NEAL & HARWELL, PLC

LAW OFFICES
150 FOURTH AVENUE, NORTH
SUITE 2000
NASHVILLE, TENNESSEE 37219-2498

TELEPHONE
(615) 244-1713

FACSIMILE
(615) 726-0573

WWW.NEALHARWELL.COM

December 16, 2014

Sharla Dillon, Dockets Manager
Tennessee Regulatory Authority
Andrew Jackson State Office Building
Fourth Floor
500 Deaderick Street
Nashville, TN 37242

VIA E-MAIL AND HAND DELIVERY
sharla.Dillon@tn.gov

RE: Atmos Energy General Rate Case and Petition to Adopt Annual Review Mechanism and ARM Tariff, TRA Docket No. 14-00146

Dear Ms. Dillon:

Enclosed for filing are an original and four copies of Atmos Energy Corporation's responses to the Authority's Filing Guidelines for Rate Cases, commonly referred to as the "MFR's." I have included one copy of the Confidential portions, which are in a separate, marked envelope.

I also enclose a box containing one complete copy of everything, including the confidential materials, for TRA Staff. The TRA Staff box includes a set of CDs containing native versions of the electronic files (i.e. Word and Excel versions).

Tomorrow I will send you a CD containing PDF versions of the filing for upload to the Authority's docket website.

Thank you for your assistance. Please give me a call if you have any questions.

Best regards.

Sincerely,

A. Scott Ross

ASR:prd

Enclosure

cc: Wayne Irvin (by hand delivery – 2 copies, including CDs)

REQUEST:

If material to the LDC's cost or level of service in Tennessee, please provide a comprehensive discussion of all abnormal conditions or changes in condition that (a) occurred during the last three years or (b) are reasonably anticipated to occur up to the anticipated hearing date in this case. Explain how these changes will affect the LDC's Tennessee operations going forward. The discussion should include, but not be limited to the following:

a. Management changes

b. Operational changes

c. Administrative changes

d. Recent or pending mergers, consolidations, or acquisitions

e. Major changes in sales or transportation volumes

f. Pending negotiations for possible changes in sales or transportation volumes to any current or prospective commercial or industrial customer.

g. Changes in pipeline allocations.

h. Labor contracts and/or Union problems

i. Expenses

RESPONSE:

a) Not applicable.

b) Not applicable.

c) Not applicable.

d) Not applicable.

e) Please see the Company's Confidential response to MFR No. 1-17 for anticipated changes in sales and transportation volumes.

f) Please see the Company's Confidential response to MFR No. 1-27.

g) Not applicable.

h) Not applicable.

i) There have been and are expected to be numerous changes in expense levels for Atmos Energy's operations in Tennessee over the last three years and anticipated through the hearing date in this case. The details of various expenses are covered thoroughly in the subsequent minimum filing requirements and the pre-filed Direct Testimony of Greg Waller. None of these, however, would qualify as arising from material abnormal conditions.

Respondents: Greg Waller and Patricia Childers

REQUEST:

State the effect that each of the applicable changes discussed in Item 14 has had or will have on the LDC's, its Parent's, Multi-State Utility's, or Affiliated Utility Service Company's, revenues, expenses, rate base, and capital structure, including the LDC's, its Parent's, Multi-State Utility's, or Affiliated Utility Service Company's, method of allocating each change among its regulated, unregulated, and jurisdictional operations.

RESPONSE:

The changes discussed in the Company's response to MFR No. 1-01 have had the following effects on:

Revenues - Please see the Company's Confidential responses to MFR Nos. 1-17 and 1-27 for anticipated changes in sales and transportation revenues.

Expenses - Please see the Company's response to MFR No. 1-01 subpart (i).

Rate Base - The rate base in Tennessee has not been materially affected due to changes discussed in the Company's response to MFR No. 1-01.

Capital Structure - The capital structure in Tennessee has not been materially affected due to changes discussed in the Company's response to MFR No. 1-01.

Method of allocation - The Company's method of allocation has not been materially affected due to changes discussed in the Company's response to MFR No. 1-01.

