	Attrition
5.	City of Austin Electric Department	City of Austin	--	Jun-81	PURPA Rate Design Standards
6.	Tarrant County Water Control and Improvement District No. 1	Texas Water Commission	--	Oct-81	Wholesale Rate Design
7.	Owentown Gas Company	Texas RRC	2720	Jan-82	Revenue Requirements and Retail Rate Design
8.	Kansas Gas & Electric Company	Kansas CC	134792-U	Aug-82	Attrition
9.	Mississippi Power Company	Mississippi PSC	U-4190	Sep-82	Working Capital
10.	Lone Star Gas Company	Texas RRC	3757; 3794	Feb-83	Rate of Return on Equity
11.	Kansas Gas & Electric Company	Kansas CC	134792-U	Feb-83	Rate of Return on Equity
12.	Southwestern Bell Telephone Company	Oklahoma CC	28002	Oct-83	Rate of Return on Equity
13.	Morgas Company	Texas RRC	4063	Nov-83	Revenue Requirements
14.	Seagull Energy	Texas RRC	4541	Jul-84	Rate of Return
15.	Southwestern Bell Telephone Company	FCC	84-800	Nov-84	Rate of Return on Equity
16.	Kansas Gas & Electric Company, Kansas City Power & Light Company, and Kansas Electric Power Cooperatives	Kansas CC	142098-U; 142099-U; 142100-U	May-85	Nuclear Plant Capital Costs and Allowance for Funds Used During Construction
17.	Lone Star Gas Company	Texas RRC	5207	Oct-85	Overhead Cost Allocation
18.	Westar Transmission Company	Texas RRC	5787	Nov-85 Jan-86 Jul-86	Rate of Return, Rate Design, and Gas Processing Plant Economics
19.	City of Houston	Texas Water Commission	RC-022; RC-023	Nov-86	Line Losses and Known and Measurable Changes
20.	ENSTAR Natural Company	Alaska PUC	TA 50-4; R-87-2; U-87-2	Nov-86 May-87 May-87	Cost Allocation, Rate Design, and Tax Rate Changes
21.	Brazos River Authority	Texas Water Commission	RC-020	Jan-87	Revenue Requirements and Rate Design
22.	East Texas Industrial Gas Company	Texas RRC	5878	Feb-87	Revenue Requirements and Rate Design

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
23.	Seagull Energy	Texas RRC	6629	Jun-87	Revenue Requirements
24.	ENSTAR Natural Company	Alaska PUC	U-87-42	Jul-87 Sep-87 Sep-87	Cost Allocation, Rate Design, and Contracts
25.	High Plains Natural Gas Company	Texas RRC	6779	Sep-87	Rate of Return
26.	Hughes Texas Petroleum	Texas RRC	2-91,855	Jan-88	Interim Rates
27.	Cavallo Pipeline Company	Texas RRC	7086	Sep-88	Revenue Requirements
28.	Union Gas System, Inc.	Kansas CC	165591-U	Mar-89 Aug-89	Rate of Return
29.	ENSTAR Natural Gas Company	Alaska PUC	U-88-70	Mar-89	Cost Allocation and Bypass
30.	Morgas Co.	Texas RRC	7538	Aug-89	Rate of Return and Cost Allocation
31.	Corpus Christi Transmission Company	Texas RRC	7346	Sep-89	Revenue Requirements
32.	Amoco Gas Co.	Texas RRC	7550	Oct-89	Rate of Return and Cost Allocation
33.	Iowa Southern Utilities	Iowa Utilities Board	RPU-89-7	Nov-89 Mar-90	Rate of Return on Equity
34.	Southwestern Bell Telephone Company	FCC	89-624	Feb-90 Apr-90	Rate of Return on Equity
35.	Lower Colorado River Authority	Texas PUC	9427	Mar-90 Aug-90 Aug-90	Revenue Requirements
36.	Rio Grande Valley Gas Company	Texas RRC	7604	May-90	Consolidated FIT and Depreciation
37.	Southern Union Gas Company	El Paso PURB	--	Oct-90	Disallowed Expenses and FIT
38.	Iowa Southern Utilities	Iowa Utilities Board	RPU-90-8	Nov-90 Feb-91	Rate of Return on Equity
39.	East Texas Gas Systems	Texas RRC	7863	Dec-90	Revenue Requirements
40.	San Jacinto Gas Transmission	Texas RRC	7865	Dec-90	Revenue Requirements
41.	Southern Union Gas Company	Austin; Texas RRC	-- 7878	Feb-91 Feb-91	Rate of Return and Acquisition Adjustment
42.	Southern Union Gas Company	Port Arthur; Texas RRC	-- 8033	Mar-91 Aug-91 Oct-91	Rate of Return and Acquisition Adjustment
43.	Cavallo Pipeline Company	Texas RRC	8016	Jun-91	Revenue Requirements

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
44.	New Orleans Public Service Inc.	New Orleans City Council	CD-91-1	Jun-91 Mar-92	Rate of Return on Equity
45.	Houston Pipe Line Company	Texas RRC	8017	Jul-91	Rate of Return
46.	Southern Union Gas Company	El Paso PURB	--	Aug-91 Sep-91	Acquisition Adjustment
47.	Southwestern Gas Pipeline, Inc.	Texas RRC	8040	Jan-92 Feb-92	Rate Design and Settlement
48.	City of Fort Worth	Texas Water Commission	8748-A 9261-A	Mar-92 Aug-92 Dec-92 Oct-94 Nov-94	Interim Rates, Revenue Requirements, and Public Interest
49.	Southern Union Gas Company	Oklahoma Corp. Com.	--	Jun-92	Rate of Return
50.	Minnegasco	Minnesota PUC	G-008/GR-92-400	Jul-92 Dec-92	Rate of Return
51.	Guadalupe-Blanco River Authority	Texas PUC	11266	Sep-92	Cost Allocation and Bond Funds
52.	Dorchester Intra-State Gas System	Texas RRC	8111	Oct-92 Nov-92	Rate Impact of System Upgrade
53.	Corpus Christi Transmission Company GP and GPII	Texas RRC	8300 8301	Oct-92 Oct-92	Revenue Requirements
54.	East Texas Industrial Gas Company	Texas RRC	8326	Mar-93	Revenue Requirements
55.	Arkansas Louisiana Gas Company	Arkansas PSC	93-081-U	Apr-93 Oct-93	Rate of Return on Equity
56.	Texas Utilities Electric Company	Texas PUC	11735	Jun-93 Jul-93	Impact of Nuclear Plant Construction Delay
57.	Minnegasco	Minnesota PUC	G-008/GR-93-1090	Nov-93 Apr-94	Rate of Return
58.	Gulf States Utilities Company	Municipalities	--	May-94 Oct-94 Nov-94	Rate of Return on Equity
59.	Louisiana Power & Light Company	Louisiana PSC	U-20925	Aug-94 Feb-95	Rate of Return on Equity
60.	San Jacinto Gas Transmission	Texas RRC	8429	Sep-94	Revenue Requirements
61.	Cavallo Pipeline Company	Texas RRC	8465	Sep-94	Revenue Requirements
62.	Eastrans Limited Partnership	Texas RRC	8385	Oct-94	Revenue Requirements
63.	Gulf States Utilities Company	Louisiana PSC	U-19904	Oct-94	Rate of Return on Equity

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
64.	Entergy Services, Inc.	FERC	ER95-112-000	Mar-95 Nov-95	Rate of Return on Equity
65.	East Texas Gas Systems	Texas RRC	8435	Apr-95	Revenue Requirements
66.	System Energy Resources, Inc.	FERC	ER95-1042-000	May-95 Dec-95 Jan-96	Rate of Return on Equity
67.	Minnegasco	Minnesota PUC	G-008/GR-95-700	Aug-95 Dec-95	Rate of Return
68.	Entex	Louisiana PSC	U-21586	Aug-95	Rate of Return
69.	City of Fort Worth	Texas NRCC	SOAH 582-95-1084	Nov-95	Public Interest of Contract
70.	Seagull Energy Corporation	Texas RRC	8589	Nov-95	Revenue Requirements
71.	Corpus Christi Transmission Company LP	Texas RRC	8449	Feb-96	Revenue Requirements
72.	Missouri Gas Energy	Missouri PSC	GR-96-285	Apr-96 Sep-96 Oct-96	Rate of Return
73.	Entex	Mississippi PSC	96-UA-202	May-96	Rate of Return
74.	Entergy Gulf States, Inc.	Louisiana PSC	U-22084	May-96	Rate of Return on Equity (Gas)
75.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-96 Oct-96	Rate of Return on Equity
76.	American Gas Storage, L.P.	Texas RRC	8591	Sep-96	Revenue Requirements
77.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	Sep-96 Oct-96	Rate of Return on Equity
78.	Lone Star Pipeline and Gas Company	Texas RRC	8664	Oct-96 Jan-97	Rate of Return
79.	Entergy Arkansas, Inc.	Arkansas PSC	96-360-U	Oct-96 Sep-97	Rate of Return on Equity
80.	East Texas Gas Systems	Texas RRC	8658	Nov-96	Revenue Requirements
81.	Entergy Gulf States, Inc.	Texas PUC	16705	Nov-96 Jul-97	Rate of Return on Equity
82.	Eastrans Limited Partnership	Texas RRC	8657	Nov-96	Revenue Requirements
83.	Enserch Processing, Inc.	Texas RRC	8763	Nov-96	Interim Rates
84.	Entergy New Orleans, Inc.	City of New Orleans	UD-97-1	Feb-97 Mar-97 May-98	Rate of Return on Equity

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
85.	ENSTAR Natural Gas Company	Alaska PUC	U-96-108	Mar-97 Apr-97	Service Area Certificate
86.	San Jacinto Gas Transmission	Texas RRC	8741	Sep-97	Revenue Requirements
87.	Missouri Gas Energy	Missouri PSC	GR-98-140	Nov-97 Apr-98 May-98	Rate of Return
88.	Corpus Christi Transmission Company LP	Texas RRC	8762	Dec-97	Revenue Requirements
89.	Texas-New Mexico Power Company	Texas PUC	17751	Feb-98	Excess Cost Over Market
90.	Southern Union Gas Company	Texas RRC	8878	May-98	Rate of Return
91.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	May-98 Jul-98	Financial Integrity
92.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-98 Jul-98	Financial Integrity
93.	ACGC Gathering Company, LLC	Texas RRC	8896	Sep-98	Cost-based Rates
94.	American Gas Storage, L.P.	Texas RRC	8855	Oct-98	Revenue Requirements
95.	Duke Energy Intrastate Network	Texas RRC	8940	Jun-99	Rate of Return
96.	Aquila Energy Corporation	Texas RRC	8970	Aug-99	Revenue Requirements
97.	San Jacinto Gas Transmission	Texas RRC	8974	Sep-99	Revenue Requirements
98.	Southern Union Gas Company	El Paso PURB	--	Oct-99	Rate of Return
99.	TXU Lone Star Pipeline	Texas RRC	8976	Oct-99 Feb-00	Rate of Return
100.	Sharyland Utilities, L.P.	Texas PUC	21591	Nov-99	Rate of Return
101.	TXU Lone Star Gas Distribution	Texas RRC	9145	Apr-00 Aug-00	Rate of Return
102.	Rotherwood Eastex Gas Storage	Texas RRC	9136	May-00	Revenue Requirements
103.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9137	May-00	Revenue Requirements
104.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9138	Jul-00	Revenue Requirements
105.	East Texas Gas Systems	Texas RRC	9139	Jul-00	Revenue Requirements
106.	Eastrans Limited Partnership	Texas RRC	9140	Aug-00	Revenue Requirements
107.	Reliant Energy – Entex	City of Tyler	--	Oct-00	Rate of Return
108.	City of Fort Worth	Texas NRCC	SOAH 582-00-1092	Dec-00	CCN – Rates and Financial Ability
109.	Entergy Services, Inc.	FERC	RTO1-75	Dec-00	Rate of Return on Equity

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
110	ENSTAR Natural Gas Company	Alaska PUC	U-00-88	Jun-01 Aug-01 Nov-01 Sep-02 Dec-02	Revenue Requirements, Cost Allocation, and Rate Design
111.	TXU Gas Distribution	Texas RRC	9225	Jul-01	Rate of Return
112.	Centana Intrastate Pipeline LLC	Texas RRC	9243	Aug-01	Rate of Return
113.	Maxwell Water Supply Corp.	Texas NRCC	SOAH-582-01-0802	Oct-01 Mar-02 Apr-02	Reasonableness of Rates
114.	Reliant Energy Arkla	Arkansas PSC	01-243-U	Dec-01 Jun-01	Rate of Return
115.	Entergy Services, Inc.	FERC	ER01-2214-000	Mar-02	Rate of Return on Equity
116.	TXU Lone Star Pipeline	Texas RRC	9292	Apr-02	Rate of Return
117.	Southern Union Gas Company	El Paso PURB	--	Apr-02	Rate of Return
118.	San Jacinto Gas Transmission Co.	Texas RRC	9301	May-02	Rate of Return
119.	Duke Energy Intrastate Network	Texas RRC	9302	May-02	Rate of Return
120.	Reliant Energy Arkla	Oklahoma CC	200200166	May-02	Rate of Return
121.	TXU Gas Distribution	Texas RRC	9313	Jul-02 Sep-02	Rate of Return
122.	Entergy Mississippi, Inc.	Mississippi PSC	2002-UN-256	Aug-02	Rate of Return on Equity
123.	Aquila Storage & Transportation LP	Texas RRC	9323	Sep-02	Revenue Requirements
124.	Panther Pipeline Ltd.	Texas RRC	9291	Oct-02	Revenue Requirements
125.	SEMCO Energy	Michigan PSC	U-13575	Nov-02	Revenue Requirements
126.	CenterPoint Energy Entex	Louisiana PSC	U-26720	Jan-03	Rate of Return
127.	Crosstex CCNG Transmission Ltd.	Texas RRC	9363	May-03	Revenue Requirements
128.	TXU Gas Company	Texas RRC	9400	May-03 Jan-04	Rate of Return
129.	Eastrans Limited Partnership	Texas RRC	9386	May-03	Rate of Return
130.	CenterPoint Energy Entex	City of Houston		Jun-03	Rate of Return
131.	East Texas Gas Systems, L.P.	Texas RRC	9385	Jun-03	Rate of Return
132.	ENSTAR Natural Gas Company	Alaska RCA	U-03-084	Aug-03 Nov-03	Line Extension Surcharge
133.	CenterPoint Energy Arkla	Louisiana PSC		Nov-03	Rate of Return
134.	ENSTAR Natural Gas Company	Alaska RCA	U-03-091	Feb-04	Cost Separation and Taxes

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
135.	Sid Richardson Pipeline, Ltd.	Texas RRC	9532	Jun-04 Nov-04	Revenue Requirements
136.	ETC Katy Pipeline, Ltd.	Texas RRC	9524	Sep-04	Revenue Requirements
137.	CenterPoint Energy Entex	Mississippi PSC	03-UN-0831	Sep-04	Rate Formula
138.	Centana Intrastate Pipeline LLC	Texas RRC	9527	Sep-04	Rate of Return
139.	SEMCO Energy	Michigan PSC	U-14338	Dec-04	Revenue Requirements
140.	Atmos Energy – Energas	Texas RRC	9539	Feb-05	Regulatory Policy
141.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9613	Sep-05	Revenue Requirements
142.	SiEnergy, L.P.	Texas RRC	9604	Dec-05	Rate of Return, Income Taxes, and Cost Allocation
143.	ENSTAR Natural Gas Company	Alaska RCA	TA-140-4	Feb-06	Connection Fees
144.	SEMCO Energy	Michigan PSC	U-14984	May-06 Dec-06	Revenue Requirements
145.	Atmos Energy – Mid-Tex	Texas RRC	9676	May-06 Oct-06	Revenue Requirements
146.	EasTrans Limited Partnership	Texas RRC	9659	Jun-06	Rate of Return
147.	Kinder Morgan Texas Pipeline, L.P.	Texas RRC	9688	Jul-06	Rate of Return
148.	Crosstex CCNG Transmission Ltd.	Texas RRC	9660	Aug-06	Revenue Requirements
149.	Enbridge Pipelines (North Texas), LP	Texas RRC	9691	Oct-06	Rate of Return
150.	Panther Interstate Pipeline Energy	FERC	CP03-338-00	Mar-07	Revenue Requirements
151.	El Paso Electric Company	Texas PUC	34494	Jul-07	CCN
152.	El Paso Electric Company	NM PRC	07-00301-UT	Jul-07	CCN
153.	Atmos Energy	Kansas CC	08-ATMG- 280-RTS	Sep-07 Feb-08	Rate of Return on Equity
154.	Centana Intrastate Pipeline LLC	Texas RRC	9759	Sep-07	Rate of Return
155.	Texas Gas Service Company	Texas RRC	9770	Nov-07	Rate of Return
156.	ENSTAR Natural Gas Company	Alaska RCA	U-08-25	Jun-08	Rate Class Switching
157.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-131-301	Oct-08	Rate of Return
158.	ExxonMobil Pipeline Co.	Alaska RCA	TL-140-304	Nov-08	Rate of Return
159.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9843	Dec-08	Revenue Requirements
160.	Koch Alaska Pipeline Company	Alaska RCA	TL 128-308	Dec-08	Rate of Return
161.	Unocal Pipeline Company	Alaska RCA	TL 118-312	Dec-08	Rate of Return

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
162.	ETC Katy Pipeline, Ltd.	Texas RRC	9841	Dec-08	Revenue Requirements
163.	Oklahoma Natural Gas	Oklahoma CC	200800348	Jan-09	Rate of Return on Equity
164.	Entergy Mississippi, Inc.	Mississippi PSC	EC-123-0082	Mar 09	Rate of Return on Equity
165.	ENSTAR Natural Gas Company	Alaska RCA	U-09-69 U-09-70	Jun-09 Jul-09 Oct-09	Revenue Requirements, Cost Allocation, and Rate Design
166.	EasTrans, LLC	Texas RRC	9857	Jun-09	Rate of Return
167.	Oklahoma Natural Gas	Oklahoma CC	200900110	Jun-09	Rate of Return
168.	Crosstex CCNG Transmission Ltd.	Texas RRC	9858	Jun-09	Revenue Requirements
169.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul-09	Rate of Return
170.	ENSTAR Natural Gas Company	Alaska RCA	U-08-142	Jul-09	Gas Cost Adjustment
171.	Kinder Morgan Texas Pipeline, LLC	Texas RRC	9889	Jul-09	Rate of Return
172.	Koch Alaska Pipeline Company	Alaska RCA	TL 133-308	Aug-09	Rate of Return
173.	ExxonMobil Pipeline Co.	Alaska RCA	TL-147-304	Nov-09	Rate of Return
174.	Texas Gas Service Company	El Paso PURB	--	Dec-09	Rate of Return
175.	Unocal Pipeline Company	Alaska RCA	TL126-312	Dec-09	Rate of Return
176.	Kuparuk Transportation Company	Alaska RCA	P-08-05	Apr-10	Rate of Return
177.	Trans-Alaska Pipeline System	FERC	ISO9-348- 000	Apr 10 Oct 10	Rate of Return
178.	Texas Gas Service	Texas RRC	9988	May 10 Aug 10	Rate of Return
179.	SEMCO Energy Gas Company	Michigan PSC	U-16169	Jun 10 Dec 10	Revenue Requirements
180.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul 10	Rate of Return
181.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-308	Aug 10	Rate of Return
182.	CPS Energy	Texas PUC	36633	Sep 10 Apr 11	Rate of Return for MOU
183.	ExxonMobil Pipeline Co.	Alaska RCA	TL-151-304	Dec 10	Rate of Return
184.	Unocal Pipeline Company	Alaska RCA	TL132-312	Feb 11	Rate of Return
185.	New Mexico Gas Company	NM PRC	11-00042-UT	Mar 11	Rate of Return
186.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-143-301	May 11	Rate of Return

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
187.	Enbridge Pipelines (Southern Lights)	FERC	IS11-146-000	Jun 11 Nov 11	Rate of Return
188.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-___	Jul 11	Rate of Return
189.	Unocal Pipeline Company	Alaska RCA	TL126-___	Dec 11	Rate of Return
190.	Kansas Gas Service	Kansas CC	12-KGSC-835-RTS	May 12 Oct 12	Rate of Return
191.	ExxonMobil Pipeline Co.	Alaska RCA	TL-157-304	Jun 12	Rate of Return
192.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-149-301	Jul 12	Rate of Return
193.	Seaway Crude Pipeline Company	FERC	IS12-226-000	Aug 12 Feb 13	Rate of Return
194.	Cross Texas Transmission, LLC	Texas PUC	40604	Aug 12 Oct 12 Nov 12	Revenue Requirements
195.	Wind Energy Transmission Texas	Texas PUC	40606	Aug 12 Nov 12	Revenue Requirements
196.	Lone Star Transmission LLC	Texas PUC	40798	Nov 12	Revenue Requirements
197.	West Texas Gas Company	Texas RRC	10235	Jan 13	Rate of Return
198.	Cross Texas Transmission, LLC	Texas PUC	41190	Feb 13	Revenue Requirements
199.	ExxonMobil Pipeline Co.	Alaska RCA	TL-162-304	Apr 13	Rate of Return
200.	EasTrans,LLC	Texas RRC	10276	Jul 13	Rate of Return
201.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-152-301	Jul 13	Rate of Return
202.	BP Pipelines (Alaska) Inc.	Alaska RCA	TL-143-311	Sep 13	Rate of Return
203.	Wind Energy Transmission Texas	Texas PUC	41923	Oct 13	Revenue Requirements
204.	Oliktok Pipeline Company	Alaska RCA	P-13-013	Nov 13	Rate of Return
205.	Aqua Texas Southeast Region-Gray	Texas CEQ	2013-2007-UCR	Apr 14	Revenue Requirements
206.	Entergy Mississippi	Mississippi PSC	EC-123-0082	Jun 14	Rate of Return on Equity
207.	Westlake Ethylene Pipeline	Texas RRC	10358	Jul 14 Aug 15	Rates
208.	ExxonMobil Pipeline Co.	Alaska RCA	TL-164-304	Jul 14	Rate of Return
209.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-154-301	Aug 14	Rate of Return
210.	ENSTAR Natural Gas Company	Alaska RCA	TA-262-4	Sep 14 Jun 15	Revenue Requirements, Cost Allocation, and Rate Design

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
211.	Oliktok Pipeline Company	Alaska RCA	TL-44-334	Mar 15	Rate of Return
212.	Entergy Arkansas, Inc.	Arkansas PSC	15-0150U	Apr 15 Oct 15 Dec 15	Rate of Return on Equity
213.	Wind Energy Transmission Texas	Texas PUC	44746	Jun 15	Revenue Requirements
214.	Texas City	Texas RRC	10408	Jun 15 Nov 15	Pipeline Annual Assessment
215.	Oklahoma Natural Gas	Oklahoma CC	201500213	Jul 15 Nov 15	Rate of Return
216.	PTE Pipeline LLC	Alaska RCA	P-12-015	Sep 15	Rate of Return
217.	Northeast Transmission Development, LLC	FERC	ER16-453	Dec 15	Formula Rates
218.	Oncor Electric Delivery	Texas PUC	45188	Dec 15	Public Interest of Acquisition
219.	Corix Utilities (Texas)	Texas PUC	45418	Dec 15 Oct 16	Rate of Return
220.	Texas Gas Service	Texas RRC	10488	Dec 15	Rate of Return
221.	Texas Gas Service	Texas RRC	10506	Mar 16 Jun 16	Rate of Return
222.	Kansas Gas Service	Kansas CC	16-KGSG-491-RTS	May 16 Sep 16	Rate of Return on Equity
223.	ENSTAR Natural Gas Company	Alaska RCA	TA-285-4	Jun 16 Apr 17	Revenue Requirements, Cost Allocation, and Rate Design
224.	Texas Gas Service	Texas RRC	10526	Jun 16	Rate of Return
225.	West Texas LPG Pipeline	Texas RRC	10455	Aug 16 Jan 17	Rates and Rate of Return
226.	Liberty Utilities	Texas PUC	46356	Sep 16 Feb 17 Jun 17	Revenue Requirements and Rate of Return
227.	DesertLink LLC	FERC	ER17-135	Oct 16	Formula Rates
228.	Houston Pipe Line Co.	Texas RRC	10559	Nov 16	Revenue Requirements
229.	Texas Gas Service	Texas RRC	10656	Jun 17	Rate of Return
230.	Trans-Pecos Pipeline	Texas RRC	10646	Sep 17 Feb 18	Revenue Requirements
231.	Comanche Trail Pipeline	Texas RRC	10647	Sep 17 Feb 18	Revenue Requirements
232.	Alpine High Pipeline	Texas RRC	10665	Oct 17 Feb 18	Revenue Requirements

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
233.	SiEnergy, LP	Texas RRC	10679	Jan 18	Rate of Return
234.	Targa Midland Gas Pipeline LLC	Texas RRC	10690	Jan 18	Revenue Requirements
235.	ET Fuel, LP	Texas RRC	10706	Apr 18	Revenue Requirements
236.	Texas Gas Service	Texas RRC	10739	Jun 18	Rate of Return
237.	Kansas Gas Service	Kansas CC	18-KGSG-560-RTS	Jun 18 Nov 18	Rate of Return on Equity
238.	Oliktok Pipeline Company	Alaska RCA	TL46-334	Jul 18	Rate of Return
239.	Red Bluff Express, LLC	Texas RRC	10752	Jul 18	Revenue Requirements
240.	PTE Pipeline LLC	Alaska RCA	P-18-0__	Jul 18	Rate of Return
241.	Agua Blanca, LLC	Texas RRC	10761	Aug 18	Revenue Requirements
242.	Texas Gas Service	Texas RRC	10766	Aug 18	Rate of Return
243.	Republic Transmission LLC	FERC	ER19-__	Dec 18	Formula Rates
244.	Gulf Coast Express Pipeline LLC	Texas RRC	10825	Feb 19	Revenue Requirements
245.	Cook Inlet Natural Gas Storage Alaska, LLC	Alaska RCA	U-18-043	Mar 19 Apr 19	Accumulated Deferred Income Taxes and Working Capital
246.	Impulsora Pipeline LLC	Texas RRC	10829	Mar 19	Revenue Requirements
247.	SEMCO Energy Gas Co.	Michigan PSC	U-20479	May 19 Oct 19	Revenue Requirements
248.	Liberty Utilities (Fox River) LLC	AAA	01-18-0002-2510	Jul 19 Oct 19	Revenue Requirements
249.	AMP Intrastate Pipeline LLC	Texas RRC	10887	Aug 19	Revenue Requirements
250.	Corix Utilities (Texas) Inc.	Texas PUC	49923	Aug 19 Jul 20 Aug 20	TCJA Tax Expense Reduction
251.	Colonial Pipeline Company	FERC	OR18-7-003	Nov 19 Feb 20 May 20 Jul 20	Rate of Return
252.	Texas Gas Service	Texas RRC	10928	Dec 19 Apr 20	Rate of Return
253.	Mississippi Power Company	Mississippi PSC	2019-UN-219	Feb 20	Rate of Return on Equity
254.	Corix Utilities (Texas)	Texas PUC	50557	Mar 20 Mar 21	Rate of Return and Excess ADFIT
255.	SouthCross CCNG Transmission	Texas RRC	10967	May 20	Revenue Requirements
256.	Kinder Morgan Border Pipeline LLC	Texas RRC	10980	Jun 20	Revenue Requirements

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

257. Monarch Utilities I LP	Texas PUC	50944	Jul 20 Nov 20	Rate of Return
258. West Texas Gas, Inc.	Texas RRC	10998	Aug 20	Revenue Requirements, Rate of Return, and Cost of Service Study
259. Centric Gas Services, LLC	Texas RRC		Oct 20	Rate of Return
260. CoServ Gas, Ltd	Texas RRC	00005136	Nov 20	Rate of Return
261. Permian Highway Pipeline LLC	Texas RRC	00005306	Dec 20	Revenue Requirements
262. Whistler Pipeline LLC	Texas RRC	00005675	Feb 21	Revenue Requirements
263. Oklahoma Natural Gas	Oklahoma CC	202100063	May 21 Oct 21	Rate of Return
264. Oliktok Pipeline Company	Alaska RCA	TL47-334	Jul 21	Rate of Return
265. Participating Gas Utilities	Texas RRC	00007061	Jul 21 Oct 21	Excess Gas Cost Securitization
266. Texas Pipeline Webb County Lean System, LLC	Texas RRC	00008188	Nov 21	Revenue Requirements
267. Legend Gas Pipeline LLC	Texas RRC	00008714	Jan 22	Revenue Requirements
268. Oliktok Pipeline Company	Alaska RCA	TL48-334	Mar 22	Rate of Return
269. Texas Gas Service	Texas RRC	00009896	Jun 22 Oct 22	Rate of Return
270. ENSTAR Natural Gas Company	Alaska RCA	U-22-081	Aug 22 Jul 23	Income Taxes, Cost Allocation, and Rate Design
271. Acacia Natural Gas, L.L.C.	Texas RRC	00010150	Aug 22	Revenue Requirements
272. Corix Utilities (Texas)	Texas PUC	53815	Aug 22 Sep 23	Rate of Return, Cost Allocation, and Rate Design
273. Oliktok Pipeline Company	Alaska RCA	TL50-334/51-334	Jan 23	Rate of Return
274. Delaware-Permian Pipeline LLC	Texas RRC	00013058	Mar 23	Revenue Requirements
275. SiEnergy LLC	Texas RRC	00013504	Mar 23	Rate of Return
276. Texas Gas Service	Texas RRC	00014399	Jun 23	Rate of Return
277. CoServ Gas, Ltd	Texas RRC	00014771	Jul 23	Rate of Return
278. Matterhorn Express Pipeline, LLC	Texas RRC	00014719	Aug 23	Revenue Requirements
279. TPL SouthTex Transmission Co. LP	Texas RRC	00015056	Aug 23	Revenue Requirements
280. Kansas Gas Service	Kansas CC	24-KGSG-610-RTS	Mar 24	Rate of Return on Equity
281. Delaware Link Ventures, LLC	Texas RRC	000124190	Mar 24	Revenue Requirements
276. Texas Gas Service	Texas RRC	00017471	Jun 24	Rate of Return

STATE OF TEXAS §
 §
COUNTY OF TRAVIS §

AFFIDAVIT OF BRUCE H. FAIRCHILD

BEFORE ME, the undersigned authority, on this day personally appeared Bruce H. Fairchild, who having been placed under oath by me did depose as follows:

- 1. “My name is Bruce H. Fairchild. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is principal in Financial Concepts and Applications, Inc.
- 2. I have prepared the foregoing direct testimony and the information contained in this document is true and correct to the best of my knowledge.”

Further affiant sayeth not.

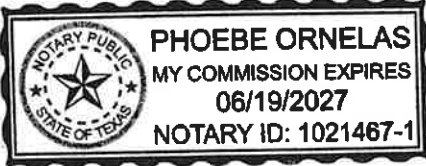


 Bruce H. Fairchild

SUBSCRIBED AND SWORN TO BEFORE ME by the said Bruce H. Fairchild on this 8th day of July 2024.



 Notary Public, State of Texas



**WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN**

**Exhibit BHF-1
Page 1 of 1**

OVERALL RATE OF RETURN

<u>Capital Component</u>	<u>Percent of Total</u>	<u>Component Cost</u>	<u>Weighted Cost</u>
Long-term Debt	34.40%	3.06%	1.05%
Common Equity	65.60%	10.75%	7.05%
Total	<u>100.00%</u>		<u>8.10%</u>

WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN

Exhibit BHF-2
Page 1 of 1

CAPITAL STRUCTURE

WTG DOWNSTREAM HOLDINGS LLC (a)

	December 31, 2023	
	Amount	Percent of Total
Debt	\$ 152,670,914	34.40%
Equity	291,132,606	65.60%
Total	\$ 443,803,520	100.00%

LDC PROXY GROUP (b)

Company	2023		2022		2021		2020	
	Debt	Equity	Debt	Equity	Debt	Equity	Debt	Equity
Atmos Energy	37.9%	62.1%	37.9%	62.1%	38.4%	61.6%	40.0%	60.0%
Chesapeake Utilities	48.8%	51.2%	41.0%	59.0%	41.5%	58.5%	42.2%	57.8%
New Jersey Resources	58.2%	41.8%	57.8%	42.2%	57.0%	43.0%	55.1%	44.9%
NiSource	52.2%	47.8%	55.7%	44.3%	56.9%	43.1%	61.6%	38.4%
Northwest Natural Gas	52.6%	47.4%	51.5%	48.5%	52.8%	47.2%	49.2%	50.8%
ONE Gas	43.8%	56.2%	50.7%	49.3%	61.1%	38.9%	41.5%	58.5%
Spire	54.9%	45.1%	51.2%	48.8%	52.5%	47.5%	49.0%	51.0%
LDC GROUP AVERAGE	49.8%	50.2%	49.4%	50.6%	51.5%	48.5%	48.4%	51.6%
Minimum	37.9%	41.8%	37.9%	42.2%	38.4%	38.9%	40.0%	38.4%
Maximum	58.2%	62.1%	57.8%	62.1%	61.1%	61.6%	61.6%	60.0%

(a) WTG Downstream Holdings LLL Audit Report (December 31, 2023).

(b) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).

	AGA									
	2022		2021		2020		2019		2018	
Common Equity	79,789	57.2%	73,052	56.4%	71,398	57.7%	66,682	58.1%	58,007	58.0%
Preferred Stock	24	0.0%	25	0.0%	25	0.0%	1,105	1.0%	62	0.1%
Long-term Debt	59,675	42.8%	56,413	43.6%	52,377	42.3%	47,058	41.0%	41,904	41.9%
	139,488	100.0%	129,490	100.0%	123,800	100.0%	114,845	100.0%	99,973	100.0%

**WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN**

**Exhibit BHF-3
Page 1 of 1**

COST OF DEBT

WTG DOWNSTREAM HOLDINGS LLC (a)

<u>Description</u>	<u>Amount</u>	<u>Interest Rate</u>	<u>Annual Interest</u>
Senior A Notes due 9/15/2026	\$ 55,000,000	2.36%	\$ 1,298,000
Senior B Notes due 9/15/2028	55,000,000	2.72%	1,496,000
Senior C Notes due 9/15/2028	45,000,000	2.99%	1,345,500
Debt Issuance Costs	(2,329,086)		538,746
Total	\$ 152,670,914		\$ 4,678,246
Cost of Debt		<u><u>3.06%</u></u>	

LDC PROXY GROUP (b)

<u>Company</u>	<u>Cost of Debt</u>
Atmos Energy	3.95%
Chesapeake Utilities	4.95%
New Jersey Resources	3.76%
NiSource	3.77%
Northwest Natural Gas	4.82%
ONE Gas	3.63%
Spire	4.14%
Average Cost of Debt	<u><u>4.14%</u></u>

(a) WTG Downstream Holdings LLL Audit Report (December 31, 2023).