Respondents: Greg Waller and Patricia Childers

REQUEST:

Provide a current organizational chart for the LDC and, if applicable, its Parent, Multi-State Utility, or Affiliated Utility Service Company, showing for each officer (or any other key personnel) of the LDC, its Parent, Multi-state Utility, or Affiliated Utility Service Company: (a) the department(s) they head, and (b) to whom they report, from department or office level up. Only officers and key personnel, all or some portion of whose compensation is sought to be recovered from Tennessee ratepayers, must be included in the chart.

RESPONSE:

Please see Attachment 1.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_1-03_Att1 - Organization Chart.pdf, 1 Page.

Respondent: Greg Waller

Atmos Energy Corporation
Organization Chart as of October 31, 2014

Title - President & CEO
Location - Dallas, TX
Division - Shared Services

Title - Sr VP Utility Operations
Location - Dallas, TX
Division - Shared Services

Title - President
Location - Franklin, TN
Division - Kentucky/Mid-States Division

Title - VP Rates & Reg Affairs
Location - Franklin, TN
Division - Kentucky/Mid-States Division

Title - VP Finance
Location - Franklin, TN
Division - Kentucky/Mid-States Division

Title - VP Operations
Location - Owensboro, KY
Division - Kentucky/Mid-States Division

Title - VP Operations
Location - Johnson City, TN
Division - Kentucky/Mid-States Division

Title - VP Rates & Reg Affairs
Location - Owensboro, KY
Division - Kentucky/Mid-States Division

Title - VP Governmental Affairs
Location - Owensboro, KY
Division - Kentucky/Mid-States Division

Title - VP Marketing
Location - Bowling Green, KY
Division - Kentucky/Mid-States Division

Title - VP Technical Services
Location - Franklin, TN
Division - Kentucky/Mid-States Division

Title - VP Human Resources
Location - Franklin, TN
Division - Kentucky/Mid-States Division

Title - VP Customer Service
Location - Dallas, TX
Division - Shared Services

Title - VP Pipeline Safety
Location - Plano, TX
Division - Shared Services

Title - Sr VP Human Resources
Location - Dallas, TX
Division - Shared Services

Title - Sr VP General Counsel & Corporate Secretary
Location - Dallas, TX
Division - Shared Services

Title - VP Governmental & Pub Affairs
Location - Dallas, TX
Division - Shared Services

Title - Sr VP & CFO
Location - Dallas, TX
Division - Shared Services

Title - VP & Controller
Location - Dallas, TX
Division - Shared Services

Title - VP Finance
Location - Houston, TX
Division - Atmos Energy Holdings Inc.

Title - VP Strategic Planning
Location - Dallas, TX
Division - Shared Services

Title - VP & Treasurer
Location - Dallas, TX
Division - Shared Services

Title - VP Tax
Location - Dallas, TX
Division - Shared Services

Title - VP & Chief Info Officer
Location - Dallas, TX
Division - Shared Services

Title - VP Investor Relations
Location - Dallas, TX
Division - Shared Services

REQUEST:

Provide six (6) copies of the Annual Stockholder Reports, the 10K reports, and 10 Q reports for the LDC, its Parent, Multi-state Utility, or Affiliated Utility Service Company, for the last three (3) years.

RESPONSE:

Please see Attachment 1 for the Annual Reports, Attachment 2 for the Form 10-K Reports and Attachment 3 for the Form 10-Q Reports available for the last three years. The requested information is also available electronically on the Company's website at http://www.investquest.com/iq/a/ato/fin/annual/index.htm. The Company is providing one hard copy of the reports in three separate volumes and five electronic copies on CD.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_1-04_Att1 - Annual Reports.pdf, 104 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, Staff_1-04_Att2 - Form 10-Ks.pdf, 374 Pages.

ATTACHMENT 3 - Atmos Energy Corporation, Staff_1-04_Att3 - Form 10-Qs.pdf, 557 Pages.

Respondent: Jason Schneider

Docket No. 14-00146
Atmos Energy Corporation, Tennessee Division
MFR Set No. 1
Question No. 1-05

REQUEST:

If the LDC is a separate entity, provide a current chart of accounts for the LDC and, if applicable, its Affiliated Utility Service Company. If the LDC is an operating division, also provide a current chart of accounts for the Multi-state Utility.

RESPONSE:

Please see Attachment 1 for the chart of accounts.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_1-05_Att1 - Chart of Accounts.xls, 98 Pages.

Respondent: Jason Schneider

Company	Description
010	Atmos Regulated Shared Services
020	Atmos Energy-Louisiana
030	Atmos Energy-West Texas
040	Use 050 Atmos Energy-Kentucky
050	Atmos Energy-KY/Mid-States
060	Atmos Energy-Colorado-Kansas
070	Atmos Energy-Mississippi
080	Atmos Energy-Mid-Tex
180	Atmos Pipeline - Texas
210	Blueflame Insurance Services, LTD
212	Atmos Energy Marketing LLC (Formerly Wo
221	Atmos Power Systems Inc (Formerly Atmos
231	Atmos Pipeline & Storage LLC (Formerly
232	UCG Storage
233	WKG Storage
234	Trans Louisiana Gas Storage
236	Atmos Gathering Company, LLC
237	Phoenix Gas Gathering Company
240	Fort Necessity Gas Storage, LLC
301	Atmos Energy Services LLC (Previous Inc
302	Egasco
303	Trans Louisiana Gas Pipeline (Formerly
304	United Cities Energy Services
306	Atmos Exploration & Production (Formerl
308	Enermart Energy Services (Formerly Ener
312	Atmos Energy Holdings Inc (Formerly At
981	Atmos Energy Corporation Cons (Elim)
982	Atmos Energy Company (BU Elim)
983	Atmos Storage (Elim)
984	Atmos Energy Services (Elim)
985	Enertrust Inc. (Elim)
987	Other Operating Companies (Elim)
988	Energas Enermart (Elim)
989	Blueflame Insurance (Elim)
990	Mid-Tex Eliminations
991	Straight Creek Elimination Company

Cost Center	Description
0000	Default
1101	SS Dallas Chief Financial Officer
1105	SS Dallas Audit
1106	SS Dallas Treasurer
1107	SS Dallas Treasury
1108	SS Dallas Risk Management
1110	SS Dallas Procurement
1111	SS Dallas Purchasing
1112	SS Dallas Mail & Supply
1114	SS Dallas Vice Pres & Controller
1116	SS Dallas Taxation
1117	SS Dallas Acctg Services
1118	SS Dallas Supply Chain
1119	SS Dallas General Accounting
1120	SS Dallas Accounts Payable
1121	SS Dallas Plant Accounting
1123	SS Dallas Gas Accounting
1125	SS Dallas Financial Reporting
1126	SS Dallas Payroll
1128	SS Dallas Property & Sales Tax
1129	SS Dallas Income Tax
1130	SS Dallas Business Planning and Analysis
1131	SS Dallas Media Relations
1132	SS Dallas Investor Relations
1133	SS Dallas Communications
1134	SS Dallas IT
1135	SS Dal-IT E&O, Corporate Systems
1137	SS Dallas IT Engineering & Operations
1141	SS Dallas Gas Purchase Accounting
1144	SS Dallas Rate Administration
1145	SS Dallas Revenue Accounting
1150	SS Dallas Strategic Planning
1153	SS Dallas Distribution Acctg
1154	SS Dallas Rates & Regulatory
1155	SS Dallas Texas Gas Pipeline Accounting
1156	SS Dal-IT Customer Services Systems
1158	SS CCC IT Support
1159	SS Dallas Director Technical Training
1161	SS Dallas Benefits and Payroll Accountin
1164	SS Dallas IT Security
1165	SS Dal-IT Security
1167	SS Dallas IT Enterprise Architecture
1171	SS Dallas Regulatory Accounting
1201	SS Dallas President & CEO
1205	SS Dallas SVP Utility Operations
1209	SS Dallas Safety & Compliance
1212	SS CSC-Customer Contact Management
1213	SS Dallas Quality Assurance
1214	SS Dallas Workforce Management
1215	SS Dispatch Operations
1224	SS Dallas CSO Human Resources
1225	SS Dallas Regulated Operations
1226	SS Dallas Customer Service
1227	SS Dallas Business Processes and Change
1228	SS Dallas Customer Revenue Management
1229	SS Dallas Pipeline Safety
1401	SS Dallas Employment & Employee Relation
1402	SS Dallas Executive Compensation
1403	SS Dallas Human Resources - Vice Pres
1405	SS Dallas Compensation & Benefits
1407	SS Dallas Facilities
1408	SS Dallas Employee Development
1414	SS Tech Training Delivery
1415	SS Tech Training Prog & Curriculum
1420	SS Dallas EAPC
1463	SS HR Benefit Variance
1501	SS Corporate Legal
1502	SS Corporate Secretary
1503	SS Corporate Governmental Affairs
1504	SS Corporate Records Management
1505	SS Corporate Gas Contract Administration
1507	SS Corporate Texas Lobbying
1508	SS Corporate Energy Assistance
1801	SS Franklin Nominations and Scheduling
1804	Use 9609 SS Franklin Gas Control
1821	SS Gas Supply Executive
1822	SS Dallas-Regional Gas Supply
1823	SS Dallas Gas Contract Admin
1825	SS Franklin-Gas Control & Storage
1826	SS New Orleans Gas Supply & Services
1827	SS Regional Supply Planning
1828	SS Jackson-West Region Gas Supply & Serv
1829	SS Franklin-East Region Gas Supply & Ser
1831	SS Dallas Gas Supply
1832	SS Dallas-Supply Planning
1833	SS Dallas-Corporate Gas Supply Risk Mgmt
1835	SS Franklin Gas Control
1836	SS TBS-System Support
1837	SS TBS-Application Support
1838	SS TBS-Technical Support
1839	SS TBS-Transportation & Scheduling
1901	SS Dallas Employee Relocation Exp
1903	SS Controller - Miscellaneous