(b) 2023 Form 10-Ks.

**WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN**

**Exhibit BHF-4
Page 1 of 1**

DCF MODEL -- DIVIDEND YIELD

<u>Company</u>	<u>Ticker</u>	<u>Expected Dividend (a)</u>	<u>Price (b)</u>	<u>Dividend Yield (c)</u>
Atmos Energy	ATO	\$ 3.40	\$ 117.06	2.90%
Chesapeake Utilities	CPK	\$ 2.60	\$ 110.38	2.36%
New Jersey Resources	NJR	\$ 1.70	\$ 43.83	3.88%
NiSource	NI	\$ 1.08	\$ 28.66	3.77%
Northwest Natural Gas	NWN	\$ 1.95	\$ 37.85	5.15%
ONE Gas	OGS	\$ 2.66	\$ 63.14	4.21%
Spire	SR	\$ 3.09	\$ 61.44	5.03%
AVERAGE				3.90%
MEDIAN				3.88%

(a) *The Value Line Investment Survey* "Summary & Index" (May 31, 2024).

(b) *Yahoo!* Finance (average of daily closing prices during May 2024).

(c) Expected Dividend / Price.

WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN

Exhibit BHF-5
Page 1 of 1

DCF MODEL -- EARNINGS GROWTH RATES

Company	Projected Growth			Historical Growth	
	Value	I/B/E/S	Zacks (d)	10-Year (a)	5-Year (a)
	Line (a)	LSEG (b)			
Atmos Energy	7.0%	7.4%	7.0%	9.5%	9.0%
Chesapeake Utilities	6.5%	7.6%	N/R	9.0%	10.0%
New Jersey Resources	5.0%	N/R	N/R	5.0%	2.5%
NiSource	9.5%	7.4%	6.0%	1.5%	15.0%
Northwest Natural Gas	6.5%	N/R	N/R	-1.0%	2.5%
ONE Gas	3.5%	N/R	5.0%	N/R	6.0%
Spire	4.5%	6.4%	5.0%	5.0%	3.0%
AVERAGE	6.1%	7.2%	5.8%	4.8%	6.9%
MEDIAN	6.5%	7.4%	5.5%	5.0%	6.0%

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).

(b) LSEG Stock Reports Plus (May 30, 2024).

(d) Zacks.com "Snapshot" (Retrieved May 31, 2024).

N/R -- None reported.

WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN

Exhibit BHF-6
Page 1 of 1

DCF MODEL -- SUSTAINABLE GROWTH RATES

Company	2027-2029 Projected (a)					Shares Outstanding (a)		Earnings Retention Growth			External Financing Growth				Sustainable Growth	
	Ticke	Earnings per Share	Dividends per Share	Book Value per Share	Price per Share	2023	Proj. 27-29	Retention Ratio	Return on Equity	"b x r"	2027-2029 Market-to-Book Ratio	Growth Rate in Shares	"s"	"v"		"s x v"
Atmos Energy	\$	8.35	\$ 4.25	\$ 83.50	\$ 137.50	148.49	175.00	49.1%	10.0%	4.9%	1.65	3.3%	5.5%	39.3%	2.2%	7.1%
Chesapeake Utilities	\$	7.00	\$ 3.25	\$ 70.70	\$ 140.00	22.24	25.00	53.6%	9.9%	5.3%	1.98	2.4%	4.7%	49.5%	2.3%	7.6%
New Jersey Resources	\$	3.50	\$ 1.95	\$ 27.00	\$ 60.00	97.57	100.00	44.3%	13.0%	5.7%	2.22	0.5%	1.1%	55.0%	0.6%	6.3%
NiSource	\$	2.20	\$ 1.20	\$ 20.40	\$ 42.50	446.38	450.00	45.5%	10.8%	4.9%	2.08	0.2%	0.3%	52.0%	0.2%	5.1%
Northwest Natural Gas	\$	3.20	\$ 1.98	\$ 36.10	\$ 62.50	37.63	45.00	38.1%	8.9%	3.4%	1.73	3.6%	6.3%	42.2%	2.7%	6.0%
ONE Gas	\$	5.00	\$ 2.85	\$ 60.20	\$ 90.00	56.55	57.00	43.0%	8.3%	3.6%	1.50	0.2%	0.2%	33.1%	0.1%	3.6%
Spire	\$	5.50	\$ 3.60	\$ 66.05	\$ 87.50	53.20	62.00	34.5%	8.3%	2.9%	1.32	3.1%	4.1%	24.5%	1.0%	3.9%
AVERAGE										4.4%					1.3%	5.7%
MEDIAN										4.9%					1.0%	6.0%

(a) The Value Line Investment Survey "Ratings & Reports" (May 24, 2024).

WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN

Exhibit BHF-7
Page 1 of 1

DCF MODEL -- OTHER PROJECTED AND HISTORICAL GROWTH RATES

Company	Net Book Value (a)			Dividends per Share (a)			Price per Share		
	Pro- jected	Historical		Pro- jected	Historical		Pro- jected (a)	Historical (b)	
		10-Year	5-Year		10-Year	5-Year		10-Year	5-Year
Atmos Energy	4.0%	9.5%	12.0%	7.5%	7.0%	8.5%	4.1%	8.8%	2.8%
Chesapeake Utilities	6.5%	10.5%	10.5%	8.0%	8.0%	10.0%	6.1%	10.0%	3.5%
New Jersey Resources	4.5%	7.5%	7.0%	5.0%	6.5%	6.5%	8.2%	5.5%	-2.3%
NiSource	5.0%	-3.0%	0.5%	4.5%	-0.5%	3.5%	10.4%	7.1%	0.5%
Northwest Natural Gas	4.0%	1.0%	0.5%	0.5%	1.5%	0.5%	13.4%	-1.5%	-11.2%
ONE Gas	4.5%	N/R	4.5%	2.5%	N/R	8.5%	9.3%	N/R	-6.4%
Spire	5.5%	5.5%	3.5%	4.5%	5.0%	5.5%	9.2%	2.9%	-6.2%
AVERAGE	4.9%	5.2%	5.5%	4.6%	4.6%	6.1%	8.7%	5.4%	-2.8%
MEDIAN	4.5%	6.5%	4.5%	4.5%	5.8%	6.5%	9.2%	6.3%	-2.3%

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).

(b) *Yahoo! Finance* (Average May 2014 and 2019 closing prices to average May 2024 closing price).

N/R -- None reported.

**WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN**

**Exhibit BHF-8
Page 1 of 1**

CAPITAL ASSET PRICING MODEL

Description	Historical Rates of Return (a)	Forward-Looking Rates of Return (b)
Market Required Rate of Return	12.04%	11.77%
Long-term Government Bond Return (a)(c)	4.87%	4.62%
Market Risk Premium (d)	7.17%	7.15%
LDC Group Beta (e)	0.88	0.88
LDC Group Risk Premium (f)	6.30%	6.28%
Risk-free Rate of Interest (c)	4.62%	4.62%
Theoretical CAPM Cost of Equity Estimate (g)	10.92%	10.90%
Size Premium (e)	1.99%	1.99%
CAPM Cost of Equity Estimates (h)	12.91%	12.89%

(a) *Kroll Cost of Capital Navigator.*

(b) Calculated by applying DCF model applied to S&P 500 firms paying dividends (May 21, 2024):

Expected Dividend Yield	1.72%
Projected Earnings Growth Rate:	
Value Line	9.24%
I/B/E/S	10.23%
Zacks	10.67%
Average	10.05%
Market Required Rate of Return	11.77%

(c) May 2024 yield on 30-year U.S. Treasury bonds (Federal Reserve). 4.62%

(d) Market Required Rate of Return minus Long-term Government Bond Return.

(e) Schedule BHF-9.

(f) Market risk premium times beta.

(g) Sum of Risk Premium and Risk-free Rate of Interest.

(h) Sum of Theoretical CAPM Cost of Equity Estimate and Size Premium.

WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN

Exhibit BHF-9
Page 1 of 1

BOND RATINGS, BETA, MARKET CAPITALIZATION, AND SIZE PREMIUMS

Risk Measures

Company	Bond Rating		Beta (c)	Market-to Book Ratio	Market Capitalization (c)	
	S&P (a)	Moody's (b)			(millions)	Premium(d)
Atmos Energy	A-	A1	0.85	1.60	\$ 17,600	0.46%
Chesapeake Utilities	N/R	N/R	0.80	1.97	\$ 2,500	1.21%
New Jersey Resources	N/R	A1	1.00	2.15	\$ 4,400	0.95%
NiSource	BBB+	Baa2	0.95	1.26	\$ 12,900	0.61%
Northwest Natural Gas	A+	Baa1	0.85	1.11	\$ 1,500	1.39%
ONE Gas	A-	A3	0.85	1.29	\$ 3,600	0.95%
Spire	BBB+	Baa2	0.85	1.22	\$ 3,600	0.95%
	BBB+	A3	0.88	1.51	\$ 6,586	0.93%

LDC GROUP AVERAGE

CRSP Deciles Size Premiums (e)

Decile	Market Capitalization of Smallest Company (in millions)	Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
1-Largest	\$ 36,942.976	\$ 2,662,326.048	-0.06%
2	14,910.719	36,391.113	0.46%
3	7,493.607	14,820.048	0.61%
4	4,622.261	7,461.284	0.64%
5	3,011.224	4,621.785	0.95%
6	1,864.293	3,010.806	1.21%
7	1,050.083	1,862.491	1.39%
8	555.880	1,046.037	1.14%
9	213.039	554.523	1.99%
10- Smallest	1.576	212.644	4.70%

(a) Moody's.com (Retrieved June 5, 2024).

(b) StandardandPoors.com (Retrieved June 5, 2024).

(c) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).

(d) Kroll Cost of Capital Navigator (Retrieved February 19, 2024).

**WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN**

**Exhibit BHF-11
Page 1 of 1**

COMPARABLE EARNINGS METHOD

Company	Projected Earned Return on Book Equity (a)		
	2024	2025	2027-29
Atmos Energy	9.1%	9.4%	10.0%
Chesapeake Utilities	8.8%	8.8%	9.9%
New Jersey Resources	13.8%	13.1%	13.0%
NiSource	7.4%	8.2%	10.8%
Northwest Natural Gas	7.1%	8.2%	8.9%
ONE Gas	8.1%	8.1%	8.3%
Spire	8.4%	8.4%	8.3%
LDC GROUP AVERAGE	<u>8.9%</u>	<u>9.2%</u>	<u>9.9%</u>
MEDIAN	<u>8.4%</u>	<u>8.4%</u>	<u>9.9%</u>

(a) *The Value Line Investment Survey "Ratings & Reports"* (May 24, 2024).

WORKPAPERS
TO
DIRECT TESTIMONY
OF
BRUCE H. FAIRCHILD

Workpapers to the Direct Testimony of Bruce H. Fairchild are voluminous and are being provided in electronic format.

**PUBLIC NOTICE OF PROPOSED RATE CHANGE
 NATURAL GAS UTILITY RATES**

On July 16, 2024, West Texas Gas Utility, LLC (“WTGU” or the “Company”), filed a Statement of Intent to increase its gas utility rates with the Railroad Commission of Texas (“Commission”) for the unincorporated areas within Andrews, Archer, Armstrong, Atascosa, Bailey, Bastrop, Bexar, Brewster, Briscoe, Brown, Caldwell, Carson, Castro, Cochran, Coleman, Collingsworth, Concho, Crosby, Culberson, Dallam, Dawson, Deaf Smith, Dimmit, Donley, Floyd, Frio, Gaines, Gray, Hale, Hall, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Jeff Davis, Kimble, Kinney, La Salle, Lamb, Lipscomb, Lubbock, Lynn, McCulloch, Martin, Mason, Maverick, Medina, Menard, Moore, Ochiltree, Oldham, Parmer, Pecos, Potter, Presidio, Randall, Reeves, Roberts, Runnels, Sherman, Sutton, Swisher, Terry, Tom Green, Travis, Uvalde, Val Verde, Wheeler, Wilson, Winkler, Yoakum, and Zavala Counties and with the Cities of Amarillo, Balmorhea, Cactus, Canadian, Canyon, Claude, Dalhart, Darrouzett, Devine, Eden, Farwell, Follett, Groom, Higgins, Junction, Kermit, La Vernia, Lockhart, Lubbock, Luling, Menard, Miami, Mobeetie, Natalia, Paint Rock, Seguin, Shamrock, Somerset, Sonora, Stratford, Texhoma, Texline, Van Horn, Wheeler, White Deer, and Wolfforth, Texas (“Cities”) for those incorporated areas. The proposed change in rates will affect all customers within the incorporated and unincorporated areas WTGU serves in the state of Texas that take service through WTGU’s tariffed rates that are approved by a regulator. The proposed effective date of the requested change is August 20, 2024.

If approved, the proposed rates and tariffs are expected to increase the Company’s jurisdictional annual revenue for the areas served by WTGU by \$6,778,890 or approximately 35.75% including gas costs or 51.4% excluding gas cost. The proposed change in rates constitutes a “major change” as that term is defined in Section 104.101 of the Texas Utilities Code because the proposed changes will increase the total aggregate revenues of the Company by more than two and one-half percent. The proposed change in rates will not become effective until similar changes have become effective within the nearest incorporated city.

The Company proposes to implement the rates included in Table 1:

TABLE 1 – Proposed Rate Changes for Incorporated and Environs Customers

Customer Class	Number of Customers	Current Customer Charge***	Proposed Customer Charge	Current Volumetric Charge (Mcf)	Proposed Volumetric Charge (Mcf)
Domestic*	17,923	\$23.42	\$29.50	\$4.84	\$7.68
Non-Domestic**	2,485	\$43.57	\$79.00	\$2.69	\$4.89

*A Domestic customer typically refers to residential service.

**A Non-domestic customer does not receive service under the residential tariff and includes commercial, industrial customers, public authority customers, and non-profit customers.

*** Includes interim rate adjustment increase that is scheduled to go into effect on August 30, 2024.

TABLE 2 – Impact on Average Bill for Incorporated and Environs Customers

Customer Class and Gas Cost Zone (Average Monthly Usage Mcf)	Current Average Monthly Bill with Gas Cost	Proposed Average Monthly Bill with Gas Cost	Proposed Monthly Increase	Percentage Increase with Gas Cost	Percentage Change without Gas Cost
North Zone					
Domestic	\$73.96	\$96.83	\$22.87	30.9%	44.0%
Non-Domestic	\$164.10	\$240.97	\$76.86	46.8%	81.6%
West Zone					
Domestic	\$60.83	\$80.67	\$19.84	32.6%	42.3%
Non-Domestic	\$179.22	\$268.22	\$89.01	49.7%	81.6%
South Zone					
Domestic	\$42.50	\$55.33	\$12.83	30.2%	36.7%
Non-Domestic	\$184.46	\$272.60	\$88.14	47.8%	81.6%

Avg Monthly Usage Mcf for the North gas cost zone is as follows: Domestic, 5.91 Mcf; Non-Domestic, 18.83 Mcf.

Avg Monthly Usage Mcf for the West gas cost zone is as follows: Domestic, 4.85 Mcf; Non-Domestic, 24.35 Mcf.

Avg Monthly Usage Mcf for the South gas cost zone is as follows: Domestic, 2.38 Mcf; Non-Domestic, 23.96 Mcf.

The amounts in Table 2 rely on the average cost of gas for 2023 in each gas zone as follows: North Zone, \$3.71 per Mcf; West Zone, \$2.88 per Mcf; and South Zone, \$3.19 per Mcf.

The North Zone includes Unincorporated areas within the Counties of Armstrong, Carson, Collingsworth, Dallam, Deaf Smith, Donley, Gray, Hall, Hansford, Hartley, Hemphill, Hutchinson, Lipscomb, Moore, Ochiltree, Oldham, Potter, Randall, Roberts, Sherman, and Wheeler, and within the Cities of Amarillo, Cactus, Canadian, Canyon, Claude, Dalhart, Darrrouzett, Farwell, Follett, Groom, Higgins, Miami, Mobeetie, Shamrock, Stratford, Texhoma, Texline, Wheeler, and White Deer.

The South Zone includes Unincorporated areas within the Counties of Atascosa, Bastrop, Bexar, Brown, Caldwell, Coleman, Concho, Dimmit, Frio, Kimble, Kinney, La Salle, Mason, Maverick, McCulloch, Medina, Menard, Runnels, Sutton, Tom Green, Travis, Uvalde, Val Verde, Wilson, and Zavala, and within the Cities of Devine, Eden, Junction, La Vernia, Lockhart, Luling, Menard, Natalia, Paint Rock, Seguin, Somerset, and Sonora.

The West Zone includes Unincorporated areas within the Counties of Andrews, Archer, Bailey, Brewster, Briscoe, Castro, Cochran, Crosby, Culberson, Dawson, Floyd, Gaines, Hale, Hockley, Jeff Davis, Lamb, Lubbock, Lynn, Martin, Parmer, Pecos, Presidio, Reeves, Swisher, Terry, Winkler, and Yoakum, and within the Cities of Balmorhea, Kermit, Lubbock, Van Horn, and Wolfforth.

In addition to the proposed rate changes for the Company's domestic and non-domestic customers, other proposed tariff changes include the addition of a new Winter Storm Cost Recovery Rider, removal of the EDIT Credit Rider, non-substantive changes to the Pipeline Safety Fee Rider, and other minor formatting changes.

The Company is also requesting Commission approval of new depreciation rates; a prudence determination for capital investment the Company has made through December 31, 2023; approval of a 51.22% allocation factor for capital investment costs that should be allocated to or recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers to be used in future interim rate adjustment (“IRA”) filings; the approval of regulatory asset amounts comprised of costs related to Winter Storm Uri; recovery of the Winter Storm Uri regulatory asset through a monthly surcharge over 60 months; and approval to recover the reasonable rate case expenses associated with this filing through a surcharge on rates, as provided by law. The exact amount of rate case expenses and the surcharge amount will not be known until the case is complete.

Persons with specific questions or desiring additional information about this filing may contact West Texas Gas Utility, LLC at (432) 682-4349. Complete copies of the filed Statement of Intent, including all proposed rates, schedules and tariffs are available for inspection at WTGU’s offices located at 303 Veterans Airpark Ln, Suite 5000, Midland, Texas 79705 and on our website at <https://www.westtexasgas.com/texas-rate-case/>. In addition, any affected person within the environs may file written comments or a protest concerning the proposed rate change with the Docket Services Section of the Office of the Hearings Division, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, at any time within 30 days following the date on which the change would or has become effective, or September 19, 2024. Please reference Case No. OS-24-00017816. Any affected person within an incorporated area may contact his or her city council.

Este aviso tiene como fin informarles a los clientes de la División de West Texas Gas Utility, LLC que la Compañía ha presentado una solicitud para aumentar las tarifas del servicio público de gas. Esta solicitud afecta a todos los clientes domésticos y no domésticos en las áreas servidas por West Texas Gas Utility, LLC. Las personas que deseen hacer preguntas específicas o recibir más información sobre esta solicitud pueden comunicarse con la Compañía llamando al (432) 682-4349. Cualquier persona afectada puede presentar por escrito comentarios o una protesta sobre el cambio de tarifas propuesto a Docket Services Section, Office of the Hearings Division, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, en cualquier momento dentro de los 30 días siguientes a la fecha en que este cambio entraría en vigencia. Por favor haga referencia a Case No. OS-24-00017816. Cualquier persona afectada dentro de un área incorporada puede contactar a su Consejo Municipal.

**WEST TEXAS GAS UTILITY, LLC,
STATEMENT OF INTENT TO INCREASE GAS UTILITY RATES WITHIN
THE UNINCORPORATED AREAS OF TEXAS
PROTECTIVE AGREEMENT**

This Protective Agreement shall govern the use of all information deemed confidential or highly sensitive confidential information by a party responding to discovery requests, filing testimony, or otherwise providing information during the above-referenced municipal statement of intent proceeding, including information whose confidentiality may be under dispute in this matter.

1. Designation of Protected Materials

Any party or person producing or filing a document, including, but not limited to, records stored or encoded on a computer disk or other similar electronic storage medium, in this proceeding may designate that document, or any portion of it, as confidential by typing or stamping on its face **“PROTECTED MATERIALS PROVIDED PURSUANT TO PROTECTIVE AGREEMENT”** (hereinafter referred to as “protected materials”). The documents shall be consecutively Bates Stamped when necessary.

2. Materials Excluded from Protected Materials Designation

Protected materials shall not include any information or document contained in the public files of the Railroad Commission of Texas, or any other federal or state agency, court, or local government authority subject to the Public Information Act or under the Federal Freedom of Information Act provided however, that any party or person may assert any privilege or exception available under these Acts. Protected materials also shall not include materials that at the time of or prior to disclosure in these proceedings, is or was publicly disclosed, on a non-confidential basis. The disclosure of materials to a party, its customers, or their respective employees, agents, consultants, or counsel in the normal course of business shall not preclude a claim that such materials are protected materials hereunder. Protected materials disclosed by someone other than an employee, agent, or consultant of the originating party in violation of this Protective Agreement shall not lose their status as protected material as a result of such disclosure.

3. Definition of “reviewing party”

A “reviewing party” is defined for purposes of this Protective Agreement as a party to the city-level Statement of Intent proceeding filed by West Texas Gas Utility, LLC (“WTGU”), including WTGU or a representative for a city within the Texas Area, or other party with standing to participate in the proceeding.

4. Definition of “producing party”

A “producing party” is defined for purposes of this Protective Agreement as WTGU, a city within the Texas Area, or any other party with standing to participate in the proceeding.

5. Access to Protected Materials

A reviewing party shall be permitted access to protected materials only through its authorized representatives. “Authorized representatives” of a party include its counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by the party and directly engaged in these proceedings, provided that such person has signed the certification required by Paragraph 8.

6. Designation of Highly Sensitive Protected Materials

The term “highly sensitive protected materials” is a subset of “protected materials.” The term refers to, but is not limited to, documents and information the provision of which to the reviewing party or its authorized representatives would: (1) expose the producing party or any of its affiliates to an unreasonable risk of harm, or (2) would result in disclosure of information that would be subject to a privilege against disclosure, a contractual confidentiality agreement or other Protective Agreement. Highly sensitive protected materials further include, but are not limited to, business operations or financial information that is commercially sensitive. Documents so classified by a producing party shall bear the designation “HIGHLY SENSITIVE PROTECTED MATERIALS PROVIDED PURSUANT TO THE PROTECTIVE AGREEMENT.”

7. Restrictions on Copies and Inspection of Highly Sensitive Protected Materials

Highly sensitive protected materials shall be made available for inspection only at the address specified pursuant to Paragraph 9. Additionally, only one copy of highly sensitive protected materials shall be provided to counsel of any party to this proceeding upon written request following completion of the certifications required by Paragraph 8 herein. A party may make one additional copy of reproduced highly sensitive protected materials for use in this proceeding pursuant to this Protective Agreement. No additional copies of such highly sensitive protected materials may be made, except that additional copies may be made in order to have sufficient copies for introduction of the material into the evidentiary record if the material is to be offered for admission into the record. A record of any copies that are made of highly sensitive protected material shall be kept and a copy of the record shall be sent to the producing party upon request. The record shall include information on the location and the person in possession of the copy. The authorized representatives for the purpose of access to highly sensitive protected materials must be persons who are: (1) counsel for the reviewing party, (2) consultants for the reviewing party working under the direction of the reviewing party’s counsel, (3) permanent non-elected employees of municipalities that are parties in this proceeding, who have primary responsibility for utility regulation. The authorized representatives for the Cities for the purpose of access to these materials shall consist of its respective counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by those agencies and directly engaged in this proceeding. Limited notes may be made of highly sensitive protected materials, and such notes shall themselves be treated as highly sensitive protected material unless such notes are restricted to a description of the document and a general characterization of its subject matter in a manner that does not include any substantive information contained in such highly sensitive protected materials.

8. Required Certification

Each person who inspects the protected materials shall, before such inspection, agree in writing to follow certification set forth in Exhibit A to this Agreement:

I certify my understanding that the protected materials are provided to me pursuant to the terms and restrictions of the Protective Agreement in this proceeding, and that I have been given a copy of it and have read the Protective Agreement and agree to be bound by it. I understand that the contents of the protected materials, any notes, memoranda, or any other form of information regarding or derived from the protected materials shall not be disclosed to anyone other than in accordance with the Protective Agreement and shall be used only for the purpose of this proceeding. If the information contained in the protected materials is obtained from independent sources that did not obtain such information from documents obtained in this proceeding, the understanding stated herein shall not apply.

In addition, reviewing parties who are permitted access to highly sensitive protected material under the terms of this ruling shall, before inspection of such materials, agree in writing to the following certification set forth in Exhibit A to this Protective Agreement:

I certify that I am eligible to have access to highly sensitive protected materials under the terms of the Protective Agreement in this proceeding.

A copy of each signed certification shall be provided to counsel for the party asserting confidentiality. Except for highly sensitive protected materials, any authorized representative may disclose protected materials to any other person who is an authorized representative, provided that, if the person to whom disclosure is to be made has not executed and provided for delivery of a signed certification to the party asserting confidentiality, that certification shall be executed prior to any disclosure. An authorized representative may disclose highly sensitive protected material to other reviewing representatives who are permitted access to such materials and have executed the additional certification required for persons who receive access to highly sensitive protected material. In the event that any authorized representative to whom protected materials are disclosed ceases to be engaged in these proceedings, access to protected materials by that person shall be terminated and all notes or memoranda or other information derived from the protected material shall be returned to the party on whose behalf that person was acting. Any person who has agreed to either or both of the foregoing certifications shall continue to be bound by the provisions of this Protective Agreement, even if no longer engaged in these proceedings. Parties who assert confidentiality shall maintain a list of persons who sign a certification pursuant to this Paragraph.

9. Voluminous Materials

(a) Voluminous protected materials which exceed eight linear feet shall be made available for inspections in its normal repository between the hours of 9:30 a.m. and 5:00 p.m., Monday through Friday (except holidays) in accordance with the Texas Rules of Civil Procedure. A party shall notify the other parties of the address at which the voluminous data will be produced simultaneously with the production of such data. For purposes of this Protective Agreement

voluminous materials or data shall mean responses to a particular question or subpart that consist of one hundred pages or more in the aggregate.

(b) Except for highly sensitive protected materials as provided for in Paragraph 7, and for protected materials that are voluminous, the party asserting confidentiality shall provide a party one copy of the protected materials upon receipt of the signed certifications described in Paragraph 8. Except as provided above for highly sensitive protected materials, parties may take notes regarding the information contained in protected materials made available for inspection pursuant to Paragraph 9(a). Only one copy of such protected materials shall be reproduced for each party. Parties shall make a diligent, good-faith effort to limit the amount of copying requested to only that which is appropriate for purposes of this proceeding. Notwithstanding the foregoing provisions of this Paragraph 9(b), a party may make further copies of reproduced protected materials for use in this proceeding pursuant to this Protective Agreement, but a record shall be maintained as to the documents produced and the number of copies made, and upon request, the party shall provide the party asserting confidentiality with a copy of that record.

10. Availability for Purposes of this Filing

All protected materials shall be made available to the Cities solely for the purposes of this proceeding. Protected materials, as well as a party's notes, memoranda, or other information regarding, or derived from the protected materials are to be treated confidentially by the parties and shall not be disclosed or used by the party except as permitted and provided in this Protective Agreement. Information derived from or describing the protected materials shall be maintained in a secure place and shall not be placed in the public or general files of the party except in accordance with the provisions of this Protective Agreement. Cities must take all reasonable precautions to ensure that the protected materials, including notes and analysis made from protected materials, are not viewed or taken by any person other than an authorized representative of the Cities.

11. Changes to Protective Agreement

Nothing herein restricts the party seeking protected material and the party producing the protected material from agreeing to other procedures/methods for handling of protected material, including highly sensitive protected material. In addition, each party shall have the right to seek changes in this Protective Agreement as appropriate from the Examiners, the Commission, or the courts. Nothing herein shall prevent any party from opposing efforts to seek changes to this ruling.

12. Objection to Protected Materials

Nothing in this ruling shall be construed as precluding any party from objecting to the use of protected materials on grounds other than confidentiality, including the lack of required relevance. Nothing in this ruling shall be construed as an agreement by any party that the protected materials are entitled to confidential classification.

13. Acts Upon Conclusion of Proceeding

Following the conclusion of these proceedings, each party must, no later than thirty days following receipt of the notice described below, destroy or return to the party asserting confidentiality all copies of the protected materials provided by that party pursuant to this Protective Agreement and all copies reproduced by a reviewing party, and counsel for each party must provide to the party asserting confidentiality a verified certification that, to the best of his or her knowledge, information, and belief, all copies of notes, memorandum, and other documents regarding or derived from the protected materials (including copies of protected materials) that have not been so returned, if any, have been destroyed, other than notes, memoranda, or other documents which contain information in a form which, if made public, would not cause disclosure of protected materials. Promptly following the conclusion of this proceeding, counsel for the party asserting confidentiality will send a written notice to all parties, reminding them of their obligations under this Paragraph. Nothing in this Paragraph shall prohibit counsel for each party from retaining two copies of any filed testimony, exhibit, brief, application for rehearing, or other pleading which refers to protected materials provided that any such protected materials retained by counsel shall remain subject to the provisions of this ruling. As used in this Paragraph, “conclusion of this proceeding” refers to the exhaustion of available appeals, or the running of the time for making of such appeals, as provided by applicable law. If, following any appeal, the Commission or Regulatory authority conducts a remand proceeding, then “the conclusion of these proceedings” is extended by the remand to the exhaustion of available appeals, or the running of the time for the making of such appeals, as provided by applicable law.

14. Compliance with Legal Requirements

This Protective Agreement is subject to the requirements of the Public Information Act, the Open Meetings Act, and any other applicable law, provided that parties subject to those acts will give the party asserting confidentiality notice, if possible, under those acts, prior to disclosure pursuant to those acts.

15. Effect of Court Order

If required by order of a government or judicial body, the party may release to such body the confidential information required by such order, provided, however, the party agrees that prior to such disclosure, it shall promptly notify the party asserting confidentiality of the order and allow such party sufficient time to contest release of the confidential information; provided, further, the party shall use its best efforts to prevent such confidential information from being disclosed.

The term “best efforts” as used in the preceding paragraph requires that the party’s attempt to ensure that disclosure is not made by its employees or authorized representatives unless such disclosure is pursuant to a final order of a governmental or judicial body or written opinion of the Attorney General which was sought in compliance with V.T.C.A., Government Code §552.301 (Public Information). The party is not required to delay compliance with a lawful order to disclose such information but is simply required to timely notify the party asserting confidentiality, or its counsel, that it has received a challenge to the confidentiality of the information and that the reviewing party will either proceed under the provisions of §552.301 of the Texas Government Code or intends to comply with the final governmental or court order.

16. Effect of Violation of Court Order

In the event of a breach of the provisions contained in Paragraph 15, the party asserting confidentiality will not have an adequate remedy in money or damages, and accordingly, shall in addition to any other available legal or equitable remedies, be entitled to an injunction against such breach. The producing party shall not be relieved of proof of any element required to establish the right to injunctive relief.

EXHIBIT A
CERTIFICATIONS

Certification for Protected Materials Only:

I certify my understanding that the protected materials are provided to me pursuant to the terms and restrictions of the Protective Agreement in this proceeding, and that I have been given a copy of it and have read the Protective Agreement and agree to be bound by it. I understand that the contents of the protected materials, any notes, memoranda, or any other form of information regarding or derived from the protected materials shall not be disclosed to anyone other than in accordance with the Protective Agreement and shall be used only for the purpose of this proceeding. If the information contained in the protected materials is obtained from independent sources that did not obtain such information from documents obtained in this proceeding, the understanding stated herein shall not apply.

_____ Signature	_____ Party Represented
_____ Printed Name	_____ Date

Additional Certification for Highly Sensitive Protected Materials:

I certify that I am eligible to have access to highly sensitive protected materials under the terms of the Protective Agreement in this proceeding.