Cost Center	Description
1904	SS Dallas Performance Plan
1905	SS Outside Director Retirement Cost
1908	SS Dallas SEBP
1909	SS Dallas I/C Billing & Other
1910	SS Corporate Overhead Capitalized
1913	SS Dallas Fleet and Corporate Sourcing
1915	SS Dallas Insurance
1953	SS Dallas Enterprise Team Meeting
1954	SS Dallas Culture Council
2001	West Texas Div Lubbock Administration
2002	West Texas Div Lubbock Information Servi
2003	West Texas Div Lubbock Human Resources
2004	West Texas Div Lubbock Regulatory Affair
2005	West Texas Div Lubbock Technical Service
2006	West Texas Div Lubbock Engineering Servi
2007	West Texas Div Lubbock Finance
2008	West Texas Div Lubbock Marketing
2009	West Texas Div Lubbock Measurement Cente
2010	West Texas Div Lubbock Revenue Managemen
2011	West Texas Div Facilities Replacement
2012	West Texas Div Asset Integrity & Complia
2013	West Texas Div Lubbock Maps & Records
2014	West Texas Div Lubbock Supply Chain
2018	West Texas Div Safety :Tech Services
2021	West Texas Div Relocation Expense
2025	West Texas Div Public Affairs
2032	West Texas Div Lubbock Central Region Bu
2034	West Texas Div Lubbock C&M/Service
2035	West Texas Div Littlefield C&M/Service
2036	West Texas Div Plainview C&M/Service
2037	West Texas Div Lubbock Ag and Industrial
2038	West Texas Div Triangle Operations
2044	West Texas Div Pipeline Integrity Manage
2063	West Texas Div HR Benefit Variance
2131	West Texas Div Amarillo Northern Region
2132	West Texas Div Amarillo Northern Region
2134	West Texas Div Amarillo C&M/Service
2135	West Texas Div Pampa C&M/Service
2136	West Texas Div Hereford C&M/Service
2231	West Texas Div Midland Southern Region A
2232	West Texas Div Midland Southern Region B
2233	West Texas Div Midland So Region Pub Aff
2234	West Texas Div Permian Basin C&M/Service
2236	West Texas Div Big Spring C&M/Service
2237	West Texas Div Seminole/Brownfield C&M/S
2401	LA Div Administration
2402	LA Div Information Technology
2403	LA Div Human Resources
2404	LA Div Rates & Regulatory Affairs
2405	LA Div Tech Services
2406	LA Div Engineering Services
2407	LA Div Finance
2408	LA Div Marketing
2409	LA Div Measurement
2412	LA Div Corrosion Control
2415	LA Div Compliance
2418	LA Div Safety :Tech Services
2421	LA Div Relocation Expense
2425	LA Div - SIIP
2431	LA-Finance-Accounting
2432	LA-Finance-Billing
2433	LA Div Public Affairs
2435	LA Div Pineville Service/C&M
2444	LA Div Pipeline Integrity Management
2450	LA Div Lafayette Operations
2451	LA Div Lafayette C&M
2453	LA Div Lafayette Service
2454	LA Div Natchitoches C&M/Compliance
2455	LA Div Natchitoches Service
2463	LA Div HR Benefit Variance
2467	LA Div Drafting
2470	LA Div Metro East Operations
2472	LA Div St Tammany C&M
2473	LA Div St Tammany Services
2474	LA Div Tangipahoa Services/C&M
2475	LA Div Ascension Service/C&M
2476	LA DIV EAC
2515	LA Div Monroe Compliance
2516	LA Div Western Region Administration
2532	LA Div Western Sales
2535	LA Div Monroe Operations
2536	LA Div Monroe C&M
2538	LA Div Delhi/Bastrop Service/C&M
2539	LA Div Monroe Service
2541	LA-Metairie-E Reg Public Affairs
2542	LA-Monroe-W Reg Public Affairs
2543	LA-Lafayette Public Affairs
2601	KMD-Owensboro Administration(Use 3301)
2602	KMD-Owensboro Information Services
2603	Use 3303 Mid St Div Owensboro Human Reso
2604	KMD-Owensboro Rates & Regulatory Affairs
2606	Use 3315-KMD-Owensboro Engineering
2609	KMD-Owensboro Storage & Transmission