_____ Signature	_____ Party Represented
_____ Printed Name	_____ Date

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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BASE RATE REVENUE REQUIREMENTS

<u>Description</u>	<u>Reference Schedule</u>	<u>Adjusted Texas Amounts</u>	<u>Jurisdictional</u>		<u>Non-Jurisdictional</u>
			<u>Domestic</u>	<u>Non-Domestic</u>	
O&M Expenses	Schedule B-1	10,696,368	6,209,274	1,595,221	2,891,873
A&G Expenses	Schedule B-2	5,576,542	3,432,439	952,287	1,191,816
Taxes Other than Income	Schedule B-3	2,792,222	1,633,544	445,390	713,288
Depreciation Expense	Schedule D	5,211,043	2,959,015	975,652	1,276,376
Return on Investment					
Rate Base	Schedule C	119,850,523			
Rate of Return	Schedule E	8.10%			
Return	Schedule F	<u>9,713,453</u>	5,795,757	1,995,774	1,921,923
Net Income Tax Expense	Schedule F	1,713,989	1,022,691	352,165	339,133
Other Gas Income	Schedule G	(1,087,324)	(685,011)	(218,067)	(184,245)
Base Rate Revenue Requirements		<u>34,616,294</u>	<u>20,367,710</u>	<u>6,098,421</u>	<u>8,150,163</u>
Base Rate Revenues at Current Rates	Schedule A-2		<u>10,183,324</u>	<u>3,005,044</u>	
Base Rate Revenues at Requested Rates	Schedule A-2		<u>14,510,622</u>	<u>5,456,636</u>	
Cost-Based Rate Increase:					
Amount	Schedule A-2		10,184,386	3,093,378	
Percentage			100.0%	102.9%	
WGTU Proposed Rate Increase:					
Amount	Schedule A-2		4,327,298	2,451,592	
Percentage			42.5%	81.6%	

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule A-1
Page 1 of 1

CALCULATION OF COST-BASED RATES

Description	Reference	DOMESTIC CUSTOMERS		NON-DOMESTIC CUSTOMERS	
		Base Rate Calculation	Cost of Service	Base Rate Calculation	Cost of Service
Cost of Service	Schedule J-B				
Customer-related Costs			15,405,551		2,470,463
Capacity-related Costs			4,962,159		3,627,958
Total Cost of Service			20,367,710		6,098,421
Monthly Customer Charge:					
Customer-related Costs			15,405,551		2,470,463
Number of Customers	Schedule K	17,924		2,484	
Months per year		12		12	
Annual No. of Bills			215,084		29,805
Cost-based Monthly Customer Charge			\$ 71.63		\$ 82.89
Consumption Charge:					
Capacity-related Costs			4,962,159		6,098,421
Annual Volumes -- Mcf	Schedule K		1,063,235		634,364
Cost-based Consumption Charge			\$ 4.67		\$ 9.61

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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BASE RATE REVENUE COMPARISON AT CURRENT, COST-BASED, AND PROPOSED RATES

Description	Reference	Current Base Rates			Cost-Based Base Rates		Proposed Base Rates	
		Unadjusted	Weather Adjustment	Adjusted	Cost-Based	% Increase	Proposed	% Increase
<u>Domestic Customers</u>								
Number of Domestic Customers	Schedule K	17,924		17,924	17,924		17,924	
Months per year		12		12	12		12	
Annual No. of Bills		215,084		215,084	215,084		215,084	
Domestic Customer Charge		\$ 23.42		\$ 23.42	\$ 71.63	205.8%	\$ 29.50	26.0%
Monthly Customer Charge Revenues		5,037,267		5,037,267	15,405,551		6,344,978	
Domestic Volumes -- Mcfs	Schedule K	1,007,056	56,179	1,063,235	1,063,235		1,063,235	
Domestic Consumption Charge		\$ 4.84		\$ 4.84	\$ 4.67	-3.6%	\$ 7.68	58.7%
Consumption Charge Revenues		4,874,153		5,146,057	4,962,159		8,165,644	
Total Domestic Revenues		9,911,420		10,183,324	20,367,710	100.0%	14,510,622	42.5%
<u>Non-Domestic Customers</u>								
Number of Non-Domestic Customers	Schedule K	2,484		2,484	2,484		2,484	
Months per year		12		12	12		12	
Annual No. of Bills		29,805		29,805	29,805		29,805	
Non-Domestic Customer Charge		\$ 43.57		\$ 43.57	\$ 82.89	90.2%	\$ 79.00	81.3%
Monthly Customer Charge Revenues		1,298,604		1,298,604	2,470,463		2,354,595	
Non-Domestic Volumes -- Mcfs	Schedule K	601,671	32,693	634,364	634,364		634,364	
Non-Domestic Consumption Charge		\$ 2.69		\$ 2.69	\$ 9.61	257.4%	\$ 4.89	81.8%
Consumption Charge Revenues		1,618,495		1,706,440	6,098,421		3,102,041	
Total Non-Domestic Revenues		2,917,099		3,005,044	8,568,884	185.2%	5,456,636	81.6%
TOTAL JURISDICTIONAL REVENUES		12,828,519		13,188,368	28,936,594	119.4%	19,967,258	51.4%

WEST TEXAS GAS, INC.
Test Period Ending December 31, 2019

Corrected Schedule A-3
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SUMMARY OF ADJUSTMENTS

Purpose of Adjustment	Affected Accounts	Reference	Amount of Adjustment
Revenues			
To weather normalize volumes	Domestic Customers	Schedules A-2 and K	271,904
To weather normalize volumes	Non-Domestic Customers	Schedules A-2 and K	87,945
O&M Expenses			
To remove amounts related to Oklahoma operations	All O&M expense accounts	Schedules B-1 and B-4	(1,131,411)
To remove gas transportation costs included in cost of gas	Account 858 - Trans. & Comp. of Gas by Others	Schedule B-1	(347,264)
To remove Donations and Contributions	Account 888 -- Other Expenses	Schedules B-1 and H-5	(26,370)
A&G Expenses			
To remove amounts related to Oklahoma operations	All A&G expense accounts	Schedules B-2 and B-4	(612,508)
To include Interest expense on Customer Deposits	Account 910 -- Customer Service Expense	Schedule B-2	30,504
To remove Penalties and Fines	Account 921 -- Office Supplies and Expenses	Schedules B-2 and H-7	(24,117)
To remove Entertainment, Meals, Lodging, and Travel expenses.	Account 921 -- Office Supplies and Expenses	Schedule B-2	(35,971)
To remove Lobbying expenses	Account 923 -- Outside Services Employed	Schedules B-2 and H-6	(10,219)
To remove Donations and Contributions	Account 930 -- Miscellaneous General Expenses	Schedules B-2 and H-5	(38,070)
To remove Entertainment, Meals, Lodging, and Travel expenses.	Account 930 -- Miscellaneous General Expenses	Schedule B-2	(166,469)
Taxes Other than Income			
To remove amounts related to Oklahoma operations	All Other Tax accounts except Texas Franchise	Schedules B-3 and B-4	(426,667)
Rate Base			
Plant in Service			
To remove plant related to Oklahoma operations	Various plant accounts	Schedules C and C-1	(19,170,874)
To remove acquisition adjustments	Account 303	Schedules C and C-1	(20,621,198)
To remove non-utility assets	Accounts 332 and 389.1	Schedules C and C-1	(1,293,000)
To reclassify assets.	Accounts 366,369,392,394,396,398	Schedules C and C-1	0
To remove retired assets.	Accounts 391,392,394,397,398	Schedules C and C-1	(1,397,372)
Accumulated Depreciation			
To remove acc. depreciation related to Oklahoma operations	Various plant accounts	Schedules C and C-2	(8,413,221)
To remove acquisition adjustments	Account 303	Schedules C and C-2	(3,798,361)
To reclassify assets.	Accounts 366,369,392,394,396,398	Schedules C and C-2	-
To remove retired assets.	Accounts 391,392,394,397,398	Schedules C and C-2	(1,988,539)
Working Capital			
To adjust December 31, 2023 balance to test year average	Account 165 -- Pr repayments	Schedules C and C-3	258,321
To adjust December 31, 2023 balance to test year average	Account 154 -- Plant Materials and Operating Supplies	Schedules C and C-3	68,456
Non-Investor Supplied Capital			
To record Accumulated Deferred Income Taxes	Account 281 -- Accumulated DIT -- Accelerated Depreciation	Schedules C	(25,703,718)
To record Excess Accumulated Deferred Income Taxes	Account 283 -- Accumulated DIT -- Other	Schedules C and C-4	(9,311,525)
Depreciation Expense			
To reflect proposed depreciation rates	Account 403 -- Depreciation Expense	Schedule D	(656,628)
Other Income			
To remove other income related to Oklahoma operations	Account 488 -- Miscellaneous Service Revenues	Schedule G-1	(205,742)

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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EXPENSES BY MONTH (a)

Acct. No.	Description	2023												Total
		January	February	March	April	May	June	July	August	September	October	November	December	
OPERATIONS AND MAINTENANCE EXPENSES														
<u>Transmission Expense</u>														
813.0	Other Gas Supply Expenses	3,100	2,091	10,457	-	33,832	-	-	2,960	30,057	44	36,502	38,120	157,163
858.0	Trans. & Comp. Of Gas by Others	18,560	20,549	27,861	33,136	32,780	34,711	32,535	35,800	35,977	29,771	27,101	18,484	347,264
863.0	Maintenance of Mains	140	28,843	53,492	45,102	2,358	27,875	19,330	13,934	17,412	16,818	2,639	(130,789)	97,154
<u>Distribution Expense</u>														
870.0	Operation Supervision & Engineering	561,280	595,023	889,984	591,813	594,268	593,465	626,737	966,379	642,027	610,049	609,516	498,143	7,778,684
874.0	Mains and Services Expenses	106,346	116,608	136,290	115,543	34,400	171,761	200,749	54,978	131,323	126,409	34,389	(30,389)	1,198,406
880.0	Other Expenses	80,080	69,386	83,518	75,622	50,883	68,623	121,295	75,822	82,647	39,946	84,941	80,702	913,465
881.0	Rents	22,345	19,308	15,118	13,585	16,738	14,202	17,150	20,917	17,807	20,522	19,656	21,973	219,320
886.0	Maintenance of Structures	437	5,474	396	548	-	39	-	62	529	2,009	21	14	9,528
887.0	Maintenance of Mains	12,433	65,917	19,584	25,328	8,740	25,060	12,527	69,605	57,225	69,256	39,207	22,423	427,305
888.0	Maint of M&R Station Equip-General	726	-	31	-	-	725	173	725	28	-	-	-	2,407
889.0	Maint of M&R Station Equip-City Gate	92,943	114,499	65,640	47,570	15,487	101,614	39,156	164,799	170,722	52,328	53,601	(416,699)	501,661
894.0	Maintenance of Other Equipment	54,537	29,913	36,960	27,275	20,712	45,273	48,039	25,918	83,871	46,185	45,403	84,968	549,056
ADMINISTRATIVE AND GENERAL EXPENSES														
<u>Customer Service and Sales Expenses</u>														
904.0	Uncollectible Accounts	20,875	13,820	16,046	16,293	13,034	8,956	17,800	23,506	16,814	11,853	11,174	10,441	180,612
910.0	Miscellaneous Customer Service Exp	753	4,937	54,533	33,807	1,100	500	799	3,963	150	-	1,150	-	101,692
913.0	Advertising Expenses	879	6,384	1,682	2,195	1,543	2,096	84	1,225	1,787	2,144	-	1,374	21,392
<u>Administrative and General Expenses</u>														
920.0	Administrative and General Salaries	101,032	106,422	160,695	104,682	104,043	103,336	101,969	106,384	67,449	107,485	107,317	196,228	1,367,041
921.0	Office Supplies and Expenses	21,804	6,985	15,163	14,213	27,450	11,376	64,583	13,343	28,725	9,083	14,773	27,832	255,330
922.0	Administrative Expenses Transferred-Credit	-	-	-	-	-	-	-	-	-	-	-	(1,230,375)	(1,230,375)
923.0	Outside Services Employed	125,321	83,284	101,836	204,721	116,558	222,752	142,962	159,546	88,163	144,491	110,032	163,351	1,663,018
924.0	Property Insurance	50,429	50,429	61,476	54,097	55,965	171,012	87,174	85,506	85,506	121,437	84,704	47,055	954,789
926.0	Employee Pension and Benefits	128,813	114,756	168,295	115,522	123,002	113,014	117,597	168,138	130,170	142,366	115,176	123,505	1,560,354
930.0	Miscellaneous General Expense	101,164	109,490	132,188	270,999	79,846	67,410	121,125	139,768	192,231	134,612	143,735	60,090	1,552,657
931.0	Rents	4,690	1,544	-	1,547	-	-	-	-	2,740	1,627	-	(5,266)	6,882
TAXES OTHER THAN INCOME														
<u>Payroll Taxes:</u>														
408.2	Payroll Taxes	68,363	64,164	54,727	51,653	51,647	51,430	53,760	78,580	51,451	51,268	50,781	48,520	676,344
<u>Property Taxes:</u>														
408.2	Property Taxes	132,973	132,973	132,922	136,398	132,973	551,770	159,139	132,973	132,973	162,517	133,162	432,187	2,372,959
<u>Other Taxes:</u>														
408.2	Texas Franchise Tax	-	-	-	42,064	-	-	-	-	-	-	9,967	-	52,031
408.2	Miscellaneous	12,865	23,693	6,682	4,327	16,358	3,015	2,936	14,329	2,865	14,731	5,718	10,036	117,555

(a) WTG books and records (detail is contained in electronic workpapers provided separately).

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OPERATIONS AND MAINTENANCE EXPENSES

Acct. No.	Description	Test Year WTG Total (a)	Adjustments	Ref.	Oklahoma (d)	Adjusted Texas
<u>Transmission Expense</u>						
813.0	Other Gas Supply Expenses	157,163	-		-	157,163
858.0	Trans. & Comp. Of Gas by Others	347,264	(347,264)	(b)	-	-
863.0	Maintenance of Mains	97,154	-		(733)	96,421
		-				
<u>Distribution Expense</u>						
870.0	Operation Supervision & Engineering	7,778,684	-		(811,654)	6,967,030
874.0	Mains and Services Expenses	1,198,406	-		(78,991)	1,119,415
880.0	Other Expenses	913,465	(26,370)	(c)	(97,238)	789,857
881.0	Rents	219,320	-		(18,624)	200,696
886.0	Maintenance of Structures	9,528	-		(2,000)	7,528
887.0	Maintenance of Mains	427,305	-		(32,093)	395,212
888.0	Maint of M&R Station Equip-General	2,407	-		(158)	2,249
889.0	Maint of M&R Station Equip-City Gate	501,661	-		(61,250)	440,411
894.0	Maintenance of Other Equipment	549,056	-		(28,671)	520,385
	Totals	12,201,412	(373,633)		(1,131,411)	
	Operation & Maintenance Expenses					10,696,368

(a) Schedule B.

(b) To remove amounts included in cost of gas.

(c) To remove donations and contributions (Schedule H-5).

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule B-2
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ADMINISTRATIVE AND GENERAL EXPENSES

Acct. No.	Description	Test Year WTG Total (a)	Adjustments	Ref.	Oklahoma (g)	Adjusted Texas
<u>Customer Service and Sales Expenses</u>						
904.0	Uncollectible Accounts	180,612	-		(17,862)	162,750
910.0	Miscellaneous Customer Service Exp	101,692	30,504	(b)	(8,372)	123,824
913.0	Advertising Expenses	21,392	-		(239)	21,153
<u>Administrative and General Expenses</u>						
920.0	Administrative and General Salaries	1,367,041	-		(125,499)	1,241,542
921.0	Office Supplies and Expenses	255,330	(60,088)	(c)(d)	(21,931)	173,311
922.0	Administrative Expenses Transferred-Credit	(1,230,375)	-		112,952	(1,117,423)
923.0	Outside Services Employed	1,663,018	(10,219)	(e)	(152,671)	1,500,128
924.0	Property Insurance	954,789	-		(87,653)	867,137
926.0	Employee Pension and Benefits	1,560,354	-		(142,225)	1,418,128
930.0	Miscellaneous General Expense	1,552,657	(204,539)	(d)(f)	(167,769)	1,180,349
931.0	Rents	6,882	-		(1,240)	5,641
Totals		6,433,393	(244,343)		(612,508)	
Administrative and General Expenses						<u>5,576,542</u>

- (a) Schedule B.
(b) To include interest on customer deposits.
(c) To remove penalties and fines (Schedule H-7).
(d) To remove entertainment, meals, lodging, and travel expenses.
(e) To remove lobbying expenses (Schedule H-6).
(f) To remove donations and contributions (Schedule H-5).
(g) Composite Corporate Allocation Factor (Schedule B-4).

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule B-3
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TAXES OTHER THAN INCOME

Acct. No.	Description	Test Year WTG Total (a)	Adjustments	Ref.	Oklahoma (b)	Adjusted Texas
<u>Payroll Taxes:</u>						
408.2	Payroll Taxes	676,344	-		(74,266)	602,078
<u>Property Taxes:</u>						
408.2	Property Taxes	2,372,959	-		(345,921)	2,027,037
<u>Other Taxes:</u>						
408.2	Texas Franchise Tax	52,031	-		-	52,031
408.2	Miscellaneous	117,555	-		(6,479)	111,076
Totals		3,218,888	-		(426,667)	
Taxes Other than Income						<u><u>2,792,222</u></u>

(a) Schedule B.

(b) Schedule B-4.

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Schedule B-4
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ALLOCATION OF O&M, A&G, AND OTHER TAXES TO OKLAHOMA

Acct. No.	Description	Region 40		Region 70		WTGU		Total Oklahoma
		Total (a)	Oklahoma	Total (a)	Oklahoma	Total (a)	Oklahoma	
Allocation Factors:								
	Average Number of Customers (a)	4,312	78	6,633	4,509	28,108	4,587	
	Oklahoma Customers as % of Total		1.81%		67.98%		16.32%	
	Gross Plant (Schedule C-1)					291,649,056	19,170,874	
	Oklahoma Plant as % of Total						6.57%	
	O&M Expenses (Schedule B-1)					11,827,779	1,131,411	
	Oklahoma O&M Expenses as % of Total						9.57%	
	Revenues (a)					144,743,978	6,170,411	
	Oklahoma Revenues as % of Total						4.26%	
	Composite Corporate Allocation Factor						9.18%	
Operations and Maintenance Expenses (b)								
813.0	Other Gas Supply Expenses	-	-	-	-	-	-	-
858.0	Trans. & Comp. Of Gas by Others	-	-	-	-	-	-	-
863.0	Maintenance of Mains	40,529	733	-	-	-	-	733
870.0	Operation Supervision & Engineering	1,080,587	19,547	1,155,069	785,196	75,278	6,911	811,654
874.0	Mains and Services Expenses	84,852	1,535	113,943	77,456	-	-	78,991
880.0	Other Expenses	126,267	2,284	139,755	95,003	(538)	(49)	97,238
881.0	Rents	10,508	190	27,118	18,434	-	-	18,624
886.0	Maintenance of Structures	1,942	35	2,890	1,965	-	-	2,000
887.0	Maintenance of Mains	31,925	577	46,361	31,515	-	-	32,093
888.0	Maint of M&R Station Equip-General	2,234	40	173	118	-	-	158
889.0	Maint of M&R Station Equip-City Gate	96,361	1,743	87,538	59,507	-	-	61,250
894.0	Maintenance of Other Equipment	45,917	831	38,519	26,185	18,034	1,656	28,671
	Total	1,521,122	27,516	1,611,366	1,095,379	92,774	8,517	1,131,411
Administrative and General Expenses (c)								
904.0	Uncollectible Accounts	10,807	195	25,989	17,667	-	-	17,862
910.0	Miscellaneous Customer Service Exp	-	-	-	-	91,190	8,372	8,372
913.0	Advertising Expenses	435	8	340	231	-	-	239
920.0	Administrative and General Salaries	-	-	-	-	1,367,041	125,499	125,499
921.0	Office Supplies and Expenses	-	-	-	-	238,887	21,931	21,931
922.0	Administrative Expenses Transferred-Credi	-	-	-	-	(1,230,375)	(112,952)	(112,952)
923.0	Outside Services Employed	-	-	-	-	1,663,018	152,671	152,671
924.0	Property Insurance	-	-	-	-	954,789	87,653	87,653
926.0	Employee Pension and Benefits	-	-	894	607	1,542,625	141,618	142,225
930.0	Miscellaneous General Expense	100,598	1,820	201,727	137,130	313,926	28,819	167,769
931.0	Rents	-	-	-	-	13,512	1,240	1,240
	Total	111,840	2,023	228,949	155,635	4,954,613	454,850	612,508
Taxes Other than Income (c)								
408.2	Payroll Taxes	80,998	1,465	86,157	58,568	155,038	14,233	74,266
408.2	Property taxes	104,308	1,887	506,094	344,034	-	-	345,921
408.2	Other	17,360	314	9,070	6,165	-	-	6,479
	Total	202,666	3,666	601,321	408,768	155,038	14,233	426,667

(a) Schedule K and WTG books and records (detail is contained in electronic workpapers provided separately).

(b) Allocated based on number of customers.

(c) Regions 40 and 70 allocated based on number of customers; Corporate allocated using composite allocation factor.

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule C
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RATE BASE							
December 31, 2023							
Description	Reference	WTG Total	Oklahoma	Texas	Adjustments	Ref.	Adjusted Texas
Plant in Service:							
Plant in Service	Schedule C-1	291,649,056	(19,170,874)	272,478,182	(23,311,570)		249,166,612
Accumulated Depreciation	Schedule C-2	(87,190,168)	8,413,221	(78,776,946)	5,786,900		(72,990,047)
Net Plant in Service		204,458,888		193,701,235			176,176,565
Construction Work in Progress	(a)	5,407,013	-	5,407,013	(5,407,013)	(b)	-
Working Capital:							
Cash Working Capital Allowance		-	-	-	-	(c)	-
Prepayments	Schedule C-3	1,016,495	(93,318)	923,177	258,321	(d)	1,181,498
Materials and Supplies Inventories	Schedule C-3	1,963,405	(180,247)	1,783,158	68,456	(d)	1,851,614
Non-Investor Supplied Capital:							
Customer Deposits	(a)	(1,508,997)	308,437	(1,200,560)	-		(1,200,560)
Contributions in Aid of Construction	(a)	(23,804,581)	661,231	(23,143,350)	-		(23,143,350)
Accumulated Deferred Income Taxes		-	-	-	(25,703,718)	(e)	(25,703,718)
Excess ADIT	Schedule C-4				(9,311,525)		(9,311,525)
RATE BASE							<u>119,850,523</u>

- (a) WTG books and records (detail is contained in electronic workpapers provided separately).
- (b) No construction work in progress (CWIP) is being requested to be included in rate base.
- (c) No cash working capital allowance is being requested to be included in rate base.
- (d) To adjust December 31, 2023 balance to average during the test year.
- (e) To record Accumulated Deferred Income Taxes (ADIT) at December 31, 2023:

Total Net Plant in Service	204,458,888	
Net Tax Basis of Total Plant in Service (a)	<u>34,102,237</u>	
Timing Difference		170,356,651
Corporate Income Tax Rate		21%
Total ADIT Liability		<u>35,774,897</u>
Adjusted Texas Plant in Service	249,166,612	
Total Plant in Service	<u>291,649,056</u>	
Percent Applicable to Texas		<u>85.43%</u>
Texas ADIT Liability		<u>30,563,822</u>
Texas Contributions in Aid of Construction	23,143,350	
Corporate Income Tax Rate	21%	
Texas ADIT Asset		<u>4,860,104</u>
Net Texas ADIT Liability		<u>25,703,718</u>

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule C-1
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PLANT IN SERVICE

Acct. No.	Description	12/31/2023	Oklahoma		Texas	Adjustments	Ref.	Adjusted
		WTGU Total (a)	Direct (a)	Allocated (b)				Texas
Production and Gathering Plant								
301.0	Organization	57,872	-	-	57,872			57,872
302.0	Franchises and Consents	200,000	-	-	200,000			200,000
303.0	Intangible Plant	22,388,083	(1,388,571)	(36,449)	20,963,064	(20,621,198)	(c)	341,866
332.0	Field Lines	3,048,811	-	-	3,048,811	(1,000)	(d)	3,047,811
334.0	Field M&R Station Equipment	100,000	-	-	100,000			100,000
Transmission Plant								
365.0	Land and Rights-of-Way	5,379,123	-	-	5,379,123			5,379,123
366.0	Structures and Improvements	149,596	-	-	149,596	(149,596)	(e)	-
367.0	Mains	45,312,827	-	-	45,312,827			45,312,827
368.0	Compressor Station Equipment	38,984	-	-	38,984			38,984
369.0	M&R Station Equipment	1,263,865	-	-	1,263,865	149,596	(e)	1,413,460
371.0	Other Equipment	224,148	-	-	224,148			224,148
Distribution Plant								
376.0	Mains	183,679,328	(15,777,824)	(1,840)	167,899,665			167,899,665
377.0	Compressors	358,854	(638)	-	358,216			358,216
378.0	M&R Station Equipment - General	8,597,576	(899,062)	(5,545)	7,692,969			7,692,969
387.0	Other Equipment	815,942	(127,844)	(463)	687,636			687,636
General Plant								
389.0	Rights-of-Way	6,308,629	-	-	6,308,629			6,308,629
389.1	Land	1,500,401	(12,000)	(5,519)	1,482,882	(1,292,000)	(d)	190,882
390.0	Office Buildings	4,604,940	(42,094)	-	4,562,846			4,562,846
391.0	Office Furniture and Equipment	454,910	(32,125)	(1,259)	421,526	(149,149)	(f)	272,377
392.0	Transportation Equip	4,546,739	(432,484)	(12,419)	4,101,836	(1,201,649)	(e)(f)	2,900,187
394.0	Tools, Shop & Garage	1,524,133	(77,981)	(51,188)	1,394,965	(232,380)	(e)(f)	1,162,584
396.0	Power Operated Equipment	-	-	-	-	356,492	(e)	356,492
397.0	Communication Equip	583,845	-	(6,354)	577,490	(54,358)	(f)	523,132
398.0	Miscellaneous Equip	510,451	(233,724)	(25,493)	251,234	(116,328)	(e)(f)	134,907
Plant in Service		291,649,056	(19,024,346)	(146,528)	272,478,182	(23,311,570)		249,166,612

(a) From WTGU books and records.

(b) Allocation of corporate general plant to Oklahoma:

	Corporate	Oklahoma
Oklahoma Plant as % of Total		6.52%
303.0 Intangible Plant	558,767	36,449
367.0 Mains	-	-
371.0 Other Equipment	28,206	-
376.0 Mains	85,009	1,840
378.0 M&R Station Equipment - General	7,092	5,545
387.0 Other Equipment	84,601	463
389.1 Land	19,300	5,519
391.0 Office Furniture and Equipment	190,394	1,259
392.0 Transportation Equip	784,721	12,419
394.0 Tools, Shop & Garage	97,414	51,188
397.0 Communication Equip	390,808	6,354
398.0 Miscellaneous Equip	17,602	25,493
Total	2,263,915	146,528

(c) To remove acquisition adjustments.

(d) To remove non-utility assets.

(e) To reclassify assets.

(f) To remove retired assets.

WEST TEXAS GAS UTILITY, LLC
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Schedule C-2
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ACCUMULATED DEPRECIATION

Acct. No.	Description	12/31/2023	Oklahoma		Texas	Adjustments	Ref.	Adjusted
		WTGU Total (a)	Direct (a)	Allocated (b)				Texas
Production and Gathering Plant								
301.0	Organization	57,872	-	-	57,872			57,872
302.0	Franchises and Consents	200,000	-	-	200,000			200,000
303.0	Intangible Plant	5,964,243	(1,487,753)	(51,790)	4,424,701	(3,798,361)	(c)	626,340
332.0	Field Lines	3,395,407	-	-	3,395,407			3,395,407
334.0	Field M&R Station Equipment	50,485	-	-	50,485			50,485
Transmission Plant								
365.0	Land and Rights-of-Way	612,078	-	-	612,078			612,078
366.0	Structures and Improvements	29,710	-	-	29,710	(29,710)	(d)	-
367.0	Mains	13,446,425	-	1	13,446,426			13,446,426
368.0	Compressor Station Equipment	49,512	-	-	49,512			49,512
369.0	M&R Station Equipment	770,132	-	-	770,132	29,710	(d)	799,842
371.0	Other Equipment	211,423	-	(1,028)	210,395			210,395
Distribution Plant								
376.0	Mains	46,385,879	(5,200,615)	(1,900)	41,183,364			41,183,364
377.0	Compressors	390,830	(770)	-	390,060			390,060
378.0	M&R Station Equipment - General	5,369,708	(432,734)	(435)	4,936,538			4,936,538
387.0	Other Equipment	619,581	(68,674)	(2,844)	548,063			548,063
General Plant								
389.0	Rights-of-Way	2,566,501	-	-	2,566,501			2,566,501
389.1	Land	-	-	-	-			-
390.0	Office Buildings	1,433,449	(54,836)	-	1,378,613			1,378,613
391.0	Office Furniture and Equipment	240,467	(22,771)	(6,228)	211,469	(138,779)	(e)	72,690
392.0	Transportation Equip	3,690,232	(695,100)	(26,306)	2,968,826	(1,773,863)	(d)(e)	1,194,963
394.0	Tools, Shop & Garage	892,166	(32,860)	(3,759)	855,547	(150,320)	(d)(e)	705,227
396.0	Power Operated Equipment	-	-	-	-	296,313	(d)	296,313
397.0	Communication Equip	316,334	-	(11,494)	304,840	(72,509)	(e)	232,331
398.0	Miscellaneous Equip	497,733	(310,911)	(414)	186,408	(149,381)	(d)(e)	37,027
Accumulated Depreciation		87,190,168	(8,307,025)	(106,196)	87,190,168	(5,786,900)		72,990,047

(a) From WTGU books and records.

(b) Allocation of accumulated depreciation on corporate general plant to Oklahoma:

	Corporate	Oklahoma
Oklahoma Plant as % of Total		6.52%
303.0 Intangible Plant	793,950	51,790
367.0 Mains	(12)	(1)
371.0 Other Equipment	15,757	1,028
376.0 Mains	29,122	1,900
378.0 M&R Station Equipment - General	6,669	435
387.0 Other Equipment	43,592	2,844
389.1 Land	-	-
391.0 Office Furniture and Equipment	95,473	6,228
392.0 Transportation Equip	403,275	26,306
394.0 Tools, Shop & Garage	57,625	3,759
397.0 Communication Equip	176,214	11,494
398.0 Miscellaneous Equip	6,353	414
Total	1,628,019	106,196

(c) To remove accumulated amortization of acquisition adjustments.

(d) To reclassify assets.

(e) To remove retired assets.

WEST TEXAS GAS UTILITY, LLC
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MATERIALS AND SUPPLIES INVENTORY

Description	WTG		Texas
	Total (a)	Oklahoma (b)	
Allocation percentage		9.18%	
<u>Account No. 165 -- Prepayments:</u>			
January	1,365,961	(125,400)	1,240,561
February	1,366,368	(125,437)	1,240,931
March	1,313,322	(120,567)	1,192,755
April	1,401,227	(128,637)	1,272,590
May	1,931,367	(177,306)	1,754,061
June	1,687,325	(154,902)	1,532,423
July	1,026,346	(94,222)	932,124
August	1,057,980	(97,126)	960,854
September	1,116,535	(102,502)	1,014,033
October	1,132,296	(103,948)	1,028,348
November	1,195,906	(109,788)	1,086,118
December	1,016,495	(93,318)	923,177
Average			1,181,498

Account No. 154 -- Materials & Supplies Inventory:

January	2,053,134	(188,484)	1,864,650
February	2,098,706	(192,668)	1,906,038
March	2,078,249	(190,790)	1,887,459
April	2,079,755	(190,928)	1,888,827
May	2,045,937	(187,824)	1,858,114
June	2,074,860	(190,479)	1,884,381
July	2,056,089	(188,756)	1,867,333
August	2,052,299	(188,408)	1,863,891
September	1,999,842	(183,592)	1,816,250
October	1,999,798	(183,588)	1,816,210
November	1,963,296	(180,237)	1,783,059
December	1,963,405	(180,247)	1,783,158
Average			1,851,614

(a) From WTG books and records.

(b) Composite Corporate Allocation Factor (Schedule B-4).

WEST TEXAS GAS UTILITY, LLC
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EXCESS ACCUMULATED DEFERRED INCOME TAXES (a)

Total Net Plant in Service -- December 31, 2017	140,852,236	
Net Tax Basis of Total Plant in Service -- December 31, 2017	25,432,543	
Timing Difference		115,419,693
Reduction in Corporate Income Tax Rate (35% -21%)		14%
Excess ADIT Liability -- December 31, 2017		16,158,757
Adjusted Texas Plant in Service -- December 31, 2017	162,118,443	
Total Plant in Service -- December 31, 2017	198,183,147	
Percent Applicable to Texas		81.80%
Texas Excess ADIT Liability		13,218,241
Texas Contributions in Aid of Construction -- December 31, 2017	9,869,155	
Reduction in Corporate Income Tax Rate (35% -21%)	14%	
Texas Excess ADIT Asset -- December 31, 2017		1,381,682
Net Texas Excess ADIT Liability -- December 31, 2017		11,836,559
Total Texas Net Plant in Service -- December 31, 2017	117,497,855	
Depreciation Expense on 2017 Year-end Texas Assets	4,177,538	
Remaining Life of Assets (years)		28.1
Ratable Amortization of Excess ADIT Liability		420,839
Net Texas Excess ADIT Liability -- December 31, 2017	11,836,559	
Ratable Amortization:		
2018	(420,839)	
2019	(420,839)	
2020	(420,839)	
2021	(420,839)	
2022	(420,839)	
2023	(420,839)	
Excess ADIT at December 31, 2023		9,311,525

(a) From WTG books and records.

WEST TEXAS GAS UTILITY, LLC
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GAS RELIABILITY INFRASTRUCTURE PROGRAM ADDITIONS

	Amounts (a)			Amounts (a)	
	Account	Total		Account	Total
January 1, 2020 - December 2020					
367.0 Mains	6,381,891		367.0 Mains	917,681	
369.0 M&R Station Equipment	11,106		369.0 M&R Station Equipment	54,113	
369.1 Meters	-		369.1 Meters	-	
376.0 Mains	11,201,810		376.0 Mains	13,106,529	
378.0 M&R Station Equipment - General	184,221		378.0 M&R Station Equipment - General	609,664	
387.0 Other Equipment	-		387.0 Other Equipment	17,947	
390.0 Office Buildings	113,047		390.0 Office Buildings	39,080	
391.0 Office Furniture and Equipment	2,596		391.0 Office Furniture and Equipment	4,292	
392.0 Transportation Equip	663,229		392.0 Transportation Equip	385,046	
394.0 Tools, Shop & Garage	57,576		394.0 Tools, Shop & Garage	76,615	
397.0 Communication Equip	42,766		397.0 Communication Equip	14,329	
398.0 Miscellaneous Equip	10,499		398.0 Miscellaneous Equip	69,771	
Total		18,668,741	Total		15,295,068
January 1, 2021 - December 2021					
367.0 Mains	14,575		367.0 Mains	130,064	
369.0 M&R Station Equipment	13,872		369.0 M&R Station Equipment	-	
369.1 Meters	3,828		369.1 Meters	8,760	
376.0 Mains	9,874,244		376.0 Mains	14,560,760	
378.0 M&R Station Equipment - General	123,182		378.0 M&R Station Equipment - General	868,969	
387.0 Other Equipment	3,765		387.0 Other Equipment	6,518	
390.0 Office Buildings	-		390.0 Office Buildings	7,473	
391.0 Office Furniture and Equipment	21,380		391.0 Office Furniture and Equipment	-	
392.0 Transportation Equip	607,217		392.0 Transportation Equip	-	
394.0 Tools, Shop & Garage	100,916		394.0 Tools, Shop & Garage	81,483	
397.0 Communication Equip	4,098		397.0 Communication Equip	18,201	
398.0 Miscellaneous Equip	24,652		398.0 Miscellaneous Equip	-	
Total		10,791,728	Total		15,682,229
January 1, 2023 - December 2023					

(a) WTG books and records (detail is contained in electronic workpapers provided separately).