Cost Center	Description
2612	KMD Owensboro Compliance
2618	KMD-Owensboro Safety :Tech Services
2631	KMD-Owensboro-N Reg Admin
2634	KMD-Madisonville C&M/Service
2635	KMD-Princeton C&M/Service
2636	KMD-Owensboro C&M/Service
2637	KMD-Paducah C&M/Service
2638	KMD-Mayfield C&M/Service
2650	KMD-Madisonville Operations
2651	KMD-Owensboro Operations
2653	KMD-Pipe Replacement Program Adm
2703	KMD-Owensboro Governmental Affairs
2731	KMD-Bowling Green East Region Administra
2732	KMD-Bowling Green East Region Marketing
2734	KMD-Bowling Green C&M/Service
2735	KMD-Glasgow C&M/Service
2736	KMD-Hopkinsville C&M/Service
2737	KMD-Danville C&M/Service
2738	KMD-Campbellsville C&M/Service
2739	KMD-Shelbyville C&M/Service
2750	KMD-Bowling Green Operations
3001	CO/KS Div Denver Administration
3002	CO/KS Div Denver Information Technology
3003	CO/KS Div Denver Human Resources
3004	CO/KS Div Regulatory Affairs
3005	CO/KS Div Denver Tech Services
3006	CO/KS Div Denver Engineering & Design
3007	CO/KS Div Denver Finance
3008	CO/KS Div Denver Marketing
3009	CO/KS Div Storage
3012	CO/KS Div Denver Engineering & Complianc
3017	CO/KS Div Denver Employee Development
3018	CO/KS Div Safety :Tech Services
3019	CO/KS Div Denver Measurement Center
3021	CO/KS Div Relocation Expense
3031	CO/KS Div Colorado Region Administration
3032	CO/KS Div Colorado Region Marketing
3033	CO/KS Div Colorado Region Public Affairs
3034	CO/KS Div Greeley C&M
3035	CO/KS Div Yampa Valley C&M/Svc
3036	CO/KS Div Craig C&M/Service
3037	CO/KS Div Canon City C&M/Service
3038	CO/KS Div Salida/Gunnison C&M/Svc
3039	CO/KS Div Gunnison C&M/Service
3040	CO/KS Div Lamar C&M/Service
3041	CO/KS Div SW Colorado C&M/Svc
3042	CO/KS Div Cortez C&M/Service
3050	CO/KS Div Operations
3051	CO/KS Div Canon City Operations
3063	CO/KS Div HR Benefit Variance
3131	CO/KS Div Bonner Springs Kansas Region A
3132	CO/KS Div Bonner Springs Kansas Region M
3134	Use 3143 CO/KS Div Bonner Springs C&M/Se
3136	CO/KS Div Herington C&M/Service
3139	CO/KS Div Ulysses C&M/Service
3141	CO/KS Div Olathe Operations
3143	CO/KS Div Olathe C&M
3144	CO/KS Div Independence Operations
3145	CO/KS Div Independence C&M
3146	CO/KS Div Yates Center C&M
3301	KMD-Franklin Administration
3302	KMD-Franklin Information Services
3303	KMD-Franklin Human Resources
3304	KMD-Franklin Rates & Regulatory Affairs
3305	KMD-Franklin Tech Services Administratio
3306	KMD-Franklin Project Engineering & Maps/
3307	KMD-Franklin Finance
3308	KMD-Franklin Marketing
3314	KMD-Franklin Environmental Services
3315	KMD-Franklin Measurement & Corrosion Con
3320	KMD-Compliance
3321	KMD-Relocation Expense
3331	KMD-Franklin Central Region Administrati
3333	KMD-Public Affairs
3338	KMD-ILWTN Union City Operations
3341	KMD-Columbia Operations
3342	KMD-Franklin Operations
3343	KMD-Murfreesboro Operations
3344	KMD-Shelbyville Operations
3351	KMD-Paducah Operations
3352	KMD-Central Region South Compliance
3363	KMD-HR Benefit Variance
3434	KMD-Maryville Operations
3435	KMD-Greenville/Morristown Operations
3436	KMD-Johnson City Tri-Cities Operations
3438	KMD-New River North Operations
3439	KMD-New River South Operations
3444	KMD-Pipeline Integrity Management
3450	KMD-Franklin Operations
3451	KMD-Johnson City Tri-Cities/Gaffney Admi
3533	Use 3333 Mid St Div South Public Affairs
3534	KMD- Gainesville-C&M/Service
3535	KMD-Columbus Operations

Cost Center	Description
3536	KMD-Columbus-Construction
3537	KMD-Columbus-Service
3561	KMD-Columbus Sub Region Lng
3562	KMD-Georgia Cast Iron Replacement
3563	KMD-Gainesville BareSteel
4016	LA Div Eastern Region Administrative
4032	LA Div Eastern Sales
4034	LA Div East Jefferson Service
4035	LA Div West Jefferson Service
4036	LA Div River Parishes Service
4037	Use 2473 LA Div St Bernard Service
4039	LA Div East Jefferson C&M # 1
4040	LA Div East Jefferson C&M # 2
4041	LA Div West Jefferson C&M # 1
4042	LA Div West Jefferson C&M # 2
4043	LA Div St Bernard C&M
4044	LA Div River Parishes C&M
4050	LA Div North Lake Operations
4051	LA Div Metro West Operations - C&M
4066	LA Div Gas Procurement
4101	MDTX-President
4102	MDTX-Information Technology
4103	MDTX-Human Resources
4104	MDTX-Regulatory
4105	MDTX-Facilities
4106	MDTX-Technical Services Admin
4107	MDTX-Finance
4108	MDTX-Marketing
4109	MDTX-Gas Measurement Project Management
4111	MDTX-Claims
4113	MDTX-Public Affairs
4118	MDTX-Environmental & Supply Chain
4119	MDTX-Regulatory & Compliance
4121	MDTX-Relocation Expense
4122	MDTX-Gas Measurement Analysis
4123	MDTX-Gas Measurement Engineering & Lab
4124	MDTX-Construction Management Dallas-Nort
4125	MDTX-Engineering Services Northeast
4126	MDTX-Engineering Services South
4127	MDTX-Engineering Services West
4128	MDTX-Engineering Services Programs
4129	MDTX-Engineering Services Admin
4131	MDTX-Operations-Southwest Region Admin
4133	MDTX-Abilene Area Public Affairs
4136	MDTX-Fort Worth Area Public Affairs
4137	MDTX-Plano Area Public Affairs
4138	MDTX-Dallas Area Public Affairs
4140	MDTX-Gas Storage & Compression
4141	MDTX-Asset Management
4144	MDTX-Corrosion & Integrity
4145	MDTX-Operations Support
4147	MDTX-Safety
4149	MDTX-SCADA/RTU
4153	MDTX-Distribution GIS (South)
4154	MDTX-Info Mgt
4155	MDTX-Right of Way
4160	MDTX-GS&D Contract Administration Supply
4163	MDTX-GS&D Marketing Manager
4164	MDTX-GS&D Industrial Marketing
4165	MDTX-North Reg West Area Dir Admin
4166	MDTX-SE Region Meter Reading
4167	MDTX-Ft Worth-SW Region Meter Reading
4168	MDTX-Garland District Meter Reading
4169	MDTX-North Reg Carrollton West District
4170	MDTX-Grand Prairie District Meter Readin
4171	Use 4247 - MDTX-North Region Meter Readi
4172	MDTX-SW Region Round Rock Central
4173	MDTX-SW Region Sweetwater District
4174	MDTX-Southeast Region Groesbeck District
4175	MDTX-West Storage & Compression
4176	MDTX-East Storage & Compression
4231	MDTX-North Reg Admin
4232	MDTX-North Reg Compliance East
4233	MDTX-North Reg Compliance WF
4234	MDTX-SE Reg Compliance ATH/LNG/COR
4235	MDTX-SE Reg Athens District
4237	MDTX-North Reg Greenville District
4239	MDTX-SE Reg Longview District
4241	MDTX-North Reg Paris District
4243	MDTX-North Reg Sherman District C&M
4244	MDTX-North Reg Sherman District CS
4245	MDTX-North Reg Wichita Falls District
4246	MDTX-North Reg Wichita Falls District Ce
4247	MDTX-North Reg Compliance SHE/PAR
4330	MDTX-SE Region South Director Admin
4331	MDTX-SW Region West Director Admin
4332	MDTX-SE Reg Compliance BRY/GRO/KAT
4333	MDTX-SW Reg Compliance South
4334	MDTX-SE Reg Compliance WAS/DES
4335	MDTX-SE Reg Bryan North
4336	MDTX-SE Reg Bryan South
4337	MDTX-SW Region Round Rock West
4338	MDTX-SW Region Round Rock East