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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DEPRECIATION EXPENSE

Acct. No.	Description	2023 Texas Total (a)	Adjusted Texas Plant (b)	Current Depreciation Rates		Proposed Depreciation Rates	
				Rate (c)	Depreciation	Rate (d)	Depreciation
Production and Gathering Plant							
301.0	Organization	57,872	57,872	-	-	-	-
302.0	Franchises and Consents	200,000	200,000	-	-	-	-
303.0	Intangible Plant	20,963,064	341,866	-	-	-	-
332.0	Field Lines	3,048,811	3,047,811	-	-	-	-
334.0	Field M&R Station Equipment	100,000	100,000	-	-	-	-
Transmission Plant							
365.0	Land and Rights-of-Way	5,379,123	5,379,123	2.211%	118,936	2.160%	116,171
366.0	Structures and Improvements	149,596	-	2.642%	-	-	-
367.0	Mains	45,312,827	45,312,827	2.541%	1,151,558	2.219%	1,005,482
368.0	Compressor Station Equipment	38,984	38,984	-	-	2.484%	968
369.0	M&R Station Equipment	1,263,865	1,413,460	2.594%	36,661	2.432%	34,372
371.0	Other Equipment	224,148	224,148	4.847%	10,865	3.830%	8,585
Distribution Plant							
376.0	Mains	167,899,665	167,899,665	2.606%	4,376,001	2.303%	3,866,825
377.0	Compressors	358,216	358,216	-	-	-	-
378.0	M&R Station Equipment - General	7,692,969	7,692,969	2.610%	200,817	2.412%	185,574
387.0	Other Equipment	687,636	687,636	3.813%	26,218	3.129%	21,513
General Plant							
389.0	Rights-of-Way	6,308,629	6,308,629	2.009%	126,754	1.818%	114,718
389.1	Land	1,482,882	190,882	-	-	-	-
390.0	Office Buildings	4,562,846	4,562,846	4.243%	193,603	2.726%	124,373
391.0	Office Furniture and Equipment	421,526	272,377	6.434%	17,524	5.000%	13,619
392.0	Transportation Equip	4,101,836	2,900,187	10.658%	309,113	10.460%	303,356
394.0	Tools, Shop & Garage	1,394,965	1,162,584	4.000%	46,503	4.000%	46,503
396.0	Power Operated Equipment	-	356,492	-	-	4.301%	15,334
397.0	Communication Equip	577,490	523,132	6.667%	34,875	8.333%	43,594
398.0	Miscellaneous Equip	251,234	134,907	6.667%	8,994	6.667%	8,994
Contributions in Aid of Construction (a)							
332.0	Field Lines	(272,521)	(272,521)	2.220%	(6,050)	2.220%	(6,050)
367.0	Mains	(1,909,128)	(1,909,128)	2.541%	(48,518)	2.219%	(42,363)
376.0	Mains	(28,246,138)	(28,246,138)	2.606%	(736,184)	2.303%	(650,525)
Totals		242,050,394	218,738,825	2.683%	5,867,672	2.382%	
Depreciation Expense							5,211,043

- (a) WTG books and records (detail is contained in electronic workpapers provided separately).
- (b) Schedule C-1.
- (c) GUD No. 10998.
- (d) Direct Testimony of Dane A. Watson.

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule E
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RATE OF RETURN

Description (a)	Percent	Component Cost	Weighted Cost
Debt	34.40%	3.06%	1.05%
Equity	65.60%	10.75%	7.05%
Total	100.00%		
OVERALL RATE OF RETURN			8.10%

(a) Direct Testimony of Bruce H. Fairchild.

WEST TEXAS GAS UTILITY, LLC
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INCOME TAX EXPENSE

<u>Description</u>	<u>Reference</u>	<u>Amount</u>
<u>Return on Investment:</u>		
Rate Base	Schedule C	119,850,523
Rate of Return	Schedule E	8.10%
Return on Investment		9,713,453
<u>Interest Expense:</u>		
Rate Base	Schedule C	119,850,523
Weighted Cost of Debt	Schedule E	1.05%
Interest Expense		(1,261,595)
Return on Equity		8,451,859
Amortization of Excess ADIT	Schedule C-4	(420,839)
Adjusted Return on Equity		8,031,020
Income Tax Factor	$(1 + (21\% / (1 - 21\%)))$	1.2658
Taxable Income		10,165,848
Federal Corporate Income Tax Rate		21.00%
Income Tax Expense		2,134,828
Amortization of Excess ADIT	Schedule C-4	(420,839)
Net Income Tax Expense		1,713,989

WEST TEXAS GAS UTILITY, LLC
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Schedule G
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OTHER GAS INCOME BY MONTH (a)

Acct. No.	Description	2023												Total
		January	February	March	April	May	June	July	August	September	October	November	December	
488.0	Service Charges	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	86,100
488.0	Connection Fees	15,200	18,222	20,475	21,990	17,250	11,640	12,050	16,360	18,314	24,190	17,915	15,930	209,536
488.0	Meter Repaid -- Labor	-	-	-	-	-	-	-	-	-	-	-	661,907	661,907
488.0	Sales -- Regulators, etc.	-	166	-	-	33,925	175	35	2,960	30,057	44	36,502	38,226	142,090
488.0	Returned Check Fees	1,100	1,450	1,350	1,175	175	1,000	1,200	650	1,050	1,275	1,225	1,825	13,475
488.0	Miscellaneous Tariff Fees	820	790	1,620	790	850	3,260	680	1,220	610	610	830	580	12,660
488.0	Collection Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
492.0	Drip and Condensate Sale	27,760	25,343	22,238	2,793	4,515	3,514	4,196	3,826	24,699	-	-	(55,324)	63,560
495.0	Other Income	32,020	31,476	31,650	2,140	2,214	2,001	2,238	-	-	-	-	-	103,738
495.0	Purchase Meters	-	-	-	-	-	-	-	-	-	-	-	-	-

(a) WTG books and records.

WEST TEXAS GAS UTILITY, LLC
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OTHER GAS INCOME

Acct. No.	Description	Test Year WTG Total (a)	Oklahoma		Texas	Adjustments	Ref.	Adjusted Texas
			Direct (b)	Allocated (c)				
488.0	Service Charges	86,100		(14,051)	72,049	-		72,049
488.0	Connection Fees	209,536	(20,779)	-	188,757	-		188,757
488.0	Meter Repairs -- Labor	661,907		(108,019)	553,888	-		553,888
488.0	Sales -- Regulators, etc.	142,090	(3)	(23,188)	118,899	-		118,899
488.0	Returned Check Fees	13,475	(1,518)	-	11,957	-		11,957
488.0	Miscellaneous Tariff Fees	12,660	(116)	-	12,544	-		12,544
488.0	Collection Fees	-	(1)	-	(1)	-		(1)
		-			-	-		
492.0	Drip and Condensate Sales	63,560	(12,866)	(8,273)	42,420	-		42,420
		-			-	-		
495.0	Other Income	103,738	-	(16,929)	86,809	-		86,809
495.0	Purchase Meters	-	-	-	-	-		-
	Totals	1,293,066	(35,282)	(170,460)	1,087,324			
	Other Gas Income							1,087,324

(a) Schedule G.

(b) WTG books and records (detail is contained in electronic workpapers provided separately).

(c) Allocated using Average Number of Customers Allocation Factor from Schedule B-4 of 16.32%

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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PAYROLL SUMMARY

WTG Direct Expense

Period	Regular Payroll	Overtime Pay	Holiday Pay	On Call Pay	PTO Pay	Total WTG Payroll	Number of Employees
Jan 2020- Dec 2020	N/A	N/A	N/A		N/A	6,801,295	N/A
Jan 2021- Dec 2021	N/A	N/A	N/A		N/A	7,489,540	N/A
Jan 2022- Dec 2022	N/A	N/A	N/A		N/A	7,784,222	150
Jan-23	455,549	42,318	52,887	372	48,943	600,069	134
Feb-23	514,920	71,783	27,377	423	22,950	637,453	133
Mar-23	759,085	124,404	26,770	379	41,193	951,831	134
Apr-23	500,587	72,430	26,436	115	30,689	630,256	136
May-23	518,777	84,807	-	287	27,773	631,645	134
Jun-23	495,035	72,229	26,953	194	35,524	629,934	133
Jul-23	499,268	93,609	26,817	91	42,352	662,137	134
Aug-23	770,895	133,806	-	323	61,354	966,379	134
Sep-23	505,930	74,568	27,338	97	34,094	642,027	135
Oct-23	518,112	92,009	-	177	37,243	647,541	135
Nov-23	515,507	91,329	-	162	39,938	646,935	137
Dec-23	456,475	62,671	54,440	275	50,628	624,489	136
Total	6,510,140	1,015,964	269,017	2,894	472,681	8,270,696	135

WTG Allocated Expense through WTGDS

Period	Regular Payroll	Overtime Pay	Holiday Pay	On Call Pay	PTO Pay	Total WTG Payroll	Number of Employees
Jan 2020- Dec 2020	N/A	N/A	N/A	N/A	N/A	1,238,849	N/A
Jan 2021- Dec 2021	N/A	N/A	N/A	N/A	N/A	1,322,933	N/A
Jan 2022- Dec 2022	N/A	N/A	N/A	N/A	N/A	1,109,243	N/A
Jan-23	62,239	4	N/A	N/A	N/A	62,243.4	9
Feb-23	62,895	1,097	N/A	N/A	N/A	63,991.5	8
Mar-23	97,188	1,660	N/A	N/A	N/A	98,847.6	8
Apr-23	66,207	32	N/A	N/A	N/A	66,238.4	8
May-23	65,613	1,053	N/A	N/A	N/A	66,666.6	8
Jun-23	66,001	861	N/A	N/A	N/A	66,862.1	8
Jul-23	65,953	616	N/A	N/A	N/A	66,569.6	8
Aug-23	104,509	1,874	N/A	N/A	N/A	106,383.7	11
Sep-23	66,142	1,039	N/A	N/A	N/A	67,180.5	12
Oct-23	69,344	917	N/A	N/A	N/A	70,261.8	12
Nov-23	69,219	658	N/A	N/A	N/A	69,877.0	12
Dec-23	69,561	322	N/A	N/A	N/A	69,882.3	12
Total	864,871	10,134	N/A	N/A	N/A	875,004.5	10

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PAYROLL ANALYSIS

Period	Total WTG Payroll	Total Expensed	Total Capitalized	Charged to Clearing Accounts
Jan 2020- Dec 2020	6,351,681	8,040,144	(1,688,462)	-
Jan 2021- Dec 2021	7,696,602	8,812,472	(1,115,870)	
Jan 2022- Dec 2022	7,432,162	8,893,465	(1,461,302)	
Jan-23	662,313	662,313	-	
Feb-23	701,445	701,445	-	
Mar-23	1,050,679	1,050,679	-	
Apr-23	696,495	696,495	-	
May-23	698,311	698,311	-	
Jun-23	696,796	696,796	-	
Jul-23	728,706	728,706	-	
Aug-23	1,072,762	1,072,762	-	
Sep-23	709,208	709,208	-	
Oct-23	717,803	717,803	-	
Nov-23	716,812	716,812	-	
Dec-23	(536,004)	694,371	(1,230,375)	
Total	7,915,325	9,145,700	(1,230,375)	

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BAD DEBTS

West Texas Gas subscribes to the following procedures for the write-off of bad debts:

Efforts to collect past due accounts are first made by the local district office and credit manager for West Texas Gas. If internal efforts to collect the account are unsuccessful, it is then turned over for collection to an outside collection agency or an attorney. If those efforts are unsuccessful, then based on the recommendation of the credit manager or responsible attorney, the account balance is written off to the reserve for bad debt account.

West Texas Gas records a monthly accrual to its Reserve for Bad Debt account using the following method:

During the period January 2023 - December 2023:
 Current Month NG Sales Revenue X .125% = Reserve Accrual

Period	Reserve Balance at Beginning of Month	Bad Debt Monthly Accrual	Payments Collected on Bad Debt Accounts	Amounts Written Off	Reserve Balance at End of Month
Jan 2020- Dec 2020	1,899,156	124,885	1,550	(141,442)	1,884,148
Jan 2021- Dec 2021	1,884,148	196,292	2,862	-	2,083,302
Jan 2022- Dec 2022	2,083,302	343,111	2,712	(82,895)	2,346,230
Jan-23	2,346,230	20,875	433	-	2,367,538
Feb-23	2,367,538	13,820	523	-	2,381,881
Mar-23	2,381,881	16,046	481	-	2,398,408
Apr-23	2,398,408	16,293	95	-	2,414,795
May-23	2,414,795	13,034	89	-	2,427,918
Jun-23	2,427,918	8,956	107	-	2,436,981
Jul-23	2,436,981	17,800	428	-	2,455,209
Aug-23	2,455,209	23,506		-	2,478,715
Sep-23	2,478,715	16,814	16	-	2,495,545
Oct-23	2,495,545	11,853	542	-	2,507,940
Nov-23	2,507,940	11,174	399	-	2,519,514
Dec-23	2,519,514	10,441	147	(1,260,310)	1,269,792
Total		119,027	5,130	(123,396)	

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ADVERTISING EXPENSES

Period	FERC Acct	Region									Total
		Corp R-1	R-10	R-20	R-30	R-40	R-50	R-60	R-70	R-80	
Jan-23	913.0	-	-	-	-	-	79	800	-	-	879
Feb-23	913.0	-	-	-	-	-	79	-	-	6,305	6,384
Mar-23	913.0	-	-	762	-	60	-	-	-	860	1,682
Apr-23	913.0	-	-	685	-	-	-	1,380	130	-	2,195
May-23	913.0	-	-	1,262	-	-	-	281	-	-	1,543
Jun-23	913.0	-	-	-	-	125	79	954	-	938	2,096
Jul-23	913.0	-	-	5	-	-	79	-	-	-	84
Aug-23	913.0	-	-	-	23	47	79	447	-	629	1,225
Sep-23	913.0	-	150	-	-	63	-	1,574	-	-	1,787
Oct-23	913.0	-	799	467	-	-	79	799	-	-	2,144
Nov-23	913.0	-	-	-	-	-	-	-	-	-	-
Dec-23	913.0	-	799	-	75	140	150	-	210	-	1,374
Total		-	1,748	3,181	98	435	624	6,234	340	8,732	21,392

DONATIONS AND CONTRIBUTIONS

Payee	FERC Acct.	Region									Total	Purpose
		Corp R-1	R-10	R-20	R-30	R-40	R-50	R-60	R-70	R-80		
S.M.A.R.T.	880.0	-	-	-	-	-	-	-	50	-	50	Donation/Sponsorship
DALHART FIRE DEPARTMENT	880.0	-	-	-	-	-	-	200	-	-	200	Donation/Sponsorship
DHS YEARBOOK	880.0	-	-	-	-	-	-	200	-	-	200	Donation/Sponsorship
DALHART PROJECT GRADUATION	880.0	-	-	-	-	-	-	250	-	-	250	Donation/Sponsorship
LUBBOCK LEMONADE DAY	880.0	-	-	500	-	-	-	-	-	-	500	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	-	-	1,750	1,750	Donation/Sponsorship
HIGGINBOTHAM BUILDING CENTER	880.0	-	-	-	368	-	-	-	-	-	368	Donation/Sponsorship
ETA UPSILON SORORITY	880.0	-	-	-	-	-	-	100	-	-	100	Donation/Sponsorship
TEXAS GAS ASSOCIATION	880.0	-	350	-	-	-	-	-	-	-	350	Donation/Sponsorship
AARON K BOLES	880.0	-	-	251	-	-	-	-	-	-	251	Donation/Sponsorship
CANADIAN ROTARY CLUB	880.0	-	-	-	-	60	-	-	-	-	60	Donation/Sponsorship
BI-COUNTY FIRST RESPONDERS	880.0	-	-	-	-	-	-	320	-	-	320	Donation/Sponsorship
USA LLC	880.0	-	799	-	-	-	-	-	-	-	799	Donation/Sponsorship
JUNCTION ROTARY CLUB	880.0	-	-	-	95	-	-	-	-	-	95	Donation/Sponsorship
THE DALHART TEXAN	880.0	-	-	-	-	400	-	-	-	-	400	Donation/Sponsorship
KIMBLE CO. CHAMBER OF COMMERCE	880.0	-	-	-	125	-	-	-	-	-	125	Donation/Sponsorship
WHEELER LIONS CLUB	880.0	-	-	-	-	35	-	-	-	-	35	Donation/Sponsorship
FIVE RIVERS-CIMARRON FEEDER'S	880.0	-	-	-	-	-	-	650	-	-	650	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	500	-	-	500	Donation/Sponsorship
XIT RODEO AND REUNION	880.0	-	-	-	-	-	-	6,000	-	-	6,000	Donation/Sponsorship
ONSHORE QUALITY CONTROL	880.0	-	500	-	-	-	-	-	-	-	500	Donation/Sponsorship
OUR LADY OF FATIMA CATHOLIC	880.0	-	500	-	-	-	-	-	-	-	500	Donation/Sponsorship
SHAMROCK ROTARY CLUB	880.0	-	-	-	-	30	-	-	-	-	30	Donation/Sponsorship
DALHART GOLDEN WOLVES BAND	880.0	-	-	-	-	-	-	250	-	-	250	Donation/Sponsorship
ONSHORE QUALITY CONTROL	880.0	-	(500)	-	-	-	-	-	-	-	(500)	Donation/Sponsorship
MOORE COUNTY CHAMBER OF	880.0	-	-	-	-	-	-	250	-	-	250	Donation/Sponsorship
KERMIT ROTARY CLUB	880.0	-	75	-	-	-	-	-	-	-	75	Donation/Sponsorship
USA LLC	880.0	-	799	-	-	-	-	-	-	-	799	Donation/Sponsorship
STRIKE OUT CANCER	880.0	-	-	-	-	-	-	300	-	-	300	Donation/Sponsorship
CANADIAN RIVER BEACH CLUB, INC	880.0	-	-	-	-	5,000	-	-	-	-	5,000	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	1,525	-	-	1,525	Donation/Sponsorship
CANADIAN RIVER BEACH CLUB, INC	880.0	-	-	-	-	5,000	-	-	-	-	5,000	Donation/Sponsorship
MINDY LEE	880.0	-	-	-	-	-	-	-	200	-	200	Donation/Sponsorship
STEPHANIE FOUST	880.0	-	-	-	-	-	-	350	-	-	350	Donation/Sponsorship
DEVINE YOUTH SPORTS INC	880.0	-	-	-	-	-	-	-	-	250	250	Donation/Sponsorship
GROOM LIONS CLUB	880.0	-	-	-	-	-	25	-	-	-	25	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	(5,000)	-	-	-	-	(5,000)	Donation/Sponsorship
ARMSTRONG COUNTY JR LIVESTOCK	880.0	-	-	-	-	-	500	-	-	-	500	Donation/Sponsorship
CANYON INDEPENDENT SCHOOL	880.0	-	-	-	-	-	500	-	-	-	500	Donation/Sponsorship
RICKY RICE	880.0	-	-	-	-	-	-	375	-	-	375	Donation/Sponsorship
SHAMROCK FIRE DEPARTMENT	880.0	-	-	-	-	250	-	-	-	-	250	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	318	-	-	318	Donation/Sponsorship
SHAMROCK JR. LIVESTOCK	880.0	-	-	-	-	250	-	-	-	-	250	Donation/Sponsorship
HEMPHILL COUNTY LIVESTOCK	880.0	-	-	-	-	250	-	-	-	-	250	Donation/Sponsorship
WEST TEXAS A&M UNIVERSITY	880.0	-	-	-	-	-	875	-	-	-	875	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	495	-	-	495	Donation/Sponsorship
NATURAL GAS SOCIETY OF THE P.B	930.2	1,000	-	-	-	-	-	-	-	-	1,000	Donation/Sponsorship
MIDLAND RAPE CRISIS CENTER INC	930.2	3,500	-	-	-	-	-	-	-	-	3,500	Donation/Sponsorship
CENTERS FOR CHILDREN &	930.2	5,000	-	-	-	-	-	-	-	-	5,000	Donation/Sponsorship
TEXAS COTTON GINNERS'	930.2	850	-	-	-	-	-	-	-	-	850	Donation/Sponsorship
TEXAS COTTON GINNERS'	930.2	850	-	-	-	-	-	-	-	-	850	Donation/Sponsorship
ROTARY CLUB OF MIDLAND	930.2	500	-	-	-	-	-	-	-	-	500	Donation/Sponsorship
TOTAL		11,700	2,523	751	588	6,275	1,900	12,083	250	2,000	38,070	

WEST TEXAS GAS UTILITY, LLC
 Test Period Ending December 31, 2023

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LOBBYING EXPENSES

Month	Payee	Account Charged	Amount	Purpose
Jan-23	Phil Gamble Attorney At Law	923.0	814	Professional Services
Feb-23	Phil Gamble Attorney At Law	923.0	822	Professional Services
Mar-23	Phil Gamble Attorney At Law	923.0	814	Professional Services
Apr-23	Phil Gamble Attorney At Law	923.0	814	Professional Services
May-23	Phil Gamble Attorney At Law	923.0	814	Professional Services
Jun-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Jul-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Aug-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Sep-23	Phil Gamble Attorney At Law	923.0	883	Professional Services
Oct-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Nov-23	Phil Gamble Attorney At Law	923.0	883	Professional Services
Dec-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Total			10,219	

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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PENALTIES AND FINES

<u>Month</u>	<u>Payee</u>	<u>Account Charged</u>	<u>Amount</u>	<u>Purpose</u>
Jan-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 077804
May-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 079597
Jun-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 079923
Jul-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 080575
Jul-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 080284
Jul-23	RAILROAD COMMISSION OF TX	921.0	3,500	DOC NO 080665
Jul-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 081223
Aug-23	COMPTROLLER OF PUBLIC ACCOUNTS	921.0	367	EFT PENALTY
Aug-23	RAILROAD COMMISSION OF TX	921.0	2,750	DOC NO 080284
Dec-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 083953
Total			24,117	

OUTSIDE SERVICES CHARGED TO A&G ACCOUNTS

Month	Payee	Account Charged	Amount	Purpose
Jan-24	ZDSCADA LP	923.0	53	Scada Hosting Services
Jan-24	ASSOCIATED SYSTEMS	923.0	2,264	Billing Software Support
Jan-24	JOE COFFMAN	923.0	6,374	Consulting
Jan-24	COST CONTAINMENT ADVISORS, INC	923.0	33,976	Consulting
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,168	Contract Labor
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,140	Contract Labor
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Jan-24	WTG DOWNSTREAM SERVICES LLC	923.0	66,595	Overhead
Jan-24	RCP INC	923.0	905	Regulatory Compliance
Jan-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	50	Safety Services
Jan-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,142	Safety Services
Jan-24	OLEN DOUGLASS	923.0	(58)	Contract Labor
Feb-24	WHITLEY PENN LLP	923.0	1,301	Accounting
Feb-24	ASSOCIATED SYSTEMS	923.0	2,553	Billing Software Support
Feb-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Feb-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Feb-24	WTG DOWNSTREAM SERVICES LLC	923.0	46,328	Overhead
Feb-24	RCP INC	923.0	505	Regulatory Compliance
Feb-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,165	Safety Services
Mar-24	WHITLEY PENN LLP	923.0	3,014	Accounting
Mar-24	ALWAYS ANSWER	923.0	2,849	Answering Service
Mar-24	ASSOCIATED SYSTEMS	923.0	4,368	Billing Software Support
Mar-24	WTG DOWNSTREAM SERVICES LLC	923.0	72,999	Overhead
Mar-24	RCP INC	923.0	400	Regulatory Compliance
Mar-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,690	Safety Services
Apr-24	WHITLEY PENN LLP	923.0	56,963	Accounting
Apr-24	ALWAYS ANSWER	923.0	2,848	Answering Service
Apr-24	ASSOCIATED SYSTEMS	923.0	8,823	Billing Software Support
Apr-24	JOE COFFMAN	923.0	6,150	Consulting
Apr-24	ESRI, INC.	923.0	56,983	Mapping Software Support
Apr-24	WTG DOWNSTREAM SERVICES LLC	923.0	50,617	Overhead
Apr-24	RCP INC	923.0	400	Regulatory Compliance
Apr-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,399	Safety Services
May-24	ASSOCIATED SYSTEMS	923.0	6,224	Billing Software Support
May-24	JOE COFFMAN	923.0	5,557	Consulting
May-24	WTG DOWNSTREAM SERVICES LLC	923.0	67,129	Overhead
May-24	U S PAYMENTS LLC	923.0	1,547	Payment Software Support
May-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,418	Safety Services
May-24	ENTECH CONSULTING CORP	923.0	35,817	Consulting
May-24	ENERGY SERVICES GROUP	923.0	1,066	FERC Filing Support
Jun-24	U S PAYMENTS LLC	923.0	1,523	Payment Software Support
Jun-24	ALWAYS ANSWER	923.0	3,322	Answering Service
Jun-24	ASSOCIATED SYSTEMS	923.0	2,017	Billing Software Support
Jun-24	JOE COFFMAN	923.0	4,275	Consulting
Jun-24	DONALD G. BLAND	923.0	1,374	Contract Labor
Jun-24	WTG DOWNSTREAM SERVICES LLC	923.0	203,280	Overhead
Jun-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,228	Safety Services
Jul-24	WHITLEY PENN LLP	923.0	18,383	Accounting
Jul-24	ALWAYS ANSWER	923.0	2,406	Answering Service
Jul-24	ASSOCIATED SYSTEMS	923.0	4,657	Billing Software Support
Jul-24	JOE COFFMAN	923.0	6,675	Consulting
Jul-24	WTG DOWNSTREAM SERVICES LLC	923.0	90,732	Overhead
Jul-24	U S PAYMENTS LLC	923.0	1,368	Payment Software Support
Jul-24	U S PAYMENTS LLC	923.0	1,495	Payment Software Support
Jul-24	RCP INC	923.0	820	Regulatory Compliance
Jul-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,230	Safety Services
Jul-24	HI PLAINS CANVAS PRODUCTS INC.	923.0	490	Contract Labor
Jul-24	ENERGY SERVICES GROUP	923.0	3,998	FERC Filing Support
Jul-24	AERIANA ROJAS	923.0	525	Contract Labor
Aug-24	WHITLEY PENN LLP	923.0	16,034	Accounting
Aug-24	ASSOCIATED SYSTEMS	923.0	5,399	Billing Software Support
Aug-24	JOE COFFMAN	923.0	5,100	Consulting
Aug-24	WTG DOWNSTREAM SERVICES LLC	923.0	70,304	Overhead
Aug-24	RCP INC	923.0	610	Regulatory Compliance
Aug-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,567	Safety Services
Aug-24	PARADIGM ALLIANCE INC	923.0	15,054	Public Awareness Mailing Service
Aug-24	ALTAMIRA-US, LLC	923.0	40,396	ROW Assessment
Sep-24	WHITLEY PENN LLP	923.0	2,750	Accounting
Sep-24	ASSOCIATED SYSTEMS	923.0	8,740	Billing Software Support
Sep-24	JOE COFFMAN	923.0	6,450	Consulting
Sep-24	WILLIS PERMIAN MOVERS INC	923.0	100	Contract Labor
Sep-24	WILLIS PERMIAN MOVERS INC	923.0	581	Contract Labor
Sep-24	WTG DOWNSTREAM SERVICES LLC	923.0	45,194	Overhead
Sep-24	RCP INC	923.0	500	Regulatory Compliance
Sep-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,397	Safety Services
Oct-24	WHITLEY PENN LLP	923.0	1,410	Accounting
Oct-24	OKLAHOMA ONE-CALL SYSTEM INC	923.0	5,404	Answering Service
Oct-24	ASSOCIATED SYSTEMS	923.0	5,399	Billing Software Support
Oct-24	JOE COFFMAN	923.0	6,314	Consulting
Oct-24	WTG DOWNSTREAM SERVICES LLC	923.0	109,894	Overhead
Oct-24	RCP INC	923.0	715	Regulatory Compliance
Oct-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	3	Safety Services
Oct-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,317	Safety Services
Nov-24	WHITLEY PENN LLP	923.0	12,627	Accounting
Nov-24	ALWAYS ANSWER	923.0	3,043	Answering Service
Nov-24	ENTECH CONSULTING CORP	923.0	13,016	Consulting
Nov-24	WTG DOWNSTREAM SERVICES LLC	923.0	79,616	Overhead
Nov-24	RCP INC	923.0	400	Regulatory Compliance
Dec-24	WHITLEY PENN LLP	923.0	4,939	Accounting
Dec-24	ALWAYS ANSWER	923.0	3,000	Answering Service
Dec-24	ASSOCIATED SYSTEMS	923.0	2,924	Billing Software Support
Dec-24	AVATAR SYSTEMS INC	923.0	1,786	Billing Software Support
Dec-24	ASSOCIATED SYSTEMS	923.0	2,842	Billing Software Support
Dec-24	I.C. SYSTEMS, INC.	923.0	271	Collections
Dec-24	ENTECH CONSULTING CORP	923.0	55,000	Consulting
Dec-24	JOE COFFMAN	923.0	14,550	Consulting
Dec-24	WTG DOWNSTREAM SERVICES LLC	923.0	64,727	Overhead
Dec-24	RCP INC	923.0	400	Regulatory Compliance
Dec-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,034	Safety Services
Dec-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	1,636	Safety Services
Total			1,534,259	

LEGAL EXPENSE DETAIL

Line	Payee	FERC Acct.	Region									Total
			Corp R-1	R-10	R-20	R-30	R-40	R-50	R-60	R-70	R-80	
1	TODD, BARRON, THOMASON,	923.0	(140)	-	-	-	-	-	-	-	-	(140)
2	ROSS MOLINA OLIVEROS PC	923.0	163	-	-	-	-	-	-	-	-	163
3	ROSS MOLINA OLIVEROS PC	923.0	163	-	-	-	-	-	-	-	-	163
4	TODD, BARRON, THOMASON,	923.0	38	-	-	-	-	-	-	-	-	38
5	COFFIN RENNER LLP	923.0	942	-	-	-	-	-	-	-	-	942
6	COFFIN RENNER LLP	923.0	6,005	-	-	-	-	-	-	-	-	6,005
7	JOHN & HENGERER LLP	923.0	8,700	-	-	-	-	-	-	-	-	8,700
8	COFFIN RENNER LLP	923.0	4,617	-	-	-	-	-	-	-	-	4,617
9	TODD, BARRON, THOMASON,	923.0	341	-	-	-	-	-	-	-	-	341
10	SMITH CLARK PLLC	923.0	6,111	-	-	-	-	-	-	-	-	6,111
11	COFFIN RENNER LLP	923.0	979	-	-	-	-	-	-	-	-	979
12	COFFIN RENNER LLP	923.0	6,140	-	-	-	-	-	-	-	-	6,140
13	SIDLEY AUSTIN LLP	923.0	7,251	-	-	-	-	-	-	-	-	7,251
14	TODD, BARRON, THOMASON,	923.0	36	-	-	-	-	-	-	-	-	36
15	TODD, BARRON, THOMASON,	923.0	591	-	-	-	-	-	-	-	-	591
16	SMITH CLARK PLLC	923.0	8,056	-	-	-	-	-	-	-	-	8,056
17	TODD, BARRON, THOMASON,	923.0	97	-	-	-	-	-	-	-	-	97
18	SMITH CLARK PLLC	923.0	15,372	-	-	-	-	-	-	-	-	15,372
19	COFFIN RENNER LLP	923.0	(4,617)	-	-	-	-	-	-	-	-	(4,617)
20	JOHN & HENGERER LLP	923.0	8,156	-	-	-	-	-	-	-	-	8,156
21	COFFIN RENNER LLP	923.0	4,108	-	-	-	-	-	-	-	-	4,108
22	TODD, BARRON, THOMASON,	923.0	51	-	-	-	-	-	-	-	-	51
23	TODD, BARRON, THOMASON,	923.0	33	-	-	-	-	-	-	-	-	33
24	SMITH CLARK PLLC	923.0	(3,297)	-	-	-	-	-	-	-	-	(3,297)
25	JOHN & HENGERER LLP	923.0	1,813	-	-	-	-	-	-	-	-	1,813
26	TODD, BARRON, THOMASON,	923.0	330	-	-	-	-	-	-	-	-	330
27	TODD, BARRON, THOMASON,	923.0	228	-	-	-	-	-	-	-	-	228
28	JOHN & HENGERER LLP	923.0	544	-	-	-	-	-	-	-	-	544
29	COFFIN RENNER LLP	923.0	206	-	-	-	-	-	-	-	-	206
30	COFFIN RENNER LLP	923.0	3,875	-	-	-	-	-	-	-	-	3,875
31	SMITH CLARK PLLC	923.0	6,814	-	-	-	-	-	-	-	-	6,814
32	COFFIN RENNER LLP	923.0	1,817	-	-	-	-	-	-	-	-	1,817
33	COFFIN RENNER LLP	923.0	11,809	-	-	-	-	-	-	-	-	11,809
34	G. WILLIAM FOWLER, P. C.	923.0	748	-	-	-	-	-	-	-	-	748
35	ROSS MOLINA OLIVEROS PC	923.0	390	-	-	-	-	-	-	-	-	390
36	COFFIN RENNER LLP	923.0	2,661	-	-	-	-	-	-	-	-	2,661
37	COFFIN RENNER LLP	923.0	3,438	-	-	-	-	-	-	-	-	3,438
38	COFFIN RENNER LLP	923.0	875	-	-	-	-	-	-	-	-	875
39	G. WILLIAM FOWLER, P. C.	923.0	417	-	-	-	-	-	-	-	-	417
40	SMITH CLARK PLLC	923.0	6,688	-	-	-	-	-	-	-	-	6,688
41	COTTON BLEDSOE TIGHE & DAWSON	923.0	350	-	-	-	-	-	-	-	-	350
42	JOHN & HENGERER LLP	923.0	1,631	-	-	-	-	-	-	-	-	1,631
43	COFFIN RENNER LLP	923.0	1,188	-	-	-	-	-	-	-	-	1,188
44	COFFIN RENNER LLP	923.0	2,476	-	-	-	-	-	-	-	-	2,476
45	DAVIS, GERALD & CREMER	923.0	1,330	-	-	-	-	-	-	-	-	1,330
46	COFFIN RENNER LLP	923.0	2,005	-	-	-	-	-	-	-	-	2,005
47	COFFIN RENNER LLP	923.0	1,500	-	-	-	-	-	-	-	-	1,500
48	DAVIS, GERALD & CREMER	923.0	1,376	-	-	-	-	-	-	-	-	1,376
49	SMITH CLARK PLLC	923.0	4,362	-	-	-	-	-	-	-	-	4,362
50	COFFIN RENNER LLP	874.0		1,688	-	-	-	-	-	-	-	1,688
51	Total		128,759	1,688	-	-	-	-	-	-	-	130,447

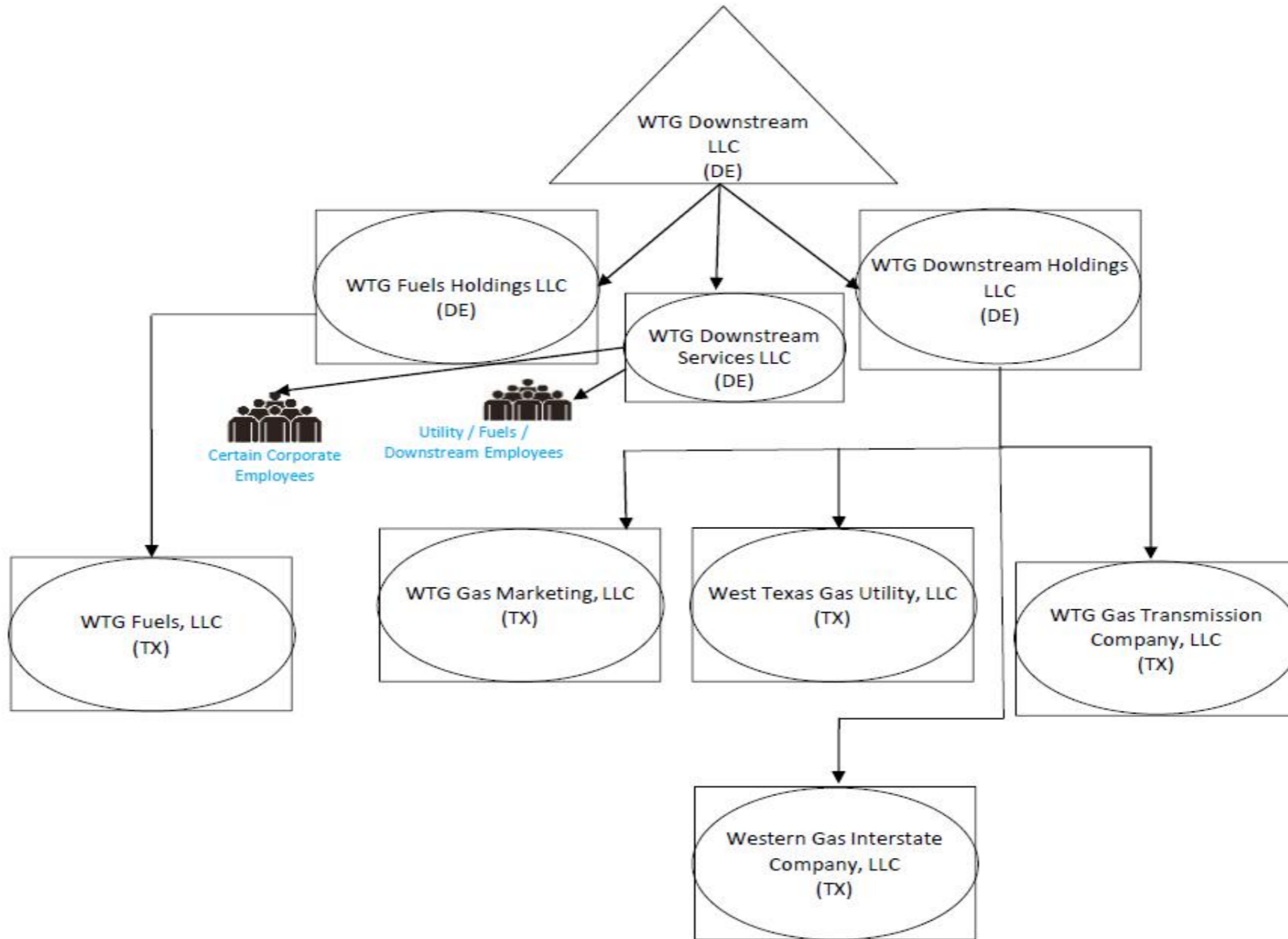
WEST TEXAS GAS UTILITY, LLC
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LOST AND UNACCOUNTED-FOR GAS

Period	Total Texas Receipts (Mcf)	Total Texas Deliveries (Mcf)	Distribution Gain / (Loss)	Distribution LUFG Percent
Jan 2020 - Dec 2020	28,516,710	27,270,221	(1,246,489)	-4.37%
Jan 2021 - Dec 2021	28,182,783	27,553,940	(628,843)	-2.23%
Jan 2022 - Dec 2022	31,262,353	30,296,943	(965,410)	-3.09%
Jan 2023 - Dec 2023	28,337,712	27,359,457	(978,255)	-3.45%

ORGANIZATIONAL CHART



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CHARGES BY AFFILIATES TO WTG

Affiliate	Nature of Charge	Amount (a) (b)	FERC #	Basis
WTG Gas Marketing, LLC	Gas Purchases	60,787,627	803.0	Cost Per Gas Purchase Contract with Affiliate
Total Gas Purchases		60,787,627		
Western Gas Interstate Company	Gas Transport	441,354	858.0	Cost per Gas Contract with Affiliate
Total Gas Transport		441,354		
WTG Fuels, Inc.	Auto Oil & Gas	358,393	930.2	Street price
WTG Fuels, Inc.	Auto Other	342	880.0	At cost
WTG Fuels, Inc.	Auto Maint	1,458	894.0	At cost
Total Auto Oil & Gas		360,193		
WTG Fuels, Inc.	Propane	2,488	880.0	At cost
Total Propane		2,488		
WTG Downstream Services, LLC	Overhead Burden	967,417	923.0	As calculated in Corp Allocation Formula
Total Overhead Burden		967,417		
Total		62,559,079		

(a) Gas Purchases and Gas Transport charges by affiliates excluded from calculation of base rates; all other charges by affiliates to WTG included.