Cost Center	Description
4339	MDTX-SE Reg Corsicana District
4340	MDTX-SE Region South Mgr
4341	MDTX-SW Reg Temple District
4342	MDTX-SW Reg Killeen District
4343	MDTX-SE Reg Waco South
4344	MDTX-SE Reg Waco NE
4345	MDTX-SE Reg East Mgr
4346	MDTX-SE Reg Waco NW
4347	MDTX-SW Region South Mgr
4431	MDTX-SW RegionWest Director Admin
4432	MDTX-SW Reg Compliance EAS
4433	MDTX-SW Reg Compliance ABL
4434	MDTX-SW Reg Abilene District C&M
4435	MDTX-SW Reg Abilene District CS
4436	MDTX-SW Reg Kerrville District
4437	MDTX-SW Reg San Angelo District C&M
4438	MDTX-SW Reg Brownwood Districtg Brownwoo
4439	MDTX-SW Reg Stephenville District
4440	MDTX-SW Reg Eastland District
4441	MDTX-SW Reg San Angelo District CS
4442	MDTX-SW Region West Mgr
4531	MDTX-SE Region Admin
4532	MDTX-SE Reg Mesquite District
4541	MDTX-SE Reg Dallas Director Admin
4542	MDTX-Pressure Control
4543	MDTX-SE Reg Compliance GAR
4544	MDTX-North Reg Compliance DEN/BOYD
4545	MDTX-SE Reg Compliance DAL
4546	MDTX-SW Reg Compliance FW
4547	MDTX-SW Reg CNG Operations
4548	MDTX-SW Reg Compliance ARL/IRV
4561	MDTX-North Reg East Area Dir Admin
4562	MDTX-SE Region Dallas Area Mgr
4563	MDTX-North Reg McKinney DistrictNorth Re
4564	MDTX-North Reg Plano District CS
4565	MDTX-SE Reg Garland District
4566	MDTX-SE Reg Rockwall District
4567	MDTX-SW Reg Ft Worth Area Mgr
4570	MDTX-North Reg East Area Mgr
4571	MDTX-SE Reg Dallas C&M North
4572	MDTX-SE Reg Dallas C&M South
4573	MDTX-SE Reg Dallas CS North
4574	MDTX-SE Reg Dallas CS Central
4575	MDTX-SE Reg Dallas CS South
4576	MDTX-SE Reg Dallas C&M Central
4581	MDTX-SW Reg Ft Worth/Arlington Director
4582	MDTX-North Reg West Area Mgr
4583	MDTX-SW Region Arlington Area Mgr
4584	MDTX-SE Reg DeSoto District
4585	MDTX-SE Reg Waxahachie District
4586	MDTX-North Reg Plano District C&M
4587	MDTX-SW Reg Arlington District CS
4588	MDTX-SW Reg Irving District
4590	MDTX-SE Region East Director Admin
4591	MDTX-SW Reg Arlington District C&M
4592	MDTX-North Reg Denton District
4593	MDTX-North Reg HEB District
4594	MDTX-North Reg Carrollton East District
4595	MDTX-North Reg Boyd District
4596	MDTX-SW Reg Fort Worth CS North
4597	MDTX-SW Reg Fort Worth CS South
4598	MDTX-SW Reg Fort Worth C&M North
4599	MDTX-SW Reg Fort Worth C&M South
4600	MDTX-Compliance Monitoring
4601	MDTX-Compliance Reporting
4602	MDTX-Asset Records
4603	MDTX-Construction Management Southwest
4604	MDTX-Compliance Integrity
4605	MDTX-Compliance Engineering
4606	MDTX-Finance Admin
4607	MDTX-Engineering Svc Dal-NW
4608	MDTX-Garland SC
4609	MDTX-North Reg McKinney District CS
4610	MDTX-Distribution GIS (North)
5001	MS Div Jackson Administration
5002	MS Div Jackson Information Services
5003	MS Div Jackson Human Resources
5004	MS-Jackson Regulatory Affairs
5005	MS Div Technical Services
5006	MS Div Jackson Engineering
5007	MS Div Jackson Finance
5008	MS Div Jackson Marketing
5009	MS Div Jackson Measurement Center
5018	MS-Safety-Tech Services
5019	MS Div Jackson Meter Reading
5021	MS Div Relocation Expense
5031	MS Div Southern Region Admin
5032	MS Div South Region Marketing
5033	MS Div Public Affairs
5034	MS Div Greenville
5035	MS Div Indianola
5038	MS Div Yazoo City
5039	MS Div Meridian