(b) No charges by affiliates were capitalized during the test year.

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CHARGES BY AFFILIATES TO OTHERS

Line	Affiliate (Recording Income)	Nature of Charge	Affiliate (Recording Expense)	Amount
1	WTG Downstream Services LLC	Overhead Burden	WTG Fuels LLC	694,516
2	WTG Downstream Services LLC	Overhead Burden	WTG Gas Marketing LLC	236,022
3	WTG Downstream Services LLC	Overhead Burden	Western Gas Interstate Co LLC	60,241
4	WTG Downstream Services LLC	Overhead Burden	WTG South Permian - Irion County	158,770
5	WTG Downstream Services LLC	Overhead Burden	WTG Gas Processing LLC	273,854
6	WTG Downstream Services LLC	Overhead Burden	Fuller Gas Plant	30,220
7	WTG Downstream Services LLC	Overhead Burden	East Vealmoor Plant	1,645,567
8	WTG Downstream Services LLC	Overhead Burden	WTG North Permian Midstream LLC	2,917,286
9	WTG Downstream Services LLC	Overhead Burden	WTG Fuels LLC	10,527
10	WTG Downstream Services LLC	Overhead Burden	WTG Gas Transmission Company LLC	284,553
11	WTG Downstream Services LLC	Overhead Burden	WTG Jameson L.P.	578,325
12	WTG Downstream Services LLC	Overhead Burden	Ledco LLC	20,646
13	WTG Downstream Services LLC	Overhead Burden	WTG Hugoton L.P.	104,754
14	WTG Downstream Services LLC	Overhead Burden	WTG NGL Marketing LLC	100,431
15	WTG Downstream Services LLC	Overhead Burden	WTG Gas Gathering Company LLC	167,206
16	WTG Downstream Services LLC	Overhead Burden	WTG NGL Pipeline Company LLC	57,882
17	WTG Downstream Services LLC	Overhead Burden	WTG Midstream Marketing	42,597
18	WTG Downstream Services LLC	Overhead Burden	Low Country Power	74,390
19	WTG Downstream Services LLC	Overhead Burden	WTG South Permian Midstream LLC	2,727,297
20	WTG North Permian Midstream LLC	Gas Plant Product	WTG NGL Marketing LLC	6,865,918
21	WTG NGL Pipeline Company LLC	Gas Transportation	WTG Gas Processing Super System	1,786,109
22	WTG NGL Pipeline Company LLC	Gas Transportation	WTG NGL Marketing LLC	1,580,299
23	WTG NGL Pipeline Company LLC	Gas Transportation	WTG North Permian Midstream	204,601
24	WTG Midstream Marketing LLC	Natural Gas Purchases	WTG Gas Marketing LLC	74,003,473
25	WTG Midstream Marketing LLC	Natural Gas Purchases	WTG Gas Processing Super System	23,814,436
26	WTG Gas Transmission Company LLC	Gas Transportation	WTG Gas Marketing LLC	5,145,979
27	WTG Gas Transmission Company LLC	Gas Transportation	WTG Midstream Marketing	15,364,768
28	WTG Gas Processing LLC	Gas Transportation	Fuller Gas Plant	12,299
29	WTG Gas Processing LLC	Gas Plant Product	WTG NGL Marketing LLC	28,000,517
30	WTG Gas Processing LLC-Supersystem	Gas Transportation	WTG NGL Pipeline Company LLC	154,326
31	WTG Gas Processing LLC-Supersystem	Gas Plant Product	WTG NGL Marketing LLC	738,174,530
32	WTG Gas Processing LLC-Supersystem	Gas Plant Product	Low Country Power	4,541,681
33	WTG Gas Processing LLC-Supersystem	Gas Plant Product	WTG Gas Marketing LLC	564,149
34	WTG Gas Processing LLC-Supersystem	Gas Plant Product	WTG Midstream Marketing	360,188,268
35	WTG Gas Marketing LLC	Natural Gas Purchases	Fuller Gas Plant	6,226
36	WTG Gas Marketing LLC	Natural Gas Purchases	WTG Gas Processing Super System	16,307,341
37	WTG Gas Marketing LLC	Natural Gas Purchases	WTG Jameson L.P.	170,118
38	WTG Gas Marketing LLC	Natural Gas Purchases	WTG Midstream Marketing	7,014
39	WTG Gas Marketing LLC	Natural Gas Purchases	WTG South Permian Midstream LLC	1,382,242
40	WTG Gas Gathering Company LLC	Gas Transportation	WTG Gas Processing Super System	8,040,330
41	WTG Gas Gathering Company LLC	Gas Transportation	WTG South Permian - Irion County	147,460
42	WTG Gas Gathering Company LLC	Gas Transportation	WTG South Permian Midstream LLC	2,588
43	WTG Fuels LLC	Auto Oil & Gas	Western Gas Interstate Co LLC	20,578
44	WTG Fuels LLC	Auto Oil & Gas	WTG Gas Transmission Company	8,762
45	WTG Fuels LLC	Auto Oil & Gas	WTG Hugoton L.P.	43,124
46	WTG Fuels LLC	Auto Oil & Gas	WTG NGL Pipeline Company LLC	8,508
47	WTG Fuels LLC	Auto Oil & Gas	WTG North Permian Midstream	444,427
48	WTG Fuels LLC	Auto Oil & Gas	WTG South Permian - Irion County	35,278
49	WTG Fuels LLC	Auto Oil & Gas	East Vealmoor Plant	277,580
50	WTG Fuels LLC	Auto Oil & Gas	WTG Gas Transmission Company LLC	2,738
51	WTG Fuels LLC	Auto Oil & Gas	WTG Jameson L.P.	119,885
52	WTG Fuels LLC	Auto Oil & Gas	Ledco LLC	3,860
53	WTG Fuels LLC	Auto Oil & Gas	WTG Midstream Marketing LLC	710
54	WTG Fuels LLC	Auto Oil & Gas	WTG South Permian Midstream LLC	638,599
61	WTG Fuels LLC	Oils, Lubricants, Other Products	East Vealmoor Plant	18,914
62	WTG Fuels LLC	Oils, Lubricants, Other Products	WTG Jameson L.P.	231,853
63	WTG Fuels LLC	Oils, Lubricants, Other Products	WTG North Permian Midstream	196,375
64	WTG Fuels LLC	Oils, Lubricants, Other Products	WTG South Permian - Irion County	8,880
65	WTG Fuels LLC	Oils, Lubricants, Other Products	WTG South Permian Midstream LLC	404,210
66	Western Gas Interstate Co LLC	Gas Transportation	WTG Gas Marketing LLC	790,140
67	Low Country Power	Electricity	WTG North Permian Midstream	25,033,505
68	Total			1,324,937,683

WEST TEXAS GAS UTILITY, LLC
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COST OF SERVICE STUDY -- COST CLASSIFICATION

Description:	Texas	Jurisdictional	Non-	Classification	Joint		Jurisdictional Only		Non-Jurisdictional Only		
	Total				Joint	Only	Only	Factor	Customer	Capacity	Customer
Plant in Service											
301 Organization	57,872	57,872	-	-	Other Gas Plant	34,891	22,981	-	-	-	-
302 Franchises and Consents	200,000	200,000	-	-	Other Gas Plant	120,580	79,420	-	-	-	-
303 Intangible Plant	341,866	279,535	62,331	-	Other Gas Plant	168,532	111,004	37,317	25,014	-	-
332 Field Lines	3,047,811	3,045,801	-	2,010	Aggregate	1,822,996	1,222,804	-	-	1,203	807
334 Field M&R Station Equipment	100,000	100,000	-	-	Aggregate	59,853	40,147	-	-	-	-
365 Land and Rights-of-Way	5,379,123	5,379,123	-	-	Aggregate	3,219,555	2,159,569	-	-	-	-
366 Structures and Improvements	-	-	-	-	Aggregate	-	-	-	-	-	-
367 Mains	45,312,827	36,636,145	7,808,497	868,185	Pipe	21,862,767	14,773,378	4,659,752	3,148,745	518,093	350,092
368 Compressor Station Equipment	38,984	38,984	-	-	Aggregate	23,333	15,651	-	-	-	-
369 M&R Station Equipment	1,413,460	1,310,842	97,790	4,828	Meters	930,995	379,847	69,453	28,337	3,429	1,399
371 Other Equipment	224,148	211,222	9,926	3,001	Aggregate	126,422	84,800	5,941	3,985	1,796	1,205
376 Mains	167,899,665	86,066,057	75,673,412	6,160,195	Pipe	51,360,267	34,705,791	45,158,413	30,514,998	3,676,121	2,484,074
377 Compressors	358,216	358,216	-	-	Aggregate	214,402	143,814	-	-	-	-
378 M&R Station Equipment - General	7,692,969	6,086,442	1,350,381	256,145	Meters	4,322,754	1,763,688	959,077	391,304	181,921	74,224
387 Other Equipment	687,636	646,525	31,536	9,574	Other Gas Plant	389,789	256,736	18,880	12,656	5,752	3,822
389 Rights-of-Way	6,499,511	6,494,591	4,920	-	Other Gas Plant	3,915,583	2,579,008	2,946	1,974	-	-
390 Office Buildings	4,562,846	4,272,167	114,869	175,809	Other Gas Plant	2,575,685	1,696,481	68,771	46,098	105,629	70,181
391 Office Furniture and Equipment	272,377	233,840	31,375	7,163	Other Gas Plant	140,982	92,858	18,784	12,591	4,303	2,859
392 Transportation Equip	2,900,187	2,797,249	25,393	77,545	Other Gas Plant	1,686,459	1,110,790	15,203	10,191	46,590	30,955
394 Tools, Shop & Garage	1,162,584	1,097,954	21,572	43,059	Other Gas Plant	661,955	435,998	12,915	8,657	25,870	17,188
396 Power Operated Equipment	356,492	356,492	-	-	Other Gas Plant	214,929	141,563	-	-	-	-
397 Communication Equip	523,132	140,756	324,654	57,722	Other Gas Plant	84,861	55,894	194,367	130,287	34,680	23,042
398 Miscellaneous Equip	134,907	88,608	41,186	5,113	Other Gas Plant	53,422	35,186	24,657	16,528	3,072	2,041
Total Plant in Service	249,166,612	155,898,421	85,597,842	7,670,349		93,991,012	61,907,409	51,246,475	34,351,367	4,608,461	3,061,888
Accumulated Depreciation											
301 Organization	(57,872)	(57,872)	-	-	Other Gas Plant	(34,891)	(22,981)	-	-	-	-
302 Franchises and Consents	(200,000)	(200,000)	-	-	Other Gas Plant	(120,580)	(79,420)	-	-	-	-
303 Intangible Plant	(626,340)	(626,340)	-	-	Other Gas Plant	(377,620)	(248,720)	-	-	-	-
332 Field Lines	(3,395,407)	(3,394,990)	-	(417)	Aggregate	(2,031,996)	(1,362,994)	-	-	(250)	(167)
334 Field M&R Station Equipment	(50,485)	(50,485)	-	-	Aggregate	(30,217)	(20,268)	-	-	-	-
365 Land and Rights-of-Way	(612,078)	(612,078)	-	-	Aggregate	(366,346)	(245,732)	-	-	-	-
366 Structures and Improvements	-	-	-	-	Aggregate	-	-	-	-	-	-
367 Mains	(13,446,426)	(12,686,741)	(661,067)	(98,618)	Pipe	(7,570,864)	(5,115,877)	(394,494)	(266,573)	(58,851)	(39,767)
368 Compressor Station Equipment	(49,512)	(49,512)	-	-	Aggregate	(29,634)	(19,878)	-	-	-	-
369 M&R Station Equipment	(799,842)	(790,602)	(8,108)	(1,132)	Meters	(561,507)	(229,095)	(5,758)	(2,349)	(804)	(328)
371 Other Equipment	(210,395)	(204,380)	(4,811)	(1,204)	Aggregate	(122,327)	(82,053)	(2,880)	(1,932)	(721)	(483)
376 Mains	(41,183,364)	(34,326,151)	(6,542,474)	(314,739)	Pipe	(20,484,269)	(13,841,882)	(3,904,248)	(2,638,226)	(187,822)	(126,917)
377 Compressors	(390,060)	(390,060)	-	-	Aggregate	(233,462)	(156,598)	-	-	-	-
378 M&R Station Equipment - General	(4,936,538)	(4,815,728)	(75,534)	(45,277)	Meters	(3,420,259)	(1,395,469)	(53,646)	(21,888)	(32,157)	(13,120)
387 Other Equipment	(548,063)	(535,357)	(10,493)	(2,213)	Other Gas Plant	(322,766)	(212,591)	(6,282)	(4,211)	(1,330)	(884)
389 Rights-of-Way	(2,566,501)	(2,566,501)	-	-	Other Gas Plant	(1,547,341)	(1,019,160)	-	-	-	-
390 Office Buildings	(1,378,613)	(1,325,557)	(17,846)	(35,210)	Other Gas Plant	(799,177)	(526,380)	(10,684)	(7,162)	(21,155)	(14,055)
391 Office Furniture and Equipment	(72,690)	(61,277)	(9,269)	(2,145)	Other Gas Plant	(36,944)	(24,333)	(5,549)	(3,720)	(1,288)	(856)
392 Transportation Equip	(1,194,963)	(1,145,917)	(25,792)	(23,254)	Other Gas Plant	(690,872)	(455,045)	(15,441)	(10,351)	(13,971)	(9,283)
394 Tools, Shop & Garage	(705,227)	(691,649)	(2,611)	(10,967)	Other Gas Plant	(416,994)	(274,654)	(1,563)	(1,048)	(6,589)	(4,378)
396 Power Operated Equipment	(296,313)	(296,313)	-	-	Other Gas Plant	(178,647)	(117,666)	-	-	-	-
397 Communication Equip	(232,331)	(33,379)	(166,705)	(32,247)	Other Gas Plant	(20,124)	(13,255)	(99,804)	(66,900)	(19,374)	(12,872)
398 Miscellaneous Equip	(37,027)	(21,270)	(14,043)	(1,714)	Other Gas Plant	(12,824)	(8,446)	(8,407)	(5,636)	(1,030)	(684)
Total Accumulated Depreciation	(72,990,047)	(64,882,159)	(7,538,752)	(569,136)		(39,409,660)	(25,472,499)	(4,508,758)	(3,029,994)	(345,341)	(223,795)

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COST OF SERVICE STUDY -- COST CLASSIFICATION

Description:	Texas	Joint	Jurisdictional	Non-	Classification	Joint		Jurisdictional Only		Non-Jurisdictional Only	
	Total		Only	Jurisdictional Only		Customer	Capacity	Customer	Capacity	Customer	Capacity
Other Rate Base Items											
Prepayments	1,181,498	1,181,498	-	-	Total Gas Plant	445,686	293,552	243,000	162,887	21,852	14,519
Materials and Supplies Inventories	1,851,614	1,851,614	-	-	Total Gas Plant	698,469	460,048	380,824	255,273	34,247	22,754
Customer Deposits	(1,200,560)	(1,200,560)	-	-	Direct	(1,200,560)	-	-	-	-	-
Contributions in Aid of Construction	(23,143,350)	(23,143,350)	-	-	CIAC	(7,342,251)	(4,961,235)	(5,977,807)	(4,039,397)	(490,926)	(331,734)
Accumulated Deferred Income Taxes	(25,703,718)	(25,703,718)	-	-	Total Gas Plant	(9,695,996)	(6,386,291)	(5,286,523)	(3,543,644)	(475,403)	(315,861)
Excess ADIT	(9,311,525)	(9,311,525)	-	-	Total Gas Plant	(3,512,508)	(2,313,522)	(1,915,116)	(1,283,734)	(172,221)	(114,425)
Total Other Rate Base Items	(56,326,042)	(56,326,042)	-	-		(20,607,160)	(12,907,447)	(12,555,621)	(8,448,615)	(1,082,451)	(724,747)
Rate Base	119,850,523					33,974,192	23,527,463	34,182,097	22,872,757	3,180,669	2,113,346
Operation and Maintenance Expenses											
813 Other Gas Supply Expenses	157,163	157,163	-	-	Total Gas Plant	59,285	39,048	32,324	21,667	2,907	1,931
858 Trans. & Comp. Of Gas by Others	-	-	-	-	Total Gas Plant	-	-	-	-	-	-
863 Maintenance of Mains	96,421	96,421	-	-	Pipe Plant	33,114	22,376	22,529	15,224	1,897	1,282
870 Operation Supervision & Engineering	6,967,030	6,967,030	-	-	Total Gas Plant	2,628,114	1,731,014	1,432,920	960,510	128,859	85,614
874 Mains and Services Expenses	1,119,415	1,119,415	-	-	Pipe Plant	384,438	259,777	261,557	176,742	22,021	14,880
880 Other Expenses	789,857	789,857	-	-	Total Gas Plant	297,951	196,246	162,451	108,894	14,609	9,706
881 Rents	200,696	200,696	-	-	Total Gas Plant	75,707	49,864	41,277	27,669	3,712	2,466
886 Maintenance of Structures	7,528	7,528	-	-	Total Gas Plant	2,840	1,870	1,548	1,038	139	93
887 Maintenance of Mains	395,212	395,212	-	-	Pipe Plant	135,727	91,715	92,343	62,399	7,774	5,253
888 Maint of M&R Station Equip-General	2,249	2,249	-	-	Meter Plant	1,298	529	254	104	46	19
889 Maint of M&R Station Equip-City Gate	440,411	440,411	-	-	Meter Plant	254,085	103,667	49,742	20,295	8,964	3,657
894 Maintenance of Other Equipment	520,385	520,385	-	-	Total Gas Plant	196,300	129,294	107,028	71,743	9,625	6,395
Total O&M Expenses	10,696,368	10,696,368	-	-		4,068,858	2,625,401	2,203,975	1,466,285	200,552	131,297
Administrative and General Expenses											
904 Uncollectible Accounts	162,750	162,750	-	-	Total Gas Plant	61,393	40,437	33,473	22,438	3,010	2,000
910 Miscellaneous Customer Service Exp	123,824	123,824	-	-	Total Gas Plant	46,709	30,765	25,467	17,071	2,290	1,522
913 Advertising Expenses	21,153	21,153	-	-	O&M	8,047	5,192	4,359	2,900	397	260
920 Administrative and General Salaries	1,241,542	1,241,542	-	-	O&M	472,278	304,734	255,818	170,194	23,278	15,240
921 Office Supplies and Expenses	173,311	173,311	-	-	O&M	65,927	42,539	35,711	23,758	3,250	2,127
922 Administrative Expenses Transferred-Credit	(1,117,423)	(1,117,423)	-	-	O&M	(425,064)	(274,269)	(230,244)	(153,179)	(20,951)	(13,716)
923 Outside Services Employed	1,500,128	1,500,128	-	-	O&M	570,643	368,203	309,100	205,641	28,127	18,414
924 Property Insurance	867,137	867,137	-	-	Total Gas Plant	327,103	215,447	178,345	119,548	16,038	10,656
926 Employee Pension and Benefits	1,418,128	1,418,128	-	-	O&M	539,451	348,077	292,204	194,401	26,589	17,407
930 Miscellaneous General Expense	1,180,349	1,180,349	-	-	O&M	449,000	289,714	243,210	161,805	22,131	14,489
931 Rents	5,641	5,641	-	-	O&M	2,146	1,385	1,162	773	106	69
Total A&G Expenses	5,576,542	5,576,542	-	-		2,117,633	1,372,223	1,148,605	765,349	104,264	68,467
Taxes Other than Income											
408 Payroll Taxes	602,078	602,078	-	-	A&G	228,633	148,154	124,010	82,632	11,257	7,392
408 Property Taxes	2,027,037	2,027,037	-	-	Total Gas Plant	764,642	503,633	416,904	279,458	37,491	24,909
408 Texas Franchise Tax	52,031	52,031	-	-	Total Gas Plant	19,627	12,927	10,701	7,173	962	639
408 Miscellaneous	111,076	111,076	-	-	Total Gas Plant	41,900	27,598	22,845	15,313	2,054	1,365
Total Taxes Other than Income	2,792,222	2,792,222	-	-		1,054,802	692,312	574,461	384,576	51,765	34,306

WEST TEXAS GAS UTILITY, LLC
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COST OF SERVICE STUDY -- COST CLASSIFICATION

Description:	Texas	Joint	Jurisdictional	Non-	Classification	Joint		Jurisdictional Only		Non-Jurisdictional Only	
	Total		Only	Jurisdictional Only		Customer	Capacity	Customer	Capacity	Customer	Capacity
Depreciation and Amortization Expenses											
403 Plant Depreciation Expense	5,909,981	5,909,981	-	-	Total Gas Plant	2,229,372	1,468,381	1,215,515	814,780	109,308	72,625
CIAC Field Lines	(6,050)	(6,050)	-	-	CIAC-332	(3,619)	(2,427)	-	-	(2)	(2)
CIAC Mains	(42,363)	(42,363)	-	-	CIAC-367	(20,440)	(13,812)	(4,356)	(2,944)	(484)	(327)
CIAC Mains	(650,525)	(650,525)	-	-	CIAC-376	(198,995)	(134,467)	(174,966)	(118,230)	(14,243)	(9,625)
Total D&A Expenses	5,211,043					2,006,319	1,317,675	1,036,193	693,606	94,578	62,671
Return On Investment	9,713,453	9,713,453	-	-	Rate Base	2,753,486	1,906,816	2,770,336	1,853,755	257,782	171,279
Income Taxes	1,713,989	1,713,989	-	-	Rate Base	485,867	336,468	488,840	327,105	45,487	30,223
Other Income	(1,087,324)	(1,087,324)	-	-	Rev. Req.	(380,280)	(251,274)	(250,407)	(167,214)	(22,975)	(15,174)
REVENUE REQUIREMENTS	34,616,294					12,106,686	7,999,622	7,972,003	5,323,462	731,453	483,070

COST CLASSIFICATION FACTORS:	Classification Factor Name	Joint		Jurisdictional			
		Total Texas		Domestic		Non-Domestic	
		Customer	Capacity	Customer	Capacity	Customer	Capacity
Pipe (Schedule J-1)							
2-inch Pipe Replacement Cost			435,584,442				
Total System Pipe Replacement Cost			729,922,918				
Pipe Classification Factor	Pipe	59.68%	40.32%	59.68%	40.32%	59.68%	40.32%
Meters (Schedule J-2)							
Basic Meter Replacement Cost			8,232,263				
Total System Meter Replacement Cost			11,591,033				
Meters Classification Factor	Meters	71.02%	28.98%	71.02%	28.98%	71.02%	28.98%
Aggregate (Schedules J-1 and J-2)							
2-inch Pipe and Basic Meter Replacement Cost			443,816,705				
Total System Pipe and Meter Replacement Cost			741,513,952				
Aggregate Classification Factor	Aggregate	59.85%	40.15%	59.85%	40.15%	59.85%	40.15%
Other Gas Plant			83,943,344	55,289,488	50,852,636	34,087,370	4,382,564
Other Gas Plant Classification Factor	Other Gas Plant	60.29%	39.71%	59.87%	40.13%	60.08%	39.92%
Total Gas Plant			93,991,012	61,907,409	51,246,475	34,351,367	4,608,461
Total Gas Plant Classification Factor	Total Gas Plant	37.72%	24.85%	20.57%	13.79%	1.85%	1.23%
Pipe Plant			73,223,033	49,479,169	49,818,166	33,663,744	4,194,214
Total Pipe Plant Classification Factor	Pipe Plant	34.34%	23.21%	23.37%	15.79%	1.97%	1.33%
Meter Plant			5,253,750	2,143,535	1,028,530	419,641	185,351
Total Meter Plant Classification Factor	Meter Plant	57.69%	23.54%	11.29%	4.61%	2.04%	0.83%

WEST TEXAS GAS UTILITY, LLC
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COST OF SERVICE STUDY -- COST CLASSIFICATION

Description:	Texas Total	Joint	Jurisdictional Only	Non- Jurisdictional Only	Classification Factor	Joint		Jurisdictional Only		Non-Jurisdictional Only	
						Customer	Capacity	Customer	Capacity	Customer	Capacity
Contributions in Aid of Construction											
332 Field Lines	(54,418)	(54,418)	-	-	Plant 332	(32,549)	(21,833)	-	-	(21)	(14)
367 Mains	(1,397,789)	(1,397,789)	-	-	Plant 367	(674,412)	(455,722)	(143,742)	(97,131)	(15,982)	(10,799)
376 Mains	(21,691,143)	(21,691,143)	-	-	Plant 376	(6,635,290)	(4,483,679)	(5,834,065)	(3,942,266)	(474,922)	(320,920)
CIAC Allocation	(23,143,350)	(23,143,350)			CIAC	(7,342,251)	(4,961,235)	(5,977,807)	(4,039,397)	(490,926)	(331,734)
Operation and Maintenance Expenses						4,068,858	2,625,401	2,203,975	1,466,285	200,552	131,297
O&M Classification Factor					O&M	38.04%	24.54%	20.60%	13.71%	1.87%	1.23%
Administrative and General Expenses						2,117,633	1,372,223	1,148,605	765,349	104,264	68,467
A&G Classification Factor					A&G	37.97%	24.61%	20.60%	13.72%	1.87%	1.23%
Rate Base						33,974,192	23,527,463	34,182,097	22,872,757	3,180,669	2,113,346
Rate Base Classification Factor					Rate Base	28.35%	19.63%	28.52%	19.08%	2.65%	1.76%
Revenue Requirements						12,486,966	8,250,896	8,222,409	5,490,675	754,428	498,243
Revenue Requirements Classification Factor					Rev. Req.	34.97%	23.11%	23.03%	15.38%	2.11%	1.40%

COST OF SERVICE STUDY --- COST ALLOCATION

	Schedule J-1						Jurisdiction/Class Allocation	Jurisdiction/Class Allocation						
	Joint Costs		Jurisdictional Only		Non-Jurisdictional Only			Cost Allocation Factor	Domestic		Non-Domestic		Non-Jurisdictional	
	Customer	Capacity	Customer	Capacity	Customer	Capacity			Customer	Capacity	Customer	Capacity	Customer	Capacity
Plant in Service														
301 Organization	34,891	22,981	-	-	-	-	Other Gas Plant	22,484	6,865	4,094	5,024	8,313	11,092	
302 Franchises and Consents	120,580	79,420	-	-	-	-	Other Gas Plant	77,702	23,725	14,148	17,363	28,729	38,333	
303 Intangible Plant	168,532	111,004	37,317	25,014	-	-	Other Gas Plant	140,172	47,603	25,523	34,838	40,154	53,577	
332 Field Lines	1,822,996	1,222,804	-	-	1,203	807	Throughput	47,589	31,921	28,393	19,045	1,748,217	1,172,645	
334 Field M&R Station Equipment	59,853	40,147	-	-	-	-	Throughput	1,562	1,048	932	625	57,358	38,474	
365 Land and Rights-of-Way	3,219,555	2,159,569	-	-	-	-	Design Day	468,097	313,984	342,648	229,837	2,408,810	1,615,748	
366 Structures and Improvements	-	-	-	-	-	-	Design Day	-	-	-	-	-	-	
367 Mains	21,862,767	14,773,378	4,659,752	3,148,745	518,093	350,092	Design Day	5,869,051	3,965,908	4,296,161	2,903,055	16,875,400	11,403,253	
368 Compressor Station Equipment	23,333	15,651	-	-	-	-	Design Day	3,392	2,276	2,483	1,666	17,457	11,710	
369 M&R Station Equipment	930,995	379,847	69,453	28,337	3,429	1,399	Design Day	175,459	71,587	128,436	52,402	699,982	285,593	
371 Other Equipment	126,422	84,800	5,941	3,985	1,796	1,205	Design Day	21,811	14,630	15,965	10,709	96,382	64,650	
376 Mains	51,360,267	34,705,791	45,158,413	30,514,998	3,676,121	2,484,074	Customers/DD	78,800,655	22,664,271	10,919,704	16,590,305	10,474,443	28,450,288	
377 Compressors	214,402	143,814	-	-	-	-	Customers/DD	163,382	20,909	22,641	15,306	28,379	107,599	
378 M&R Station Equipment - General	4,322,754	1,763,688	959,077	391,304	181,921	74,224	Customers/DD	4,136,445	482,352	573,203	353,083	754,104	1,393,782	
387 Other Equipment	389,789	256,736	18,880	12,656	5,752	3,822	Other Gas Plant	267,155	84,001	48,644	61,475	98,623	127,737	
389 Rights-of-Way	3,915,583	2,579,008	2,946	1,974	-	-	Other Gas Plant	2,525,715	771,553	459,890	564,654	932,923	1,244,776	
390 Office Buildings	2,575,685	1,696,481	68,771	46,098	105,629	70,181	Other Gas Plant	1,717,964	533,399	312,812	390,363	719,309	888,999	
391 Office Furniture and Equipment	140,982	92,858	18,784	12,591	4,303	2,859	Other Gas Plant	106,740	35,009	19,436	25,621	37,894	47,678	
392 Transportation Equip	1,686,459	1,110,790	15,203	10,191	46,590	30,955	Other Gas Plant	1,099,625	337,705	200,223	247,146	448,404	567,085	
394 Tools, Shop & Garage	661,955	435,998	12,915	8,657	25,870	17,188	Other Gas Plant	437,493	135,242	79,660	98,976	183,587	227,626	
396 Power Operated Equipment	214,929	141,563	-	-	-	-	Other Gas Plant	138,501	42,288	25,219	30,948	51,209	68,326	
397 Communication Equip	84,861	55,894	194,367	130,287	34,680	23,042	Other Gas Plant	219,113	91,927	39,897	67,276	54,899	50,020	
398 Miscellaneous Equip	53,422	35,186	24,657	16,528	3,072	2,041	Other Gas Plant	55,285	20,055	10,066	14,677	15,800	19,024	
Total Plant in Service	93,991,012	61,907,409	51,246,475	34,351,367	4,608,461	3,061,888		96,495,392	29,698,257	17,570,179	21,734,394	35,780,378	47,888,012	
Accumulated Depreciation														
301 Organization	(34,891)	(22,981)	-	-	-	-	Gas Plant A/D	(20,686)	(4,307)	(3,670)	(3,148)	(10,535)	(15,526)	
302 Franchises and Consents	(120,580)	(79,420)	-	-	-	-	Gas Plant A/D	(71,490)	(14,884)	(12,683)	(10,880)	(36,407)	(53,656)	
303 Intangible Plant	(377,620)	(248,720)	-	-	-	-	Gas Plant A/D	(223,885)	(46,612)	(39,718)	(34,073)	(114,017)	(168,036)	
332 Field Lines	(2,031,996)	(1,362,994)	-	-	(250)	(167)	Throughput	(53,045)	(35,581)	(31,649)	(21,229)	(1,947,551)	(1,306,352)	
334 Field M&R Station Equipment	(30,217)	(20,268)	-	-	-	-	Throughput	(789)	(529)	(471)	(316)	(28,957)	(19,424)	
365 Land and Rights-of-Way	(366,346)	(245,732)	-	-	-	-	Design Day	(53,264)	(35,727)	(38,989)	(26,153)	(274,093)	(183,852)	
366 Structures and Improvements	-	-	-	-	-	-	Design Day	-	-	-	-	-	-	
367 Mains	(7,570,864)	(5,115,877)	(394,494)	(266,573)	(58,851)	(39,767)	Design Day	(1,328,509)	(897,717)	(972,472)	(657,131)	(5,723,227)	(3,867,370)	
368 Compressor Station Equipment	(29,634)	(19,878)	-	-	-	-	Design Day	(4,309)	(2,890)	(3,154)	(2,116)	(22,172)	(14,872)	
369 M&R Station Equipment	(561,507)	(229,095)	(5,758)	(2,349)	(804)	(328)	Design Day	(84,963)	(34,665)	(62,193)	(25,375)	(420,913)	(171,733)	
371 Other Equipment	(122,327)	(82,053)	(2,880)	(1,932)	(721)	(483)	Design Day	(19,448)	(13,045)	(14,236)	(9,549)	(92,243)	(61,874)	
376 Mains	(20,484,269)	(13,841,882)	(3,904,248)	(2,638,226)	(187,822)	(126,917)	Customers/DD	(19,038,826)	(3,535,719)	(2,638,282)	(2,588,156)	(2,899,230)	(10,483,150)	
377 Compressors	(233,462)	(156,598)	-	-	-	-	Customers/DD	(177,907)	(22,768)	(24,653)	(16,666)	(30,902)	(117,164)	
378 M&R Station Equipment - General	(3,420,259)	(1,395,469)	(53,646)	(21,888)	(32,157)	(13,120)	Customers/DD	(2,653,479)	(215,527)	(367,703)	(157,766)	(484,881)	(1,057,183)	
387 Other Equipment	(322,766)	(212,591)	(6,282)	(4,211)	(1,330)	(884)	Gas Plant A/D	(196,699)	(42,274)	(34,895)	(30,901)	(98,784)	(144,510)	
389 Rights-of-Way	(1,547,341)	(1,019,160)	-	-	-	-	Gas Plant A/D	(917,396)	(190,998)	(162,749)	(139,616)	(467,196)	(688,546)	
390 Office Buildings	(799,177)	(526,380)	(10,684)	(7,162)	(21,155)	(14,055)	Gas Plant A/D	(482,895)	(102,785)	(85,667)	(75,134)	(262,454)	(369,679)	
391 Office Furniture and Equipment	(36,944)	(24,333)	(5,549)	(3,720)	(1,288)	(856)	Gas Plant A/D	(26,616)	(6,709)	(4,722)	(4,904)	(12,443)	(17,295)	
392 Transportation Equip	(690,872)	(455,045)	(15,441)	(10,351)	(13,971)	(9,283)	Gas Plant A/D	(422,723)	(91,258)	(74,992)	(66,708)	(222,570)	(316,712)	
394 Tools, Shop & Garage	(416,994)	(274,654)	(1,563)	(1,048)	(6,589)	(4,378)	Gas Plant A/D	(248,558)	(52,077)	(44,095)	(38,068)	(132,494)	(189,935)	
396 Power Operated Equipment	(178,647)	(117,666)	-	-	-	-	Gas Plant A/D	(105,917)	(22,051)	(18,790)	(16,119)	(53,940)	(79,495)	
397 Communication Equip	(20,124)	(13,255)	(99,804)	(66,900)	(19,374)	(12,872)	Gas Plant A/D	(96,698)	(41,133)	(17,154)	(30,067)	(25,451)	(21,827)	
398 Miscellaneous Equip	(12,824)	(8,446)	(8,407)	(5,636)	(1,030)	(684)	Gas Plant A/D	(14,744)	(4,839)	(2,616)	(3,537)	(4,902)	(6,390)	
Total Accumulated Depreciation	(39,409,660)	(25,472,499)	(4,508,758)	(3,029,994)	(345,341)	(223,795)		(26,242,845)	(5,414,095)	(4,655,551)	(3,957,611)	(13,365,362)	(19,354,582)	

WEST TEXAS GAS UTILITY, LLC
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COST OF SERVICE STUDY --- COST ALLOCATION

	Schedule J-1						Cost Allocation Factor	Jurisdiction/Class Allocation					
	Joint Costs		Jurisdictional Only		Non-Jurisdictional Only			Domestic		Non-Domestic		Non-Jurisdictional	
	Customer	Capacity	Customer	Capacity	Customer	Capacity		Customer	Capacity	Customer	Capacity	Customer	Capacity
Other Rate Base Items													
Prepayments	445,686	293,552	243,000	162,887	21,852	14,519	Total Gas Plant	492,576	181,831	89,690	133,071	128,274	156,057
Materials and Supplies Inventories	698,469	460,048	380,824	255,273	34,247	22,754	Total Gas Plant	771,952	284,961	140,559	208,546	201,028	244,568
Customer Deposits	(1,200,560)	-	-	-	-	-	Customers	(914,871)	-	(126,777)	-	(158,913)	-
Contributions in Aid of Construction	(7,342,251)	(4,961,235)	(5,977,807)	(4,039,397)	(490,926)	(331,734)	CIAC	(9,885,784)	(3,849,356)	(1,778,875)	(2,817,114)	(2,146,325)	(2,665,896)
Accumulated Deferred Income Taxes	(9,695,996)	(6,386,291)	(5,286,523)	(3,543,644)	(475,403)	(315,861)	Total Gas Plant	(10,716,081)	(3,955,762)	(1,951,217)	(2,894,988)	(2,790,624)	(3,395,047)
Excess ADIT	(3,512,508)	(2,313,522)	(1,915,116)	(1,283,734)	(172,221)	(114,425)	Total Gas Plant	(3,882,048)	(1,433,029)	(706,855)	(1,048,749)	(1,010,942)	(1,229,902)
Total Other Rate Base Items	(20,607,160)	(12,907,447)	(12,555,621)	(8,448,615)	(1,082,451)	(724,747)		(24,134,255)	(8,771,356)	(4,333,475)	(6,419,234)	(5,777,502)	(6,890,220)
Rate Base	33,974,192	23,527,463	34,182,097	22,872,757	3,180,669	2,113,346		46,118,291	15,512,807	8,581,153	11,357,548	16,637,513	21,643,210
Operation and Maintenance Expenses													
813 Other Gas Supply Expenses	59,285	39,048	32,324	21,667	2,907	1,931	Throughput	21,793	14,590	13,002	8,705	59,721	39,352
858 Trans. & Comp. Of Gas by Others	-	-	-	-	-	-	Throughput	-	-	-	-	-	-
863 Maintenance of Mains	33,114	22,376	22,529	15,224	1,897	1,282	Customers/DD	45,021	12,043	6,239	8,815	6,280	18,023
870 Operation Supervision & Engineering	2,628,114	1,731,014	1,432,920	960,510	128,859	85,614	Customers/DD	3,261,240	806,241	451,922	590,171	476,730	1,380,726
874 Mains and Services Expenses	384,438	259,777	261,557	176,742	22,021	14,880	Customers/DD	522,679	139,815	72,430	102,345	72,907	209,240
880 Other Expenses	297,951	196,246	162,451	108,894	14,609	9,706	Customers/DD	369,729	91,404	51,235	66,908	54,047	156,534
881 Rents	75,707	49,864	41,277	27,669	3,712	2,466	Customers/DD	93,945	23,225	13,018	17,001	13,733	39,774
886 Maintenance of Structures	2,840	1,870	1,548	1,038	139	93	Customers/DD	3,524	871	488	638	515	1,492
887 Maintenance of Mains	135,727	91,715	92,343	62,399	7,774	5,253	Customers/DD	184,533	49,362	25,571	36,133	25,740	73,873
888 Maint of M&R Station Equip-General	1,298	529	254	104	46	19	Customers/DD	1,212	137	168	100	218	415
889 Maint of M&R Station Equip-City Gate	254,085	103,667	49,742	20,295	8,964	3,657	Customers/DD	237,311	26,790	32,885	19,610	42,596	81,219
894 Maintenance of Other Equipment	196,300	129,294	107,028	71,743	9,625	6,395	Customers/DD	243,590	60,220	33,755	44,081	35,608	103,130
Total O&M Expenses	4,068,858	2,625,401	2,203,975	1,466,285	200,552	131,297		4,984,576	1,224,698	700,714	894,507	788,095	2,103,778
Administrative and General Expenses													
904 Uncollectible Accounts	61,393	40,437	33,473	22,438	3,010	2,000	Customers/DD	76,183	18,834	10,557	13,786	11,136	32,254
910 Miscellaneous Customer Service Exp	46,709	30,765	25,467	17,071	2,290	1,522	Customers/DD	57,962	14,329	8,032	10,489	8,473	24,540
913 Advertising Expenses	8,047	5,192	4,359	2,900	397	260	Customers/DD	9,960	2,429	1,380	1,778	1,462	4,144
920 Administrative and General Salaries	472,278	304,734	255,818	170,194	23,278	15,240	O&M	587,948	186,731	82,652	136,386	80,775	167,050
921 Office Supplies and Expenses	65,927	42,539	35,711	23,758	3,250	2,127	O&M	82,074	26,066	11,538	19,039	11,276	23,319
922 Administrative Expenses Transferred-Credit	(425,064)	(274,269)	(230,244)	(153,179)	(20,951)	(13,716)	O&M	(529,170)	(168,063)	(74,389)	(122,752)	(72,700)	(150,350)
923 Outside Services Employed	570,643	368,203	309,100	205,641	28,127	18,414	O&M	710,405	225,623	99,866	164,793	97,599	201,843
924 Property Insurance	327,103	215,447	178,345	119,548	16,038	10,656	Customers/DD	405,903	100,347	56,248	73,454	59,335	171,849
926 Employee Pension and Benefits	539,451	348,077	292,204	194,401	26,589	17,407	O&M	671,572	213,290	94,407	155,785	92,264	190,810
930 Miscellaneous General Expense	449,000	289,714	243,210	161,805	22,131	14,489	O&M	558,969	177,527	78,578	129,664	76,794	158,817
931 Rents	2,146	1,385	1,162	773	106	69	O&M	2,671	848	376	620	367	759
Total A&G Expenses	2,117,633	1,372,223	1,148,605	765,349	104,264	68,467		2,634,477	797,962	369,244	583,043	366,781	825,035
Taxes Other than Income													
408 Payroll Taxes	228,633	148,154	124,010	82,632	11,257	7,392	A&G	287,630	104,193	40,434	76,101	35,836	57,883
408 Property Taxes	764,642	503,633	416,904	279,458	37,491	24,909	Customers/DD	948,848	234,574	131,485	171,708	138,703	401,718
408 Texas Franchise Tax	19,627	12,927	10,701	7,173	962	639	Cost of Service	23,723	8,862	3,837	6,482	3,731	5,396
408 Miscellaneous	41,900	27,598	22,845	15,313	2,054	1,365	Throughput	15,402	10,312	9,189	6,152	42,208	27,812
Total Taxes Other than Income	1,054,802	692,312	574,461	384,576	51,765	34,306		1,275,604	357,940	184,946	260,444	220,478	492,810

WEST TEXAS GAS UTILITY, LLC
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COST OF SERVICE STUDY --- COST ALLOCATION

	Schedule J-1						Cost Allocation Factor	Jurisdiction/Class Allocation					
	Customer		Capacity		Customer			Domestic		Non-Domestic		Non-Jurisdictional	
	Customer	Capacity	Customer	Capacity	Customer	Capacity		Customer	Capacity	Customer	Capacity	Customer	Capacity
Depreciation and Amortization Expenses													
403 Plant Depreciation Expense	2,229,372	1,468,381	1,215,515	814,780	109,308	72,625	Total Gas Plant	2,463,917	909,537	448,638	665,636	641,640	780,613
CIAC Field Lines	(3,619)	(2,427)	-	-	(2)	(2)	CIAC	(2,375)	(742)	(427)	(543)	(818)	(1,144)
CIAC Mains	(20,440)	(13,812)	(4,356)	(2,944)	(484)	(327)	CIAC	(17,109)	(5,923)	(3,079)	(4,335)	(5,093)	(6,825)
CIAC Mains	(198,995)	(134,467)	(174,966)	(118,230)	(14,243)	(9,625)	CIAC	(278,907)	(109,382)	(50,187)	(80,050)	(59,109)	(72,889)
Total D&A Expenses	2,006,319	1,317,675	1,036,193	693,606	94,578	62,671		2,165,526	793,490	394,944	580,708	576,620	699,756
Return On Investment	2,753,486	1,906,816	2,770,336	1,853,755	257,782	171,279	Rate Base	4,115,818	1,679,938	765,823	1,229,950	899,962	1,021,961
Income Taxes	485,867	336,468	488,840	327,105	45,487	30,223	Rate Base	726,257	296,434	135,134	217,031	158,803	180,330
Other Income	(380,280)	(251,274)	(250,407)	(167,214)	(22,975)	(15,174)	Cost of Service	(496,708)	(188,303)	(80,342)	(137,725)	(76,612)	(107,633)
COST OF SERVICE	12,106,686	7,999,622	7,972,003	5,323,462	731,453	483,070		15,405,551	4,962,159	2,470,463	3,627,958	2,934,127	5,216,036

COST ALLOCATION FACTORS:

Customer Count (Schedule K)								17,924		2,484		3,113	
Customer Allocation Factor -- Joint Costs							Customers	76.20%	0.00%	10.56%	0.00%	13.24%	0.00%
Customer Allocation Factor -- Jurisdictional Only Costs								87.83%	0.00%	12.17%	0.00%		
Customer Allocation Factor -- Non-Jurisdictional Only Costs												100.00%	0.00%
Design Day (Schedule J-5)										20,593		15,074	105,970
Design Day Allocation Factor -- Joint Costs							Design Day	14.54%	14.54%	10.64%	10.64%	74.82%	74.82%
Design Day Allocation Factor -- Jurisdictional Costs								57.74%	57.74%	42.26%	42.26%		
Design Day Allocation Factor -- Non-Jurisdictional Costs												100.00%	100.00%
Throughput (Schedule K)										1,063,235		634,364	39,031,669
Throughput Allocation Factor -- Joint Costs							Throughput	2.61%	2.61%	1.56%	1.56%	95.83%	95.83%
Throughput Allocation Factor -- Jurisdictional Costs								62.63%	62.63%	37.37%	37.37%		
Throughput Allocation Factor -- Non-Jurisdictional Costs												100.00%	100.00%
Other Gas Plant								89,687,444	27,568,885	16,330,567	20,176,032	33,160,534	44,543,741
Other Gas Plant Allocation Factor -- Joint Costs							Other Gas Plant	64.44%	29.87%	11.73%	21.86%	23.83%	48.27%
Other Gas Plant Allocation Factor -- Jurisdictional Costs								84.60%	57.74%	15.40%	42.26%		
Other Gas Plant Allocation Factor -- Non-Jurisdictional Costs												100.00%	100.00%
Other Gas Plant Accumulated Depreciation								(23,414,538)	(4,794,169)	(4,153,801)	(3,504,456)	(11,924,170)	(17,282,973)
Other Gas Plant Acc. Dep. Allocation Factor -- Joint Costs							Gas Plant A/D	59.29%	18.74%	10.52%	13.70%	30.19%	67.56%
Other Gas Plant Acc. Dep. Allocation Factor -- Jurisdictional Costs								84.93%	57.77%	15.07%	42.23%		
Other Gas Plant Acc. Dep. Allocation Factor -- Non-Jurisdictional Costs												100.00%	100.00%

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COST OF SERVICE STUDY --- COST ALLOCATION

	Customer	Capacity	Jurisdiction/Class Allocation					
			Jurisdictional		Non-Jurisdictional		Non-Jurisdictional	
			Customer	Capacity	Customer	Capacity	Customer	Capacity
Contributions in Aid of Construction								
332 Field Lines								
367 Mains								
376 Mains								
Total CIAC								
CIAC Allocation Factor -- Joint Costs								
CIAC Allocation Factor -- Jurisdictional Costs								
CIAC Allocation Factor -- Non-Jurisdictional Costs								
Operation and Maintenance Expenses								
O&M Allocation Factor -- Joint Costs								
O&M Allocation Factor -- Jurisdictional Costs								
O&M Allocation Factor -- Non-Jurisdictional Costs								
Administrative and General Expenses (Account 920)								
A&G Allocation Factor -- Joint Costs								
A&G Allocation Factor -- Jurisdictional Costs								
A&G Allocation Factor -- Non-Jurisdictional Costs								
Total Gas Plant								
Total Gas Plant Allocation Factor -- Joint Costs								
Total Gas Plant Allocation Factor -- Jurisdictional Costs								
Total Gas Plant Allocation Factor -- Non-Jurisdictional Costs								
Rate Base								
Rate Base Allocation Factor -- Joint Costs								
Rate Base Allocation Factor -- Jurisdictional Costs								
Rate Base Allocation Factor -- Non-Jurisdictional Costs								
Cost of Service								
Cost of Service Allocation Factor -- Joint Costs								
Cost of Service Allocation Factor -- Jurisdictional Costs								
Cost of Service Allocation Factor -- Non-Jurisdictional Costs								

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PIPE REPLACEMENT COST ANALYSIS

<u>Pipe Size (inches)</u>	<u>Installed Length (feet)</u>	<u>Replacement Cost (per foot)</u>	<u>Total System Replacement Cost</u>	<u>Replacement Cost with 2-inch Pipe</u>
				14.50
0.50	2,606	12.00	31,271	37,786
0.75	6,545	12.00	78,541	94,904
1.00	350,234	12.00	4,202,807	5,078,392
1.25	238,216	14.50	3,454,128	3,454,128
1.50	173,872	14.50	2,521,150	2,521,150
2.00	14,715,074	14.50	213,368,566	213,368,566
2.25	63,559	14.50	921,609	921,609
2.50	46,961	14.50	680,940	680,940
2.75	31,779	14.50	460,796	460,796
2.88	64,165	14.50	930,400	930,400
3.00	3,864,549	21.00	81,155,528	56,035,960
3.38	109,566	21.00	2,300,878	1,588,701
3.50	15,211	21.00	319,437	220,564
4.00	5,147,519	28.00	144,130,544	74,639,032
5.00	13,737	28.00	384,622	199,179
6.00	3,571,122	40.00	142,844,875	51,781,267
8.00	444,825	54.00	24,020,546	6,449,961
10.00	782,462	63.00	49,295,135	11,345,706
12.00	202,613	73.00	14,790,734	2,937,886
22.00	195,691	225.00	44,030,410	2,837,515
Totals	30,040,306		729,922,918	435,584,442

Customer-related Cost Percentage **59.68%**

Capacity-related Cost Percentage **40.32%**

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METER REPLACEMENT COST ANALYSIS

Description	Number of Services	Cost per Service			Total Service Replacement Cost	Replacement Cost with Residential Meter
		Meter	Riser	Total		
						350.00
Residential Meters	17,924	100.00	250.00	350.00	6,273,283	6,273,283
Small Commercial Meters	2,463	500.00	250.00	750.00	1,846,875	861,875
Irrigation Meters	2,942	750.00	250.00	1,000.00	2,942,417	1,029,846
Large Commercial Meters	192	2,500.00	250.00	2,750.00	528,458	67,258
Totals	23,521				11,591,033	8,232,263
Customer-related Cost Percentage						71.02%
Capacity-related Cost Percentage						28.98%

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DESIGN DAY ANALYSIS

Description	Reference	Peak Design Day -- January 2023			
		North	West	South	Total
JURISDICTIONAL:					
Domestic					
Adjusted Mcf per day -- January 2023	Sch. K-1,K-2,K-3	3,977.88	1,648.23	626.26	6,252.38
Base Use -- Mcf per day	Sch. K-4,K-5,K-6	482.98	241.89	77.10	801.98
Adjusted Weather Sensitive Load -- Mcf per day		3,494.90	1,406.34	549.16	5,450.40
Heating Degree Days per day -- January 2023	Sch. K-4,K-5,K-6	24.13	17.74	8.13	
Heat Load Volume per HDD		144.84	79.27	67.56	
Design Day HDD's		73.00	66.00	59.00	
Design Day Heat Load Volume -- Mcf per day		10,573.47	5,231.58	3,985.79	19,790.84
Anticipated Design Day Volume -- Mcf per day		11,056.46	5,473.47	4,062.89	20,592.81
Non-Domestic					
Adjusted Mcf per day -- January 2023	Sch. K-1,K-2,K-3	1,983.49	1,983.49	693.77	4,660.74
Base Use -- Mcf per day	Sch. K-4,K-5,K-6	184.37	515.46	250.12	949.96
Adjusted Weather Sensitive Load -- Mcf per day		1,799.12	1,468.03	443.64	3,710.79
Heating Degree Days per day -- January 2023	Sch. K-4,K-5,K-6	24.13	17.74	8.13	
Heat Load Volume per HDD		74.56	82.74	54.58	
Design Day HDD's		73.00	66.00	59.00	
Design Day Heat Load Volume -- Mcf per day		5,443.05	5,461.06	3,219.93	14,124.04
Anticipated Design Day Volume -- Mcf per day		5,627.42	5,976.52	3,470.05	15,073.99
NON-JURISDICTIONAL:					
Non-Domestic					
Adjusted Mcf per day -- January 2023	Sch. K-1,K-2,K-3	1,983.49	1,330.57	2,076.20	5,390.26
Base Use -- Mcf per day	Sch. K-4,K-5,K-6	184.37	1,008.23	1,350.27	2,542.87
Adjusted Weather Sensitive Load -- Mcf per day		1,799.12	322.34	725.93	2,847.39
Heating Degree Days per day -- January 2023	Sch. K-4,K-5,K-6	24.13	17.74	8.13	
Heat Load Volume per HDD		74.56	-	89.30	
Design Day HDD's		73.00	66.00	59.00	
Design Day Heat Load Volume -- Mcf per day		5,443.05	-	5,268.77	10,711.82
Anticipated Design Day Volume -- Mcf per day		5,627.42	1,008.23	6,619.03	13,254.68
Interstate					
Mcf per day -- January 2023	Sch. K-1,K-2,K-3	1,026.40	-	-	1,026.40
Irrigation					
Mcf per day -- 2023 Test Year	Sch. K-1,K-2,K-3	45,226.93	1,318.99	128.84	46,674.77
Resale					
Mcf per day -- January 2023	Sch. K-1,K-2,K-3	4,815.26	-	-	4,815.26
Transportation					
Mcf per day -- January 2023	Sch. K-1,K-2,K-3	3,347.94	3,347.94	33,502.89	40,198.77
Gathering					
Mcf per day -- January 2023	Sch. K-1,K-2,K-3	-	-	-	-
Total Non-Jurisdictional		60,043.95	5,675.16	40,250.76	105,969.88 141,636.69

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SUMMARY OF ADJUSTED TEST YEAR BILLING UNITS

ALL ZONES

	Reference	Description	2023		
			Unadjusted	Weather Adj.	Adjusted
JURISDICTIONAL:					
Domestic:					
Mcf	Schedules K-1 to K-9	Weather Adjusted	1,007,056	56,179	1,063,235
# Customers	Schedules K-1 to K-9	Test Year	17,924	-	17,924
Non-Domestic:					
<u>Public Authority</u>					
Mcf	Schedules K-1 to K-9	Weather Adjusted	187,925	13,275	201,200
# Customers	Schedules K-1 to K-9	Test Year	738	-	738
<u>Small Commercial</u>					
Mcf	Schedules K-1 to K-9	Weather Adjusted	355,076	16,588	371,663
# Customers	Schedules K-1 to K-9	Test Year	1,725	-	1,725
<u>Large Commercial</u>					
Mcf	Schedules K-1 to K-9	Weather Adjusted	58,671	2,830	61,501
# Customers	Schedules K-1 to K-9	Test Year	21	-	21
Total Jurisdictional					
Mcf			1,608,728	88,872	1,697,599
# Customers			20,407	-	20,407
NON-JURISDICTIONAL:					
<u>Public Authority</u>					
Mcf	Schedules K-1 to K-9	Weather Adjusted	41,249	1,301	42,551
# Customers	Schedules K-1 to K-9	Test Year	12	0	12
<u>Interstate</u>					
Mcf	Schedules K-1 to K-9	Test Year	517,941	-	517,941
# Customers	Schedules K-1 to K-9	Test Year	14	-	14
<u>Small Commercial</u>					
Mcf	Schedules K-1 to K-9	Weather Adjusted	3,651,532	31,722	3,683,255
# Customers	Schedules K-1 to K-9	Test Year	112	-	112
<u>Large Commercial</u>					
Mcf	Schedules K-1 to K-9	Weather Adjusted	2,879,551	17,548	2,897,099
# Customers	Schedules K-1 to K-9	Test Year	10	(0)	10
<u>Irrigation</u>					
Mcf	Schedules K-1 to K-9	Test Year	17,036,291	-	17,036,291
# Customers	Schedules K-1 to K-9	Test Year	2,942	-	2,942
<u>Resale</u>					
Mcf	Schedules K-1 to K-9	Test Year	1,538,737	-	1,538,737
# Customers	Schedules K-1 to K-9	Test Year	2	-	2
<u>Transportation</u>					
Mcf	Schedules K-1 to K-9	Test Year	13,105,914	-	13,105,914
# Customers	Schedules K-1 to K-9	Test Year	18	0	18
<u>Gathering</u>					
Mcf	Schedules K-1 to K-9	Test Year	209,882	-	209,882
# Customers	Schedules K-1 to K-9	Test Year	3	-	3
<u>Intercompany</u>					
Mcf	Eliminated	Eliminated	603,357	(603,357)	-
# Customers	Eliminated	Eliminated	16	(16)	-
Total Non-Jurisdictional					
Mcf			39,584,455	(552,785)	39,031,669
# Customers			3,130	(16)	3,113
TOTAL ALL ZONES					
Mcf			41,193,182	(463,913)	40,729,269
# Customers			23,537	(16)	23,521

WEST TEXAS GAS UTILITY, LLC
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ADJUSTED TEST YEAR BILLING UNITS

NORTH ZONE

		2023												
Reference		January	February	March	April	May	June	July	August	September	October	November	December	Total
JURISDICTIONAL:														
Domestic:														
Mcf	Schedule K-4	123,314	130,030	80,152	39,768	30,338	16,786	11,866	17,293	13,684	25,032	74,059	104,074	666,395
# Customers	Schedule K-7	9,443	9,377	9,418	9,392	9,383	9,355	9,325	9,343	9,357	9,387	9,462	9,490	9,394
Non-Domestic:														
<u>Public Authority</u>														
Mcf	Schedule K-4	27,586	23,273	14,426	6,371	4,059	1,964	1,350	1,651	1,353	3,372	12,249	21,967	119,622
# Customers	Schedule K-7	382	368	368	369	370	368	368	369	368	370	371	372	370
<u>Small Commercial</u>														
Mcf	Schedule K-4	33,707	34,139	24,066	10,859	7,699	3,829	3,739	(3,619)	12,999	6,187	17,915	31,051	182,571
# Customers	Schedule K-7	962	970	979	972	968	957	953	956	959	964	973	987	967
<u>Large Commercial</u>														
Mcf	Schedule K-4	195	183	140	37	26	2	3	3	2	11	81	188	871
# Customers	Schedule K-7	4	4	5	4	4	4	4	4	4	4	4	4	4
Total Jurisdictional														
Mcf		184,802	187,625	118,784	57,035	42,122	22,580	16,958	15,328	28,038	34,603	104,304	157,280	969,460
# Customers		10,791	10,719	10,770	10,737	10,725	10,684	10,650	10,672	10,688	10,725	10,810	10,853	10,735
NON-JURISDICTIONAL:														
<u>Public Authority</u>														
Mcf	Schedule K-4	4,163	5,918	3,956	2,002	1,370	1,433	1,132	1,260	1,128	1,745	3,269	4,160	31,536
# Customers	Schedule K-7	(4)	6	7	7	7	6	6	7	7	7	7	7	6
<u>Interstate</u>														
Mcf	Schedule K-7	31,818	24,145	39,127	46,424	46,939	20,793	50,572	81,449	66,299	45,792	37,603	26,979	517,941
# Customers	Schedule K-7	15	15	14	15	15	13	13	12	13	14	14	14	14
<u>Small Commercial</u>														
Mcf	Schedule K-4	240,325	222,132	214,518	168,108	255,553	179,734	172,753	205,192	263,715	240,153	266,908	269,793	2,698,884
# Customers	Schedule K-7	74	81	78	75	76	71	69	70	69	77	78	77	75
<u>Large Commercial</u>														
Mcf	Schedule K-4	262,899	255,002	246,990	230,638	232,487	219,283	186,185	219,338	222,616	238,307	248,913	243,159	2,805,817
# Customers	Schedule K-7	6	6	5	6	6	5	5	6	6	7	7	7	6
<u>Irrigation</u>														
Mcf	Schedule K-7	544,204	513,832	1,574,604	2,218,811	1,431,838	632,749	2,123,117	3,202,238	2,104,611	1,201,189	627,337	333,301	16,507,830
# Customers	Schedule K-7	2,096	2,225	2,908	3,053	2,888	2,716	3,005	3,029	3,034	2,719	2,469	1,831	2,664
<u>Resale</u>														
Mcf	Schedule K-7	149,273	119,108	202,577	188,532	96,242	41,770	172,676	188,488	118,945	70,290	103,622	87,214	1,538,737
# Customers	Schedule K-7	3	2	2	2	2	2	2	2	3	3	4	2	2
<u>Transportation</u>														
Mcf	Schedule K-7	103,786	87,419	71,435	41,081	26,828	21,861	(28,113)	15,855	16,265	30,993	57,021	83,686	528,118
# Customers	Schedule K-7	12	12	12	12	12	12	11	9	9	11	11	11	11
<u>Gathering</u>														
Mcf	Schedule K-7	-	1,717	1,702	25,656	24,485	22,911	24,064	23,741	21,833	27,203	21,164	15,406	209,882
# Customers	Schedule K-7	-	2	2	3	3	3	3	3	3	3	3	3	3
<u>Intercompany</u>														
Mcf	Eliminated													
# Customers	Eliminated													
Total Non-Jurisdictional														
Mcf		1,336,468	1,229,273	2,354,909	2,921,252	2,115,742	1,140,534	2,702,384	3,937,562	2,815,412	1,855,672	1,365,839	1,063,698	24,838,746
# Customers		2,202	2,349	3,028	3,173	3,009	2,828	3,114	3,138	3,144	2,841	2,593	1,952	2,781
TOTAL NORTH ZONE														
Mcf		1,521,270	1,416,898	2,473,692	2,978,288	2,157,864	1,163,114	2,719,343	3,952,889	2,843,451	1,890,275	1,470,142	1,220,978	25,808,205
# Customers		12,993	13,068	13,798	13,910	13,734	13,512	13,764	13,810	13,832	13,566	13,403	12,805	13,516

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ADJUSTED TEST YEAR BILLING UNITS

WEST ZONE

		2023												
Reference		January	February	March	April	May	June	July	August	September	October	November	December	Total
JURISDICTIONAL:														
Domestic:														
Mcf	Schedule K-5	51,095	49,713	28,100	18,113	19,040	6,519	8,663	9,788	9,481	19,960	30,327	50,604	301,402
# Customers	Schedule K-8	4,597	4,975	5,067	5,127	5,144	5,195	5,249	5,283	5,337	5,354	5,395	5,472	5,183
Non-Domestic:														
<u>Public Authority</u>														
Mcf	Schedule K-5	6,645	5,370	2,839	1,427	868	601	887	1,462	2,273	1,712	2,657	4,372	31,113
# Customers	Schedule K-8	137	138	138	138	138	137	138	138	138	138	137	142	138
<u>Small Commercial</u>														
Mcf	Schedule K-5	17,903	14,193	9,206	6,111	6,982	3,679	4,095	4,591	4,739	8,555	11,683	12,853	104,592
# Customers	Schedule K-8	685	394	394	399	402	402	403	407	415	421	423	427	431
<u>Large Commercial</u>														
Mcf	Schedule K-5	1,945	2,070	3,250	2,982	3,480	1,762	1,646	1,738	1,126	7,093	2,028	4,455	33,573
# Customers	Schedule K-8	10	10	10	10	10	10	11	11	10	10	10	10	10
Total Jurisdictional														
Mcf		77,587	71,345	43,396	28,632	30,370	12,560	15,291	17,579	17,620	37,320	46,696	72,284	470,680
# Customers		5,429	5,517	5,609	5,674	5,694	5,744	5,801	5,839	5,900	5,923	5,965	6,051	5,762
NON-JURISDICTIONAL:														
<u>Public Authority</u>														
Mcf	Schedule K-5	2,467	2,148	1,100	543	418	58	102	197	174	558	1,048	2,202	11,015
# Customers	Schedule K-8	7	7	6	6	6	5	5	6	6	6	6	6	6
<u>Interstate</u>														
Mcf	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Small Commercial</u>														
Mcf	Schedule K-5	35,747	23,341	26,324	23,470	23,236	23,060	18,539	13,683	10,602	29,195	82,722	68,666	378,586
# Customers	Schedule K-8	43	40	40	37	32	25	24	24	24	39	41	40	34
<u>Large Commercial</u>														
Mcf	Schedule K-5	3,034	2,643	3,181	2,867	3,046	1,523	2,593	1,968	2,170	3,955	3,264	4,668	34,911
# Customers	Schedule K-8	2	2	2	2	2	2	2	2	2	3	3	3	2
<u>Irrigation</u>														
Mcf	Schedule K-8	15,303	11,790	40,039	54,103	39,972	47,619	67,454	89,374	53,794	33,479	16,535	11,971	481,432
# Customers	Schedule K-8	251	245	255	253	251	251	256	250	255	244	238	230	248
<u>Resale</u>														
Mcf	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Transportation</u>														
Mcf	Schedule K-8	89,585	88,800	84,357	67,804	38,733	34,920	41,659	52,201	53,110	54,795	72,128	90,719	768,811
# Customers	Schedule K-8	4	4	4	4	4	4	4	4	4	4	4	4	4
<u>Gathering</u>														
Mcf	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Intercompany</u>														
Mcf	Eliminated	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Eliminated	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Non-Jurisdictional														
Mcf		146,136	128,721	155,002	148,786	105,405	107,180	130,347	157,423	119,851	121,982	175,697	178,226	1,674,755
# Customers		307	298	307	302	295	287	291	286	291	296	292	283	295
TOTAL WEST ZONE														
Mcf		223,723	200,066	198,398	177,418	135,776	119,740	145,637	175,001	137,471	159,302	222,392	250,510	2,145,435
# Customers		5,736	5,815	5,916	5,976	5,989	6,031	6,092	6,125	6,191	6,219	6,257	6,334	6,057

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ADJUSTED TEST YEAR BILLING UNITS

SOUTH ZONE

		2023												
Reference		January	February	March	April	May	June	July	August	September	October	November	December	Total
JURISDICTIONAL:														
Domestic:														
Mcf	Schedule K-6	19,414	16,788	8,319	4,593	3,961	2,313	2,294	1,751	3,236	5,251	10,623	16,895	95,438
# Customers	Schedule K-9	3,371	3,381	3,375	3,359	3,349	3,348	3,347	3,338	3,312	3,316	3,338	3,323	3,346
Non-Domestic:														
<u>Public Authority</u>														
Mcf	Schedule K-6	9,012	8,479	4,187	2,997	2,762	1,736	1,227	2,287	1,627	3,464	5,240	7,447	50,465
# Customers	Schedule K-9	230	230	230	230	230	230	230	230	229	228	228	227	229
<u>Small Commercial</u>														
Mcf	Schedule K-6	10,556	10,386	6,843	5,400	6,391	4,040	5,035	4,968	5,842	6,252	9,090	9,697	84,501
# Customers	Schedule K-9	331	333	330	326	325	324	324	322	321	326	331	333	327
<u>Large Commercial</u>														
Mcf	Schedule K-6	1,938	1,736	1,747	1,261	1,226	1,041	918	1,116	898	2,454	7,086	5,635	27,056
# Customers	Schedule K-9	7	7	7	7	7	7	7	7	7	7	7	7	7
Total Jurisdictional														
Mcf		40,921	37,389	21,096	14,250	14,341	9,130	9,473	10,122	11,602	17,422	32,039	39,673	257,460
# Customers		3,939	3,951	3,942	3,922	3,911	3,909	3,908	3,897	3,869	3,877	3,904	3,890	3,910
NON-JURISDICTIONAL:														
<u>Public Authority</u>														
Mcf	Schedule K-6	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-9	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Interstate</u>														
Mcf	Schedule K-9	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-9	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Small Commercial</u>														
Mcf	Schedule K-6	49,045	45,715	48,772	46,678	43,891	48,528	52,664	52,131	54,322	50,878	58,331	54,831	605,785
# Customers	Schedule K-9	3	3	3	3	4	4	4	4	3	3	3	3	3
<u>Large Commercial</u>														
Mcf	Schedule K-6	15,318	14,802	2,602	623	182	57	1	1	2	376	8,124	14,284	56,371
# Customers	Schedule K-9	2	2	2	2	2	2	1	1	1	2	2	2	2
<u>Irrigation</u>														
Mcf	Schedule K-9	1,142	1,817	2,311	3,417	1,810	5,738	7,888	7,496	8,595	5,440	1,153	223	47,028
# Customers	Schedule K-9	32	33	32	29	30	30	28	30	30	30	26	27	30
<u>Resale</u>														
Mcf	Schedule K-9	0	0	0	0	0	0	0	0	0	0	0	0	0
# Customers	Schedule K-9	0	0	0	0	0	0	0	0	0	0	0	0	0
<u>Transportation</u>														
Mcf	Schedule K-9	1,038,590	965,310	1,005,706	892,993	1,018,672	1,022,764	1,045,685	1,003,523	956,455	1,009,934	968,139	881,216	11,808,984
# Customers	Schedule K-9	3	3	3	3	3	3	3	3	3	3	3	3	3
<u>Gathering</u>														
Mcf	Schedule K-9	0	0	0	0	0	0	0	0	0	0	0	0	0
# Customers	Schedule K-9	0	0	0	0	0	0	0	0	0	0	0	0	0
<u>Intercompany</u>														
Mcf	Eliminated	0	0	0	0	0	0	0	0	0	0	0	0	0
# Customers	Eliminated	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Non-Jurisdictional														
Mcf		1,104,094	1,027,643	1,059,390	943,711	1,064,555	1,077,087	1,106,238	1,063,151	1,019,374	1,066,628	1,035,747	950,554	12,518,169
# Customers		40	41	40	37	39	39	36	38	37	38	34	35	38
TOTAL SOUTH ZONE														
Mcf		1,145,015	1,065,033	1,080,486	957,961	1,078,896	1,086,217	1,115,710	1,073,273	1,030,976	1,084,050	1,067,786	990,227	12,775,629
# Customers		3,979	3,992	3,982	3,959	3,950	3,948	3,944	3,935	3,906	3,915	3,938	3,925	3,948

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WEATHER ADJUSTMENTS

NORTH ZONE -- Amarillo

	2023												Total
	January	February	March	April	May	June	July	August	September	October	November	December	
HEATING DEGREE DAYS:													
2023	748	589	484	264	28	5	-	-	3	198	448	671	3,438
10-Year Average	805	687	451	248	78	3	-	-	17	209	500	738	3,737
JURISDICTIONAL:													
Domestic:													
<u>Mcf</u>													
Mcf	114,649	120,818	74,935	37,778	29,101	16,630	11,866	17,095	13,684	23,030	69,335	96,953	625,873
# Customers	9,443	9,377	9,418	9,392	9,383	9,355	9,325	9,343	9,357	9,387	9,462	9,490	9,394
Use per Customer	12.14	12.88	7.96	4.02	3.10	1.78	1.27	1.83	1.46	2.45	7.33	10.22	66.62
Base Use per Customer	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59		1.59	1.59	17.44
Weather Sensitive Use	10.56	11.30	6.37	2.44	1.52	0.19	-	0.24	-	2.45	5.74	8.63	49.44
Weather Adjusted Use	11.47	12.28	6.92	2.65	1.65	0.21	-	0.27	-	2.67	6.24	9.38	53.74
Weather Adjusted Mcf	123,314	130,030	80,152	39,768	30,338	16,786	11,866	17,293	13,684	25,032	74,059	104,074	666,395
Non-Domestic:													
<u>Public Authority</u>													
Mcf	25,510	21,538	13,398	5,988	3,862	1,964	1,350	1,645	1,353	3,229	11,397	20,338	111,572
# Customers	382	368	368	369	370	368	368	369	368	370	371	372	370
Use per Customer	66.78	58.53	36.41	16.23	10.44	5.34	3.67	4.46	3.68	8.73	30.72	54.67	301.34
Base Use per Customer	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	51.42
Weather Sensitive Use	62.50	54.24	32.12	11.94	6.15	-	-	0.17	-	4.44	26.43	50.39	248.39
Weather Adjusted Use	67.93	58.96	34.92	12.98	6.69	-	-	0.19	-	4.83	28.73	54.77	269.99
Weather Adjusted Mcf	27,586	23,273	14,426	6,371	4,059	1,964	1,350	1,651	1,353	3,372	12,249	21,967	119,622
<u>Small Commercial</u>													
Mcf	31,337	31,737	22,473	10,320	7,411	3,829	3,739	(3,619)	12,285	6,019	16,812	28,902	171,244
# Customers	962	970	979	972	968	957	953	956	959	964	973	987	967
Use per Customer	32.58	32.72	22.95	10.62	7.66	4.00	3.92	(3.79)	12.81	6.24	17.28	29.28	177.15
Base Use per Customer	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	50.85
Weather Sensitive Use	28.34	28.48	18.72	6.38	3.42	-	-	-	8.57	2.01	13.04	25.05	134.00
Weather Adjusted Use	30.80	30.96	20.34	6.93	3.72	-	-	-	9.32	2.18	14.17	27.22	145.65
Weather Adjusted Mcf	33,707	34,139	24,066	10,859	7,699	3,829	3,739	(3,619)	12,999	6,187	17,915	31,051	182,571
<u>Large Commercial</u>													
Mcf	179	169	129	35	24	2	3	3	2	11	75	173	804
# Customers	4	4	5	4	4	4	4	4	4	4	4	4	4
Use per Customer	44.85	42.13	25.82	8.63	6.05	0.40	0.80	0.75	0.50	2.68	18.70	43.20	196.85
Base Use per Customer	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	7.35
Weather Sensitive Use	44.24	41.51	25.21	8.01	5.44	-	-	-	-	2.06	18.09	42.59	187.15
Weather Adjusted Use	48.08	45.12	27.40	8.71	5.91	-	-	-	-	2.24	19.66	46.29	203.42
Weather Adjusted Mcf	195	183	140	37	26	2	3	3	2	11	81	188	871
NON-JURISDICTIONAL:													
<u>Public Authority</u>													
Mcf	4,163	5,537	3,747	1,950	1,368	1,433	1,132	1,260	1,128	1,713	3,115	3,935	30,480
# Customers	(4)	6	7	7	7	6	6	7	7	7	7	7	6
Use per Customer	(1,040.68)	922.85	535.33	278.56	195.41	238.87	188.60	180.01	161.11	244.66	445.03	562.09	5,293.89
Base Use per Customer	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	2,305.79
Weather Sensitive Use	-	730.70	343.18	86.41	3.27	-	-	-	-	52.51	252.88	369.94	1,838.88
Weather Adjusted Use	-	794.23	373.02	93.92	3.55	-	-	-	-	57.07	274.87	402.10	1,998.75
Weather Adjusted Mcf	4,163	5,918	3,956	2,002	1,370	1,433	1,132	1,260	1,128	1,745	3,269	4,160	31,536
<u>Small Commercial</u>													
Mcf	238,441	222,132	214,518	168,108	252,919	179,734	172,753	205,192	258,788	238,985	263,835	266,254	2,681,659
# Customers	74	81	78	75	76	71	69	70	69	77	78	77	75
Use per Customer	3,222.17	2,742.37	2,750.23	2,241.44	3,327.89	2,531.46	2,503.66	2,931.32	3,750.55	3,103.70	3,382.49	3,457.84	35,955.20
Base Use per Customer	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	35,150.99
Weather Sensitive Use	292.92	-	-	-	398.64	-	-	-	821.30	174.45	453.25	528.59	2,669.16
Weather Adjusted Use	318.39	-	-	-	433.30	-	-	-	892.71	189.62	492.65	574.55	2,901.21
Weather Adjusted Mcf	240,325	222,132	214,518	168,108	255,553	179,734	172,753	205,192	263,715	240,153	266,908	269,793	2,698,884
<u>Large Commercial</u>													
Mcf	260,437	253,173	242,706	230,638	232,458	219,283	186,185	219,338	222,616	238,307	248,913	243,159	2,797,214
# Customers	6	6	5	6	6	5	5	6	6	7	7	7	6
Use per Customer	43,406.23	42,195.42	48,541.28	38,439.63	38,743.00	43,856.58	37,237.04	36,556.33	37,102.68	34,043.90	35,559.06	34,737.06	466,202.40
Base Use per Customer	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	464,257.91
Weather Sensitive Use	4,718.07	3,507.26	9,853.12	-	54.84	-	-	-	-	-	-	-	18,133.29
Weather Adjusted Use	5,128.26	3,812.18	10,709.75	-	59.61	-	-	-	-	-	-	-	19,709.80
Weather Adjusted Mcf	262,899	255,002	246,990	230,638	232,487	219,283	186,185	219,338	222,616	238,307	248,913	243,159	2,805,817

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WEATHER ADJUSTMENTS

711 456.2 239.9 81.7 11.7 0 0 0 5.9 91 320.7 506.7

WEST ZONE -- Midland-Odessa

	2023												Total
	January	February	March	April	May	June	July	August	September	October	November	December	
HEATING DEGREE DAYS:													
2023	550	448	250	105	1	-	-	-	-	92	325	487	2,258
10-Year Average	605	456	240	82	12	-	-	-	6	91	321	507	2,319
JURISDICTIONAL:													
Domestic:													
<u>Mcf</u>													
Mcf	49,956	48,704	27,582	17,858	18,761	6,519	8,663	9,758	9,461	19,667	29,764	49,514	296,207
# Customers	4,597	4,975	5,067	5,127	5,144	5,195	5,249	5,283	5,337	5,354	5,395	5,472	5,183
Use per Customer	10.87	9.79	5.44	3.48	3.65	1.25	1.65	1.85	1.77	3.67	5.52	9.05	57.15
Base Use per Customer	1.63	2.24	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	20.18
Weather Sensitive Use	9.24	7.55	3.81	1.85	2.02	-	-	0.22	0.14	2.04	3.89	7.42	38.17
Weather Adjusted Use	9.48	7.76	3.91	1.90	2.07	-	-	0.22	0.15	2.10	3.99	7.62	39.20
Weather Adjusted Mcf	51,095	49,713	28,100	18,113	19,040	6,519	8,663	9,788	9,481	19,960	30,327	50,604	301,402
<u>Non-Domestic:</u>													
<u>Public Authority</u>													
Mcf	6,505	5,264	2,799	1,424	868	601	887	1,457	2,248	1,701	2,621	4,293	30,667
# Customers	137	138	138	138	138	137	138	138	138	138	137	142	138
Use per Customer	47.48	38.14	20.28	10.32	6.29	4.39	6.42	10.56	16.29	12.33	19.13	30.23	222.09
Base Use per Customer	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	112.98
Weather Sensitive Use	38.06	28.73	10.87	0.90	-	-	-	1.15	6.87	2.91	9.72	20.82	120.02
Weather Adjusted Use	39.09	29.50	11.16	0.92	-	-	-	1.18	7.06	2.99	9.98	21.37	123.25
Weather Adjusted Mcf	6,645	5,370	2,839	1,427	868	601	887	1,462	2,273	1,712	2,657	4,372	31,113
<u>Small Commercial</u>													
Mcf	17,623	13,930	9,074	6,061	6,910	3,679	4,095	4,591	4,729	8,447	11,494	12,635	103,268
# Customers	685	394	394	399	402	402	403	407	415	421	423	427	431
Use per Customer	25.73	35.35	23.03	15.19	17.19	9.15	10.16	11.28	11.40	20.06	27.17	29.59	239.60
Base Use per Customer	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	125.97
Weather Sensitive Use	15.23	24.86	12.53	4.69	6.69	-	-	-	0.90	9.57	16.68	19.09	110.24
Weather Adjusted Use	15.64	25.52	12.87	4.82	6.87	-	-	-	0.92	9.82	17.12	19.60	113.19
Weather Adjusted Mcf	17,903	14,193	9,206	6,111	6,982	3,679	4,095	4,591	4,739	8,555	11,683	12,853	104,592
<u>Large Commercial</u>													
Mcf	1,933	2,055	3,204	2,943	3,428	1,762	1,646	1,738	1,126	6,946	2,014	4,377	33,172
# Customers	10	10	10	10	10	10	11	11	10	10	10	10	10
Use per Customer	193.29	205.46	320.41	294.27	342.81	176.20	149.65	157.96	112.61	694.61	201.40	437.72	3,262.78
Base Use per Customer	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	1,789.28
Weather Sensitive Use	44.18	56.35	171.30	145.16	193.70	-	-	-	-	545.50	52.29	288.61	1,497.11
Weather Adjusted Use	45.37	57.87	175.90	149.06	198.90	-	-	-	-	560.14	53.70	296.36	1,537.29
Weather Adjusted Mcf	1,945	2,070	3,250	2,982	3,480	1,762	1,646	1,738	1,126	7,093	2,028	4,455	33,573
NON-JURISDICTIONAL:													
<u>Public Authority</u>													
Mcf	2,407	2,096	1,075	532	411	58	102	196	173	547	1,025	2,148	10,769
# Customers	7	7	6	6	6	5	5	6	6	6	6	6	6
Use per Customer	343.80	299.39	179.17	88.73	68.53	11.58	20.44	32.63	28.88	91.10	170.75	358.02	1,794.88
Base Use per Customer	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	280.61
Weather Sensitive Use	320.42	276.00	155.78	65.35	45.15	-	-	9.25	5.50	67.72	147.37	334.63	1,427.16
Weather Adjusted Use	329.02	283.41	159.96	67.10	46.36	-	-	9.50	5.65	69.53	151.32	343.61	1,465.46
Weather Adjusted Mcf	2,467	2,148	1,100	543	418	58	102	197	174	558	1,048	2,202	11,015
<u>Small Commercial</u>													
Mcf	35,572	23,341	26,324	23,470	23,193	22,899	18,539	13,683	10,602	29,120	81,284	67,578	375,603
# Customers	43	40	40	37	32	25	24	24	24	39	41	40	34
Use per Customer	827.25	583.52	658.11	634.31	724.79	915.95	772.44	570.12	441.77	746.66	1,982.52	1,689.44	11,020.14
Base Use per Customer	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	8,100.83
Weather Sensitive Use	152.18	-	-	-	49.72	240.88	-	-	-	71.59	1,307.46	1,014.37	2,836.20
Weather Adjusted Use	156.27	-	-	-	51.05	247.35	-	-	-	73.52	1,342.54	1,041.59	2,912.32
Weather Adjusted Mcf	35,747	23,341	26,324	23,470	23,236	23,060	18,539	13,683	10,602	29,195	82,722	68,666	378,586
<u>Large Commercial</u>													
Mcf	3,008	2,628	3,152	2,846	3,020	1,523	2,593	1,968	2,170	3,932	3,259	4,627	34,726
# Customers	2	2	2	2	2	2	2	2	2	3	3	3	2
Use per Customer	1,504.10	1,314.00	1,576.05	1,422.95	1,510.15	761.45	1,296.45	983.80	1,085.15	1,310.73	1,086.40	1,542.23	14,369.50
Base Use per Customer	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	12,380.55
Weather Sensitive Use	472.39	282.29	544.34	391.24	478.44	-	-	-	-	279.02	54.69	510.52	3,012.92
Weather Adjusted Use	485.07	289.86	558.95	401.74	491.28	-	-	-	-	286.51	56.16	524.22	3,093.78
Weather Adjusted Mcf	3,034	2,643	3,181	2,867	3,046	1,523	2,593	1,968	2,170	3,955	3,264	4,668	34,911

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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WEATHER ADJUSTMENTS

SOUTH ZONE -- San Antonio Area

	2023												
	January	February	March	April	May	June	July	August	September	October	November	December	Total
HEATING DEGREE DAYS:													
2023	252	247	83	29	-	-	-	-	-	36	173	243	1,063
10-Year Average	371	275	108	26	1	-	-	-	-	29	163	286	1,259
JURISDICTIONAL:													
Domestic:													
Mcf	16,759	14,643	7,395	4,248	3,714	2,313	2,294	1,751	3,097	4,799	9,336	14,627	84,977
# Customers	3,371	3,381	3,375	3,359	3,349	3,348	3,347	3,338	3,312	3,316	3,338	3,323	3,346
Use per Customer	4.97	4.33	2.19	1.26	1.11	0.69	0.69	0.52	0.94	1.45	2.80	4.40	25.39
Base Use per Customer	0.71	0.90	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	8.70
Weather Sensitive Use	4.26	3.43	1.48	0.56	0.40	-	-	-	0.23	0.74	2.09	3.69	16.88
Weather Adjusted Use	5.05	4.07	1.76	0.66	0.47	-	-	-	0.27	0.87	2.47	4.38	20.00
Weather Adjusted Mcf	19,414	16,788	8,319	4,593	3,961	2,313	2,294	1,751	3,236	5,251	10,623	16,895	95,438
Non-Domestic:													
Public Authority													
Mcf	7,871	7,422	3,799	2,794	2,596	1,736	1,227	2,195	1,627	3,187	4,685	6,547	45,686
# Customers	230	230	230	230	230	230	230	230	229	228	228	227	229
Use per Customer	34.22	32.27	16.52	12.15	11.29	7.55	5.33	9.54	7.10	13.98	20.55	28.84	199.21
Base Use per Customer	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	88.58
Weather Sensitive Use	26.84	24.89	9.14	4.77	3.91	-	-	2.16	-	6.59	13.17	21.46	112.92
Weather Adjusted Use	31.80	29.48	10.82	5.65	4.63	-	-	2.56	-	7.81	15.60	25.42	133.79
Weather Adjusted Mcf	9,012	8,479	4,187	2,997	2,762	1,736	1,227	2,287	1,627	3,464	5,240	7,447	50,465
Small Commercial													
Mcf	9,700	9,561	6,563	5,335	6,170	4,040	5,035	4,968	5,697	6,055	8,462	8,979	80,564
# Customers	331	333	330	326	325	324	324	322	321	326	331	333	327
Use per Customer	29.30	28.71	19.89	16.37	18.98	12.47	15.54	15.43	17.75	18.57	25.56	26.96	246.25
Base Use per Customer	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	183.55
Weather Sensitive Use	14.01	13.41	4.59	1.07	3.69	-	-	-	2.45	3.28	10.27	11.67	64.44
Weather Adjusted Use	16.60	15.89	5.44	1.27	4.37	-	-	-	2.90	3.88	12.17	13.82	76.35
Weather Adjusted Mcf	10,556	10,386	6,843	5,400	6,391	4,040	5,035	4,968	5,842	6,252	9,090	9,697	84,501
Large Commercial													
Mcf	1,791	1,620	1,629	1,219	1,190	1,041	918	1,116	898	2,227	6,136	4,911	24,695
# Customers	7	7	7	7	7	7	7	7	7	7	7	7	7
Use per Customer	255.84	231.47	232.76	174.13	170.01	148.77	131.14	159.37	128.24	318.07	876.57	701.53	3,527.91
Base Use per Customer	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	1,702.59
Weather Sensitive Use	113.96	89.59	90.88	32.25	28.13	-	-	-	-	176.19	734.69	559.65	1,825.33
Weather Adjusted Use	135.02	106.14	107.67	38.20	33.33	-	-	-	-	208.74	870.43	663.05	2,162.58
Weather Adjusted Mcf	1,938	1,736	1,747	1,261	1,226	1,041	918	1,116	898	2,454	7,086	5,635	27,056
NON-JURISDICTIONAL:													
Public Authority													
Mcf													
# Customers													
Use per Customer													
Base Use per Customer													
Weather Sensitive Use													
Weather Adjusted Use													
Weather Adjusted Mcf													
Small Commercial													
Mcf	47,921	45,111	47,691	45,924	43,891	48,528	52,664	52,131	52,376	49,469	55,760	52,805	594,271
# Customers	3	3	3	3	4	4	4	4	3	3	3	3	3
Use per Customer	15,973.77	15,036.93	15,896.97	15,307.93	10,972.75	12,131.95	13,165.95	13,032.85	17,458.53	16,489.70	18,586.60	17,601.77	178,281.18
Base Use per Customer	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	167,367.85
Weather Sensitive Use	2,026.45	1,089.61	1,949.65	1,360.61	-	-	-	-	3,511.21	2,542.38	4,639.28	3,654.45	20,773.63
Weather Adjusted Use	2,400.85	1,290.93	2,309.86	1,612.00	-	-	-	-	4,159.94	3,012.11	5,496.43	4,329.64	24,611.77
Weather Adjusted Mcf	49,045	45,715	48,772	46,678	43,891	48,528	52,664	52,131	54,322	50,878	58,331	54,831	605,785
Large Commercial													
Mcf	12,931	12,497	2,199	528	156	57	1	1	2	320	6,860	12,059	47,610
# Customers	2	2	2	2	2	2	1	1	1	2	2	2	2
Use per Customer	6,465.70	6,248.25	1,099.25	264.00	78.15	28.55	1.00	1.00	2.00	159.85	3,430.00	6,029.35	27,205.83
Base Use per Customer	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	97.65
Weather Sensitive Use	6,457.56	6,240.11	1,091.11	255.86	70.01	-	-	-	-	151.71	3,421.86	6,021.21	23,709.45
Weather Adjusted Use	7,650.66	7,393.04	1,292.71	303.14	82.95	-	-	-	-	179.74	4,054.09	7,133.69	28,090.01
Weather Adjusted Mcf	15,318	14,802	2,602	623	182	57	1	1	2	376	8,124	14,284	56,371

UNADJUSTED TEST YEAR BILLING UNITS

WEST ZONE

	2023												Total
	January	February	March	April	May	June	July	August	September	October	November	December	
JURISDICTIONAL:													
Domestic:													
Mcf	49,956	48,704	27,582	17,858	18,761	6,519	8,663	9,758	9,461	19,667	29,764	49,514	296,207
# Customers	4,597	4,975	5,067	5,127	5,144	5,195	5,249	5,283	5,337	5,354	5,395	5,472	5,183
Non-Domestic:													
<u>Public Authority</u>													
Mcf	6,505	5,264	2,799	1,424	868	601	887	1,457	2,248	1,701	2,621	4,293	30,667
# Customers	137	138	138	138	138	137	138	138	138	138	137	142	138
<u>Small Commercial</u>													
Mcf	17,623	13,930	9,074	6,061	6,910	3,679	4,095	4,591	4,729	8,447	11,494	12,635	103,268
# Customers	685	394	394	399	402	402	403	407	415	421	423	427	431
<u>Large Commercial</u>													
Mcf	1,933	2,055	3,204	2,943	3,428	1,762	1,646	1,738	1,126	6,946	2,014	4,377	33,172
# Customers	10	10	10	10	10	10	11	11	10	10	10	10	10
Total Jurisdictional													
Mcf	76,016	69,952	42,659	28,285	29,968	12,560	15,291	17,544	17,565	36,762	45,894	70,819	463,313
# Customers	5,429	5,517	5,609	5,674	5,694	5,744	5,801	5,839	5,900	5,923	5,965	6,051	5,762
NON-JURISDICTIONAL:													
<u>Public Authority</u>													
Mcf	2,407	2,096	1,075	532	411	58	102	196	173	547	1,025	2,148	10,769
# Customers	7	7	6	6	6	5	5	6	6	6	6	6	6
<u>Interstate</u>													
Mcf													
# Customers													
<u>Small Commercial</u>													
Mcf	35,572	23,341	26,324	23,470	23,193	22,899	18,539	13,683	10,602	29,120	81,284	67,578	375,603
# Customers	43	40	40	37	32	25	24	24	24	39	41	40	34
<u>Large Commercial</u>													
Mcf	3,008	2,628	3,152	2,846	3,020	1,523	2,593	1,968	2,170	3,932	3,259	4,627	34,726
# Customers	2	2	2	2	2	2	2	2	2	3	3	3	2
<u>Irrigation</u>													
Mcf	15,303	11,790	40,039	54,103	39,972	47,619	67,454	89,374	53,794	33,479	16,535	11,971	481,432
# Customers	251	245	255	253	251	251	256	250	255	244	238	230	248
<u>Resale</u>													
Mcf													
# Customers													
<u>Transportation</u>													
Mcf	89,585	88,800	84,357	67,804	38,733	34,920	41,659	52,201	53,110	54,795	72,128	90,719	768,811
# Customers	4	4	4	4	4	4	4	4	4	4	4	4	4
<u>Gathering</u>													
Mcf													
# Customers													
<u>Intercompany</u>													
Mcf													
# Customers													
Total Non-Jurisdictional													
Mcf	145,874	128,654	154,948	148,754	105,330	107,018	130,347	157,421	119,850	121,874	174,230	177,042	1,671,342
# Customers	307	298	307	302	295	287	291	286	291	296	292	283	295
TOTAL WEST ZONE													
Mcf	221,890	198,606	197,606	177,039	135,298	119,579	145,637	174,965	137,414	158,635	220,124	247,861	2,134,655
# Customers	5,736	5,815	5,916	5,976	5,989	6,031	6,092	6,125	6,191	6,219	6,257	6,334	6,057
Check:	221,890	198,606	197,606	177,039	135,298	119,579	145,637	174,965	137,414	158,635	220,124	247,861	2,134,655
	5,736	5,815	5,916	5,976	5,989	6,031	6,092	6,125	6,191	6,219	6,257	6,334	6,057
Irrigation													
2019 Mcf	6,301	18,465	26,636	61,941	51,707	49,809	85,931	98,029	59,979	32,629	7,221	4,040	502,687
# Customers	334	332	349	352	352	343	349	350	341	322	301	293	335
2020 Mcf	7,642	6,834	21,985	46,665	61,847	67,979	99,496	104,602	67,209	40,007	12,120	12,341	548,725
# Customers	303	305	293	307	313	310	313	321	317	301	297	294	306
2021 Mcf	11,147	12,711	36,347	53,281	60,675	48,197	47,691	72,590	76,577	40,644	27,792	8,648	496,299
# Customers	287	279	296	303	291	277	266	285	290	280	267	254	281
2022 Mcf	5,227	13,405	42,403	65,136	62,823	66,309	87,406	72,386	34,354	17,284	7,489	4,233	478,455
# Customers	256	263	269	278	266	261	260	260	245	241	238	238	256
2023 Mcf	15,303	11,790	40,039	54,103	39,972	47,619	67,454	89,374	53,794	33,479	16,535	11,971	481,432
# Customers	251	245	255	253	251	251	256	250	255	244	238	230	248

WEST TEXAS GAS UTILITY, LLC
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UNADJUSTED TEST YEAR BILLING UNITS

SOUTH ZONE

	2023												Total
	January	February	March	April	May	June	July	August	September	October	November	December	
JURISDICTIONAL:													
Domestic:													
Mcf	16,759	14,643	7,395	4,248	3,714	2,313	2,294	1,751	3,097	4,799	9,336	14,627	84,977
# Customers	3,371	3,381	3,375	3,359	3,349	3,348	3,347	3,338	3,312	3,316	3,338	3,323	3,346
Non-Domestic:													
<u>Public Authority</u>													
Mcf	7,871	7,422	3,799	2,794	2,596	1,736	1,227	2,195	1,627	3,187	4,685	6,547	45,686
# Customers	230	230	230	230	230	230	230	230	229	228	228	227	229
<u>Small Commercial</u>													
Mcf	9,700	9,561	6,563	5,335	6,170	4,040	5,035	4,968	5,697	6,055	8,462	8,979	80,564
# Customers	331	333	330	326	325	324	324	322	321	326	331	333	327
<u>Large Commercial</u>													
Mcf	1,791	1,620	1,629	1,219	1,190	1,041	918	1,116	898	2,227	6,136	4,911	24,695
# Customers	7	7	7	7	7	7	7	7	7	7	7	7	7
Total Jurisdictional													
Mcf	36,121	33,246	19,386	13,597	13,670	9,130	9,473	10,030	11,318	16,267	28,619	35,064	235,922
# Customers	3,939	3,951	3,942	3,922	3,911	3,909	3,908	3,897	3,869	3,877	3,904	3,890	3,910
NON-JURISDICTIONAL:													
<u>Public Authority</u>													
Mcf													
# Customers													
<u>Interstate</u>													
Mcf													
# Customers													
<u>Small Commercial</u>													
Mcf	47,921	45,111	47,691	45,924	43,891	48,528	52,664	52,131	52,376	49,469	55,760	52,805	594,271
# Customers	3	3	3	3	4	4	4	4	3	3	3	3	3
<u>Large Commercial</u>													
Mcf	12,931	12,497	2,199	528	156	57	1	1	2	320	6,860	12,059	47,610
# Customers	2	2	2	2	2	2	1	1	1	2	2	2	2
<u>Irrigation</u>													
Mcf	1,142	1,817	2,311	3,417	1,810	5,738	7,888	7,496	8,595	5,440	1,153	223	47,028
# Customers	32	33	32	29	30	30	28	30	30	30	26	27	30
<u>Resale</u>													
Mcf													
# Customers													
<u>Transportation</u>													
Mcf	1,038,590	965,310	1,005,706	892,993	1,018,672	1,022,764	1,045,685	1,003,523	956,455	1,009,934	968,139	881,216	11,808,984
# Customers	3	3	3	3	3	3	3	3	3	3	3	3	3
<u>Gathering</u>													
Mcf													
# Customers													
<u>Intercompany</u>													
Mcf													
# Customers													
Total Non-Jurisdictional													
Mcf	1,100,584	1,024,734	1,057,906	942,862	1,064,529	1,077,087	1,106,238	1,063,151	1,017,427	1,065,162	1,031,911	946,303	12,497,894
# Customers	40	41	40	37	39	39	36	38	37	38	34	35	38
TOTAL SOUTH ZONE													
Mcf	1,136,706	1,057,980	1,077,292	956,459	1,078,199	1,086,217	1,115,710	1,073,181	1,028,746	1,081,429	1,060,530	981,367	12,733,815
# Customers	3,979	3,992	3,982	3,959	3,950	3,948	3,944	3,935	3,906	3,915	3,938	3,925	3,948
Check:													
Mcf	1,136,706	1,057,980	1,077,292	956,459	1,078,199	1,086,217	1,115,710	1,073,181	1,028,746	1,081,429	1,060,530	981,367	12,733,815
# Customers	3,979	3,992	3,982	3,959	3,950	3,948	3,944	3,935	3,906	3,915	3,938	3,925	3,948
Irrigation													
2019 Mcf	5,295	5,009	7,983	5,268	4,763	6,615	5,008	11,529	7,139	6,136	3,580	3,841	72,166
# Customers	38	40	44	38	40	43	39	39	35	34	32	37	38
2020 Mcf	3,891	2,629	4,101	3,710	4,680	6,585	10,041	10,130	9,036	11,027	4,862	3,420	74,112
# Customers	34	36	36	39	37	38	36	34	34	35	32	36	36
2021 Mcf	778	1,096	4,887	7,777	2,008	5,783	2,910	7,763	10,037	6,299	4,329	4,955	58,623
# Customers	32	34	46	42	31	40	34	34	35	34	32	32	36
2022 Mcf	2,805	3,893	8,787	11,523	8,737	12,745	12,076	6,809	8,294	5,314	2,803	633	84,418
# Customers	33	37	40	42	39	39	37	38	33	34	32	28	36
2023 Mcf	1,142	1,817	2,311	3,417	1,810	5,738	7,888	7,496	8,595	5,440	1,153	223	47,028
# Customers	32	33	32	29	30	30	28	30	30	30	26	27	30

SCHEDULE WORKPAPERS

Schedule Workpapers are voluminous and are being provided in electronic format.

TESTIMONY WORKPAPERS

Testimony Workpapers are voluminous and are being provided in electronic format.

Sec. 22.012. RESIGNATION OF ELECTED OR APPOINTED MUNICIPAL OFFICER. A municipal officer elected or appointed under this chapter may resign by submitting the resignation in writing to the governing body of the municipality. The resignation is subject to the approval and acceptance of the governing body. However, a person who is appointed by the mayor may submit the written resignation to the mayor for the mayor's action.

Sec. 22.005. OATH FOR ELECTED OR APPOINTED OFFICER. (a) A person who is elected or appointed to a municipal office under this code must take and sign the official oath of office before beginning to perform the duties of the office.

(b) The governing body of the municipality by ordinance may require a municipal officer to take any additional oath that the governing body considers best calculated to secure the faithful performance of the officer's duties.

Sec. 22.010. FILLING VACANCY ON GOVERNING BODY OR IN OTHER MUNICIPAL OFFICE. (a) If for any reason a single vacancy exists on the governing body of the municipality, a majority of the remaining members who are present and voting, excluding the mayor, may fill the vacancy by appointment unless an election to fill the vacancy is required by Section 11, Article XI, Texas Constitution. The mayor may vote on the appointment only if there is a tie.

(a-1) A person serving as a member of the governing body is not, because of that service, ineligible to be appointed to fill a vacancy in the office of mayor of the municipality, but the person may not vote on the person's own appointment.

(b) The person appointed to fill the vacancy serves until the next regular municipal election.

(c) In lieu of appointing a person to fill a vacancy on the governing body, a special election may be ordered to elect a person to fill the vacancy.

(d) If two or more vacancies on the governing body exist at the same time, a special election shall be ordered to fill the vacancies.

(d-1) A member of the governing body is ineligible to vote to fill a vacancy on the governing body by special election after resigning from the governing body.

(e) If a vacancy exists in any other municipal office, the mayor or acting mayor shall appoint a person to fill the vacancy, subject to confirmation by the governing body.

Sec. 22.032. QUALIFICATIONS OF MEMBERS OF GOVERNING BODY.

(a) To be eligible for the office of mayor of the municipality, a person must be a registered voter and must have resided within the municipal limits for at least the 12 months preceding the election day. For purposes of this subsection, residency in an area while the area was not within the municipal limits is considered as residency within the limits if the area is a part of the municipality on election day.

(b) To be eligible for the office of alderman of the municipality, a person must be a registered voter and must reside on election day in the ward from which the person may be elected.

Exhibit A

All text which is underlined denotes addition of new text. All text which is ~~stricken through~~ denotes removal of existing text. All other text is existing, unchanged text. Any existing text which has been omitted shall be considered unchanged. All text which is both between braces { } and *italicized*, is for document organization and reference only and is not intended to be adopted. The Code of Ordinances of City of La Vernia, Texas, Chapter 38 Zoning is hereby amended as follows:

{Amendments to Sec.38-104. Definitions}

Sec. 38-104. Definitions.

~~*Antique shop* means a retail establishment engaged in the selling of works of art, furniture or other artifacts of an earlier period, with all sales and storage occurring inside a building.~~

~~*Arts and crafts store* means a retail store or establishment/open area offering a wide variety of merchandise used for various arts and crafts.~~

Elderly Care Facility means housing and care facilities generally for elderly individuals, including assisted living, continuing care facility, hospice, nursing home, rest home, respite care, and retirement housing.

Flea Market means an indoor or outdoor commercial activity, not including shopping centers, individual retail operations, or sales conducted by a nonprofit or charitable organization, that is open to the general public and composed of multiple separate stalls, booths, tables, or other designated areas or spaces for the purpose of display and sale, exchange, or barter of merchandise. This does not include garage sales.

~~*Florist* means an establishment displaying and selling plants, flowers, floral supplies, and similar items.~~

Servant's/caretaker's/Guard's residence means an accessory building or a portion of an accessory building located on the same lot or grounds with the main building, or a portion of the main building, containing not more than one kitchen and used as living quarters for a person or persons employed on the premises for security purposes for not less than 50 percent of his/her actual working time, and not otherwise used or designed as a separate place of abode.

~~*Handcraft shop* means a specialty retail shop that supplies items necessary for arts and projects created by hand (e.g., weaving, needlepoint, wood work; stain glass work; porcelain, etc.)~~

Health club or gymnasium means a service establishment where athletic facilities such as handball, swimming, track, exercise devices, etc., are provided and may in addition include a whirlpool, sauna, ~~or~~ massage service, or similar amenities for members ~~who shall register each time they utilize the club.~~

Hotel or motel ~~motor hotel or motor lodge~~ means a building or buildings, including individual cabins or cottages, in which lodging is provided and offered to the public for

compensation, and which is open to transient guests ~~a building or group of buildings designed for and occupied as a temporary dwelling place, providing four or more room units for compensation. Units provided for the customers and where the operation is supervised by a person in charge at all hours.~~ A motel, motor hotel, or motor lodge, and which may incorporate restaurants, clubrooms, banquet halls, ballrooms and meeting rooms as accessory uses.

~~Household appliance service and repair means the maintenance and rehabilitation of appliances customarily used in the home including but not limited to washing and drying machines, refrigerators, dishwashers, trash compactors, ovens and ranges, kitchen appliances, and vacuum cleaners.~~

Mixed Use Residential. A building which contains dwellings located above the ground floor or in the rear of an institutional, civic, office, commercial, or retail use.

Office, Medical & Professional means the use of a building or portions of a building for transacting the affairs of a business, profession, service, industry, or government, including but not limited to credit agencies, brokerage services, computer programming and data processing, consulting, engineering, architecture, or similar professional services, health services, insurance, real estate, or legal services, medical offices, travel agency, or other similar professional services with no, or only minimal accessory, retail sales of merchandise and no outdoor sales, service, or storage.

Places of Assembly means a building or site used for the gathering of persons for purposes such as civic, social, recreational, religious, or educational functions. Examples of places of assembly include, but are not limited to, meeting halls and churches or other places of worship.

Renewable Energy System, Commercial means any mechanism or device designed for the purpose of converting wind or solar energy into electrical or mechanical power for the purpose of commercial sale and transmission off-site. This land use specifically excludes small wind energy systems and individual solar energy systems.

Residential Amenity Building means a building that is not a dwelling unit within a residential subdivision or apartment complex that is not for dwelling purposes that houses various amenities, including meeting rooms, recreational and fitness facilities, game rooms, swimming pools, and similar amenities for the exclusive use of residents and their guests.

Retail Shops & Stores means a place of business devoted primarily to the sale, rental, or servicing of goods or commodities which are normally delivered or provided on the premises to a consumer, including but not limited to sale, service, or repair of antiques, appliances, arts and crafts, bicycles, books, computers, flowers, general merchandise, handcrafts, medical supplies, secondhand furniture, clothing, or other goods.

~~Secondhand store, furniture or clothing, means an establishment offering for sale used merchandise, with the storage and display of such items wholly contained inside a building or structure.~~

Shops, office, storage area of public or private utility means the pole yard, or maintenance yard, ~~and/or administrative offices~~ of a municipality or franchised utility.

{Amendments to Sec.38-302. Permitted use charts}

Sec. 38-302. Permitted use charts.

(a) *Key to tables.* The following shall be the key to the tables in subsections (b) through (h) of this section:

Legend

Symbol	Definition
P	Use is permitted in the district indicated
S	Use is permitted in the district indicated upon approval of a specific use permit
(none)	Use is prohibited in the district indicated

(b) *Accessory and incidental uses.*

RA	R-1	R-2	MH	Type of Use:	GP	C-1	C-B	C-2	I	H	PI
P	P	P	P	Accessory Building to Main Use		P	P	P	P	<u>P</u>	<u>P</u>
P	P	P	P	Carport		P	P	P	P		
				<u>Drive thru</u>		<u>S</u>	<u>S</u>	<u>P</u>	<u>P</u>		<u>P</u>
<u>S P</u>	<u>S P</u>	<u>S P</u>	<u>S P</u>	Home Occupation		<u>SP</u>	<u>SP</u>	<u>S</u>	<u>S</u>	S	
P	P	P	P	Field/Sales Office		P	P	P	P	P	P

(c) *Residential uses.*

RA	R-1	R-2	MH	Type of Use:	GP	C-1	C-B	C-2	I	H	PI
P	S	P		Bed and Breakfast		P	P			S	
		S		Bed and Breakfast with Event Facilities		S	S	S		S	
		P		Boarding/Rooming House		S					
		<u>S</u>	<u>S</u>	<u>Cabin or Cottage (Rental)</u>							
		<u>P</u>		<u>Condominiums/Townhouses</u>		<u>P</u>	<u>P</u>			<u>S</u>	
		<u>P</u>		<u>Continuing Care Facility</u>		<u>P</u>	<u>S</u>				<u>P</u>
P	P	P		Guest Home		S	S			S	
			P	Manufactured Home HUD Code							
			P	Manufactured Home Park							
			P	Manufactured Home Subdivision							
				<u>Mixed Use Residential Use in Buildings with Non-Residential Uses Permitted in the District</u>	P	P	P	S	S	P	P
				<u>Motel/Motor Hotel/Motor Lodge/Hotel</u>		<u>S</u>		<u>P</u>			
		P		Multi-family Residence/Dwelling		P	S				
		S	P	Recreational Vehicle/Motor Vehicle Park		S		S			
		<u>P</u>		<u>Townhouse/ Rowhouse</u>		<u>P</u>					

		P <u>S</u>		Elderly Care Facility Retirement Housing/Assisted Living		P	P <u>S</u>	<u>P</u>		<u>S</u>	P
P	P	P	P	Servant's, caretakers or Guard Residence		P	P	P	P	P <u>S</u>	
P	P	P		Single Family Dwelling Attached/ Townhouse/Rowhouse		P	P			P	
P	P	P		Single Family Dwelling Detached		P	P			P	
P	P	P	P	Single Family Modular Home		P	P			P	
		P		Duplex/Two Family		P	S				

(d) Educational, institutional and special uses.

RA	R-1	R-2	MH	Type of Use:	GP	C-1	C-B	C-2	I	H	PI
S	S	S		Adult Daycare Facility		P	P				P
P	P	P	P	Agricultural Related Uses (Farm, Ranch, Orchard, Livestock)***	<u>P</u>	P	P	P	P	<u>P</u>	P
S				Animal Shelter				P	P		P
				Archery Range, Indoor		P	P	P	P		
S				Archery Range, Outdoor		S	S	P	P		S
				Armed Services Recruiting Center	P	P	P	P	P		
<u>S</u>	<u>S</u>	<u>S</u>		Places of Assembly		S	S	S	S	S	P
S				Athletic Fields		S	S	P			P
				Barber/Beauty College (barber or cosmetology school or college)		P		P	P		P
S	S	S	S	Cemetery/ Mausoleum		S	P	P	P		P
S	S	S	S	Childcare Center		P	P	S	S		P
				Civic Center/ Community Center		S-P	P	P	P		P
				College/University		P	P	P	P		P
P	P	P	P	Community Building (associated with residential uses)Residential Amenity Building		S					
P	P	P	P	Community Home	P	P	P	P	P	P	P
				Community Center		P	P	P	S		P
S	S	S	S	Country Club, Private			P	P			P
				Dance Hall/Dancing Facility		P	S	P	P		
P				Day Camp		P		P			P
<u>S</u>	<u>S</u>	S	S	Daycare		P	P	P	S	P	P

S				Exhibition Area/Fairgrounds/ <u>Rodeo Arena & Grounds</u>		S	S	P	P		P
P	P	P	P	Family Home Adult Care		P					
P	P	P	P	Family Home Child Care		P					
S				Farmers Market		S	P	P		S	P
S	S	S		Fire Station or Public Building		P	P	P	P	P	P
				Fraternal Organization		S	S	P	P		P
S	<u>S</u>	<u>S</u>	<u>S</u>	Golf Course/Driving Range		S	S	P	P		P
P	P	P	P	Government/Institutional Building	<u>P</u>	P	P	P	P	P	P
<u>S-P</u>	<u>P</u>	<u>P</u>	<u>P</u>	Greenhouse/Plant Nursery(no retail sales on site)		<u>S-P</u>	<u>S-P</u>	P	P	<u>P</u>	<u>P</u>
S				Gun/Shooting Range (indoor)		S	S	P	P		
				Health Club/ Gymnasium		P	P	P	P		P
		<u>P</u>		<u>Hospice</u>		<u>P</u>	<u>P</u>				<u>P</u>
P	P	P	P	Hospital, <u>general or rehabilitation</u>		P	P	P	P		P
<u>P</u>	<u>P</u>	<u>P</u>	<u>P</u>	<u>Hospital, rehabilitation</u>		<u>P</u>	<u>P</u>	<u>P</u>	<u>P</u>		<u>P</u>
S				Kennel/ <u>Stable</u> /Animal Boarding/ <u>Housing</u>		S	S	P	P		
				Laboratory, Medical/Dental, Scientific or Research		S	S	P	P		P
		S		Library		P	P	P			P
				Museum/Art Gallery	S	P	P	P	S		P
				Nursery School/ Kindergarten		P	P	P	S		P
P	P	P	P	Park/Playground, Private		P	P	P	P	P	
	P	P	P	Park/Playground, Public		P	P	P	P	P	P
		<u>P</u>		<u>Respite Care Facility</u>		<u>P</u>	<u>P</u>			<u>P</u>	<u>P</u>
		<u>S</u>		<u>Rest Home/Nursing Home</u>		<u>S</u>		<u>P</u>			<u>P</u>
<u>S</u>				<u>Rodeo Arena and Grounds</u>			<u>S</u>	<u>P</u>	<u>P</u>		<u>P</u>
				School, Trade/ Commercial		S	S	P	P		P
S	S	S	S	School; Primary/Secondary		P	S	P	P		P
S	S	S	S	Stadium/Play Field, Public <u>Athletic Fields</u>		S	S	P	P		P
				Swimming Pool Commercial		P		P	P		P
P	P	P	P	Swimming Pool Private or HOA	P	P					
P	P	P	P	Swimming Pool Public		P		P	P	P	P

(e) *Transportation, utility and communications.*

RA	R-1	R-2	MH	Type of Use:	GP	C-1	C-B	C-2	I	H	PI
<u>S</u>				Airport/Landing Field				S	<u>P-S</u>		<u>P-S</u>

				Aircraft Support and Related Services				P	P		P
				Ambulance Service (private)		P	P	P	P		
				Communication Equipment (installation and/or repair)				P	P		
S				Compressor Stations, Related to Gas Well Drilling				S	S		S
				Electrical Generating Plant					P		P
S	S	S	S	Electrical Substation		S	S	P	P		P
S	S	S	S	Franchised Utility (Public or Private)		S	S	P	P		P
S				Gas Metering Station				P	P		P
S				Heliport or Helistop				P	S		P
				Landfill					S		
		P	P	Recycling Bins		P	P	P	P		P
				Recycling Facility (Sorting & Storage)					P		
S				Renewable Energy System, Commercial (ie. Solar or wind)				S	S		S
S				Service Yard of Government Agency		S	S	P	P		P
S	S	S	S	Sewage Pumping Station		S		P	P		P
S				Sewage Treatment Plant				S	P		P
S				Shops/ Office / Storage Area of Public/Private Utility		P	S	P	P		P
S	S	S	S	Solar Energy System	S	S	S	S	S	S	S
S	S	S	S	Telephone Exchange Station		S	S	P	P		P
P	P	P	P	Water Pumping Station/Well/Storage		P		P	P		P
S				Water Treatment Plant			S	S	P		P
S	S	S	S	Wind Energy System	P	S		P	P	P	P

(f) Automobile and related service uses.

RA	R-1	R-2	MH	Type of Use:	GP	C-1	C-B	C-2	I	H	PI
				Auto Defensive Driving Classes		P	P	P	P		
				Auto Driving School (including defensive driving)		P	P	P	P		
				Auto Glass Repair/Tinting		P		P	P		
				Auto Interior Shop/Upholstery		S		P	P		
				Auto Leasing/Rental		P	P	P	P		
				Auto Paint & Body Shop				P	P		P

				Auto Muffler Shop				P	P		
				Auto Parts Sales		P	S	P	P		
				Auto Repair/Service Station		S	S	P	P		P
				Auto/ <u>Motorcycle/ATV Sales, Service, Leasing, and Rental</u> (New and Used)		S	S	P	P		
				Auto Wrecking Yard/ Salvage Yard				S	P		
				Battery Charging Station		P	P	P	P		P
				Bus Barns or Lots				P	P		P
				Bus Passenger Stations		P	P	P	P		P
				Car Wash (self-service; automated)		S		P	P		P
				Car Wash (full-service detail shop)		S		P	P		
				Filling Station (fuel tanks must be underground)		S		P	P		P
				Heavy Machinery Sales & Service				S	P		
				Motorcycle/ATV Sales & Service		S		P	P		
				<u>Parking Lot, Standalone</u>		<u>P</u>	<u>P</u>	<u>P</u>	<u>P</u>		<u>P</u>
				Parking Lot /Parking Garage		S	S	P	P		P
				Quick Oil Change Facility		S	S	P	P		
				Tire Dealer				P	P		
				Trailer Sales/Rental				P	P		
				Truck and Bus Repair and Leasing				P	P		
				Truck and/or Equipment Storage Yard/Lot				S	P		P
				Truck Sales				S	P		
				Truck Stop with Fuel and Accessory Services				P	P		
				Truck/Motor Freight Terminal				S	P		
				Vehicle Storage Facility				P	P		

(g) Office, retail, commercial and service type uses.

RA	R-1	R-2	MH	Type of Use:	GP	C-1	C-B	C-2	I	H	PI
				Amusement, Commercial		S	P	P	P		
				Amusement, Outdoor/ Amphitheater		S		P	P		S
				Animal Grooming Shop		P	P	P			
				Answering and Message Services	P	P	P	P	P		
				Antique Shop		P	P	P	S		

			Appliance Sales, Service & Repair (No outdoor storage)		P	P	P	P		
	P		Arcade		P	P	P	P	P	P
			Arts & Crafts/Handcraft Store		P	P	P	P	P	
			Auction (Not to Include Auto/Truck/ Trailer)			S	P	P		
			Bakery & Confectionery, Retail Sales		P	P	P	P		
			Bank/Savings & Loan/Credit Union (without drive thru)		P	P	P	P	P	P
			Bank/Savings and Loan/Credit Union (with drive-thru)		S	S	P	P		P
			Beauty/Barber Shop	P	P	P	P	P		
			Bicycle Sales and/or Repair		P	P	P			
			Billiard or Pool Facility		P	P	P			
			Bingo Facility		P	P	P	P		P
S			Blacksmith or Wagon Shop				P	P		P
			Boat Sales & Storage				P	P		
			Book Store		P	P	P			
			Brewpub (microbrewery)		P	P	P	P		
			Building Materials		S	S	P	P		
			Carpet Cleaning Establishment		P	P	P	P		
			Caterer		P	P	P	P	P	
			Check Cashing Service		P	P	P	P		
			Clinic Dental	P	P	P	P	P		
			Clinic Emergency/Urgent Care	S	S	S	P	P		
			Clinic Medical or Dental	P	P	P	P	P		
			Coffee Shop (without drive thru)		P	P	P	P	P	
			Coffee Shop (with drive thru)		S	S	P	P	P	
			Computer and Electronic Sales		P	P	P	P	P	
			Computer Repair		P	P	P	P	P	
			Confectionery Store (retail)		P	P	P	P	P	
			Convenience Store		S	S	P	P	S	
			Convenience Store With Gas Sales		S	S	P	P		
			Convenience Store with Drive Thru		S	S	P	P		
			Credit Agency		P	P	P	P		
			Dry Cleaning/Laundry, Pick-Up & Drop-Off Only		P	P	P	P		
			Dry Cleaning/Laundry, with drive- thru		S	S	P	P		
			Drug Store/Pharmacy		P	P	P	P		
			Drug Store/Pharmacy with Drive Thru		S	S	P	P		
			Exterminator Service		P	P	P	P		
S			Feed & Farm Supply		P	P	P	P		

S				Flea Market		S	S	P	P		
				Florist		P	P	P	P		
				Food/Grocery Store		P	P	P	S		
				Furniture Sales (Indoor)		P	P	P	P	P	
S				Game Processing				P	P		
				Game Room				P	P		
				Garden Center, Retail Sales <u>Indoor</u>		P	P	P	P		
				Garden Center/Plant Nursery, Retail Sales with outdoor storage		S	S	P	P		
				General Merchandise Store		P	P	P	P		
				Gymnastic/Dance Studio		P	P	P	P		
				Handcraft Shop		P	P	P	P	P	
				Health Club (physical fitness; indoors only)		P	P	P	P		P
P	P	P	P	Ice Cream Truck	P	P	P	P	P	P	P
				Kiosk Exterior (providing a retail service)		P	P	P	P		
				Kiosk Interior		P	P	P	P	P	
S				Live Animal Slaughter House					P S		
		S		Laundromat/Washateria (self-service)		P	P	P	P		
				Laundromat/Washateria Incidental to Multi-family Housing							
				Limousine/Taxi Service		S	S	P	P		
				Locksmith		P	P	P	P		
				Lumbyard/Building Materials (outside storage yard)		S		P	P		
S				Lumbyard/Building Materials (no outside yard)		P	P	P	P		
				Mail Services/Copy Center		P	P	P	P		
				Maintenance/Janitorial Service		S	S	P	P		P
				Maintenance/Janitorial Service (retail sales only)		P	P	P	P		
				Manufactured Home Sales				P	P		
				Martial Arts School		P	P	P	P		
				Medical Supplies/Sales/Service		P	P	P	P	P	
				Metal Dealer, crafted precious		P	P	P	P	P	
				Massage Establishment	P	P	P	P	P	P	
				Metal Dealer - Crafted Precious		P	P	P	P	P	
P				Mobile Food Vendor	P	P	P	P	P	P	P
				Monument, Gravestone, Granite or Marble Retail Sales (not fabrication)		P <u>S</u>		P	P		
				Mortuary/Funeral Home		S	P	P	P		
				Motel/Motor Hotel/ Motor Lodge/Hotel		<u>S</u>		<u>P</u>			

			Newspaper Printing			S	P	P		
			Offices, Brokerage Services	P	P	P	P	P	P	
			Offices, Computer Programming and Data Processing		P	P	P	P	P	
			Offices, Consulting	P	P	P	P	P	P	
			Offices, Engineering, Architecture, Surveying or Similar	P	P	P	P	P	P	
			Offices, Health Services	P	P	P	P	P	P	P
			Offices, Insurance Agency	P	P	P	P	P	P	P
			Offices, Private Law Offices	P	P	P	P	P	P	P
			Offices, Legal Services Including Court Reporting		P	P	P	P	P	P
			Offices, Medical & Professional	P	P	P	P	P	P	P
			Offices, Real Estate	P	P	P	P	P	P	P
			Offices, Security/Commodity Brokers, Dealers, Exchanges, and Financial Services	P	P	P	P	P	P	
			Outside Storage (primary use)					P		
			Pet Shop/Supplies		P	P	P	P		
			Photographic Printing/Duplicating/Copying Shop or Print Shop		P	P	P	P	P	P
			Plant Nursery (retail sales/outdoor storage)			P	P	P	P	
			Professional Office(s)	P	P	P	P	P	P	
			Pawnshop					P		
			Personal Services	P	P	P	P	P	P	
			Pet Shop			P	P	P		
			Pharmacy			P	P	P		
			Plumbing/Heating/Refrigeration/Air Conditioning Sales, Service & Supply (No outdoor storage)		P	P	P	P		
			Plumbing/Heating/Refrigeration/Air Conditioning Sales, Service & Supply (outdoor storage)				P	P		
			Portable Building Sales		S	S	P	P		
			Print Shop		P	P	P	P		P
			Refreshment Stand		P	P	P	P		P
			Rental Store (no outside storage)		P	P	P	P		
			Restaurant/Cafeteria, Dine-In Service Only		P	P	P	P	P	P
			Restaurant/Cafeteria, with Drive-In or Drive Through Service		S	P S	P	P		
			Retail Shops/Stores		P	P	P	P	P	

				Retail Shops/Stores (drive-through service)		S	S	P	S			
				Sand and Gravel Sales (storage and sales)					P			
				Secondhand Store, Furniture/Clothing		P	P	P	P			
				Security Monitoring Company (no outside storage or installation)		P	P	P	P			
				Security Systems Installation and Monitoring (no outside storage)		P	P	P	P			
				Sexually Oriented Businesses					S			
				Shoe Repair Shop		P	P	P	P	P		
				Shopping Center		P	P	P	P			
				Smoke/ Vape/ CBD Shop		S	S	S	SP			
				Smoke Lounge		S	S	S	SP			
				Studio, Artist/ Photographer	P	P	P	P	P	P		
				Studio Musician	S	P	P	P	P	S		
				Studio, Radio/ Television		SP	P-S	P	P			P
				Tailor Shop (see home occupation)	P	P	P	P	P	P		
S				Taxidermist			S	P	P			
				Tattoo or Body Piercing Studio	P	P	P	P	P	P		
				Telemarketing Agency		P	P	P	P			
				Theater Motion Picture (indoor)		P	P	P	S			
S				Theater Motion Picture (drive-in)				P	P			
				Tool Rental Facility		S	P	P	P			
				Travel Agency	P	P	P	P	P	P		
				Veterinarian Clinic, No Outside Pens		P	P	P	P			
				Veterinarian Clinic, Large Animal with Outside Pens		S	S	P	P			
				Movie and Music Rental/Sales		P	P	P	P	P		
		P		Movie Kiosk	P	P	P	P	P	P		

(h) Manufacturing, storage and warehousing uses.

RA	R-1	R-2	MH	Type of Use:	GP	C-1	C-B	C-2	I	H	PI
				Bakery Commercial Production				P	P		
				Biomedical Facility				P	P		P
				Blooming or Rolling Mills					P		
				Book Binding Facility				P	P		
				Bottling or distribution plant (milk)					P		
				Bottling plant					P		

				Breweries/Distilleries and Manufacture of Alcohol and Alcoholic Beverages		<u>S</u>	S	P	P		
				Carpentry, cabinet, or pattern shop				P	P		
				Chemical Laboratories (e.g. ammonia, bleaching powder)					P		
				Chemical Laboratories (not producing noxious fumes or odors)				<u>P</u> <u>S</u>	P		
				Cold Storage Plant				P	P		
				Concrete or asphalt Mixing Plants (permanent)					P		
				Concrete or asphalt Mixing Plants (temporary)					P		
				Contractor's Office/Sales With Outside Storage Including Vehicles				P	P		
P	P	P	P	Contractor's Temporary On-site Construction Office		P	P	P	P		P
				Dry-Cleaning Plant/Facility				P	P		
				Electronic Assembly/High Tech Manufacturing				P	P		
				Electroplating Works				S	P		
				Enameling Works					P		
				Flour Mills, Feed Mills, and Grain Processing					P		
				Freight Terminal (when any storage of freight is wholly outside an enclosed building)					P		
				Freight Terminal (all storage of freight in an enclosed building)				P	P		
				Frozen Food Storage for Individual or Family Use				P	P		
				Furniture Manufacture				P	P		
				Galvanizing Works				S	P		
<u>S</u>				Game Processing				P	P		
				Grain Elevator					P		
<u>S</u>				Greenhouse-Commercial (No Retail Sales)				P	P		
				Heavy Industrial/Manufacturing					P		
				Industrial Laundry / <u>Dry Cleaning Facility</u>				P	P		
				<u>Industrial Park</u>					P		

				Junkyard/Salvage Yard						P		
				Light Industrial/Manufacturing				S		P		
				Machine Shop				P		P		
				Meat or Fish Packing/Storage Plant						P		
				Metal Fabrication Shop				P		P		
S				Mill; Grain/Flour/ Food Products		S	S	P		P		
				Mines & Quarries						P		
				Monument, gravestone, or marble works (manufacture)				P		P		
				Moving or Storage Company				P		P		
				Newspaper Printing				S		P	P	
				Pipe Sales & Supply				P		P	P	
				Plastic Products Molding/Reshaping				P		P		
				Poultry Processing or Dressing for Commercial Purposes						P		
				Scrap Metal Sales & Storage				S	S	P		
				Self Storage; Mini-warehouse (no outside storage of boats, RVs, and trailers)		S		P		P		
				Self Storage; Mini-warehouse (with outside boat, RV and trailer storage)				P		P		
				Steel Fabrication				S	S	P		
				Storage/Wholesale Warehouse				S	S	P		
				Tire Recapping or Retreading						P		
				Transfer Station (refuse/pick-up)						P		P
				Welding Shop				P		P		P
				Wholesale Offices and Sample Rooms				P		P		
				Wrecking/Junk/Salvage Yard						P		

(Ord. No. 120910-01, § 1(ch. 4, § 2), 12-9-2010; Ord. No. 013014-01, § 1(Exh. A), 1-30-2014; Ord. No. 091219-04, § 1(Exh. A), 9-12-2019)

{Amendments to Sec.38-304. Additional use regulations}

Sec. 38-304. - Additional use regulations.

(4) ~~Elderly care facility, Retirement housing, assisted living,~~ adult day care. The following subsidiary uses may be permitted to provide on-site goods and services for residents and their guests, but are not intended for use by the general public:

- a. Cafeteria and/or dining room;
- b. Library;
- c. Game room;
- d. Swimming pool and/or Jacuzzi;
- e. Exercise room;
- f. Arts and crafts facilities;
- g. Greenhouse;
- h. Housekeeping service;
- i. Transportation service;
- j. Snack bar with a maximum of 350 square feet per 100 dwelling units;
- k. Beauty/barber shop with a maximum of 450 square feet per 100 dwelling units or a minimum of 250 square feet per 100 dwelling units;
- l. Convenience retail shop with minimum of 350 square feet per 100 dwelling units to provide for sale of food items, nonprescription drugs, small household items, and gifts.

(5) ~~Servant's/caretaker's/guard's residence.~~ The living area of a ~~servant's, caretaker's, or guard's~~ residence shall not exceed 1,000 square feet.

(6) Guest Home. The living area of a Guest home shall not exceed 1,000 square feet.

~~(6)~~ Swimming pool (Private or HOA): Swimming pools shall be located within the required side or rear yards provided, however, that a pool shall not be located closer than eight feet to any property line or utility easement.

~~(7)~~ Community home. shall provide the following services to persons with disabilities who reside in the home include:

- a. Food and shelter;
- b. Personal guidance;
- c. Care;
- d. Habilitation services; and
- e. Supervision.

A community home must have not more than six persons with disabilities or more than two supervisors that reside in the home at the same time; must meet all applicable state licensing requirements; and must not be established within one-half mile of an existing community home.

Except as otherwise provided by this ordinance, the residents of a community home may not keep for the use of the residents of the home, either on the premises of the home or on a public right-of-way adjacent to the home, motor vehicles in numbers that exceed the number of bedrooms in the home. A "community home" may include any facility regardless of whether it is referred to by a different name if it meets the terms of this definition, (i.e.

"assisted living facilities, group homes, retirement homes, etc. and may include the provision of respite care if all other provisions of this definition apply) Any such facility that meets the requirements of this definition shall be governed by the regulations contained in this ordinance that apply to a community home.

{Amendments to Sec.38-405. Home occupation regulations}

Sec. 38-405. – Home occupation regulations.

(b)Required conditions.

- (1) The area set aside for home occupations shall not exceed 20 percent of the total floor area of such residence. A specific use permit may be granted to allow for home occupations to exceed 20 percent of the total floor area of the residence.
- (2) A home occupation shall not have any ~~No~~ interior or exterior business signs ~~shall be permitted~~ nor any display that will indicate from the exterior that the building is being utilized in part for any purpose other than that of a dwell, except a nameplate not more than 1 square foot in area is permitted on the exterior of the building.
- (3) No mechanical equipment is used except of a type that is similar in character to that normally used for purely domestic or household mechanical equipment as for hobby purposes in conjunction with the home occupation.
- (4) Retail sales shall be prohibited on the premises except for the retail sales of products and goods produced and fabricated on the premises as a result of the home occupation.
- (5) Only members of the immediate family permanently residing on the premises shall be employed in the home occupation. A specific use permit may be granted to allow for persons other than the immediate family permanently residing on the premises to be employed in the home occupation.
- (6) In no case shall a home occupation be open to the public at times earlier than 8:00 a.m. and no later than 10:00 p.m.
- (7) No more than one home occupation shall be permitted within any single dwelling unit.
- (8) A home occupation shall be carried on wholly within the principal building. No home occupation or any storage of goods, materials, or products connected with a home occupation shall be allowed in accessory buildings or garages, attached or detached, excluding paints and chemicals that may be used in the home occupation. A specific use permit may be granted to allow for the home occupation to operate outside of the principal building, including operating out of an accessory building.
- (9) There shall be no exterior indication of the home occupation or variation from the residential character of the principal building.

(10) There shall be no exterior storage of materials to be used in conjunction with a home occupation. A specific use permit may be granted to allow for the exterior storage of materials used in conjunction with the home occupation.

(11) A home occupation shall produce no offensive or obnoxious noise, vibration, smoke, electrical interferences, dust, odors, heat or other obnoxious conditions detectable beyond the property limits or beyond the walls of the dwelling unit. The judgment of the city's code enforcement officer pertaining to a violation under this section shall be considered decisive and final unless formally appealed to the board of adjustment within 30 days of the code enforcement officer's written determination.

(12) A home occupation shall not create any increased traffic generation.

(13) All home occupations may be subject to periodic inspections.

(14) A home occupation ~~shall not have any signage other than a nameplate not more than one square foot in area nor any display that will indicate from the exterior that the building is being utilized in part for any purpose other than that of a dwelling, shall not have any commodity sold on the premises, shall not employ any person other than a member of the immediate family residing on the premises nor shall there be any mechanical equipment used except of a type that is similar in character to that normally used for purely domestic or household purposes.~~

(15) A home occupation shall not use mechanical equipment except of a type that is similar in character to that normally used for purely domestic or household purposes.

{Amendments to Sec.38-413. Kiosk}

Sec. 38-413. – Kiosk.

(a) *Exterior kiosk.*

(5) A kiosk can only offer drive-thru service if it's allowed according to the permitted use chart (Section 38-302(b)) for the zoning district where the kiosk is located, or if the kiosk has obtained a Special Use Permit in a district where such a permit is required. If the kiosk has a drive-thru service, the drive-thru must comply with the stacking requirements for drive-thru uses subsections 38-402(h)(5).