Cost Center	Description
5040	MS Div Natchez
5067	MS Div Supply Chain
5068	MS Div Industrial Drive
5070	MS Div Jackson Summary
5071	MS Div Jackson Service
5072	MS Div Jackson Local Office Operations
5073	MS Div Jackson Construction
5091	MS Div Building Services
5093	MS Div Operating Services
5096	MS Div Jackson District Vehicle Shop
5099	MS PBR
5131	MS Div Northern Region Admin
5132	MS Div North Region Marketing
5134	MS Div Southaven
5135	MS Div Clarksdale
5136	MS Div Cleveland
5139	MS Div Greenwood
5140	MS Div Grenada
5142	MS Div Kosciusko
5144	MS Div Louisville
5145	MS Div Columbus
5146	MS Div Starkville
5148	MS Div Westpoint
5163	MS Div HR Benefit Variance
5170	MS Div Tupelo
5171	MS Div Amory
5172	MS Div Amory Storage
5173	MS Div Goodwin Storage Field
8401	AEP-Corporate
8501	UCG Storage-Corporate
8502	UCG Storage-Barnsley, KY
8503	UCG Storage-Kansas
8520	Atmos Pipeline & Storage Corporate (Form
8530	WKG Storage-Corporate
8531	WKG Storage-East Diamond
8534	WKG Storage-Tar Spring Storage Field
8540	TLGS-Corporate
8550	TLIG-Corporate
8551	TLIG-Administration
8555	TLIG-Operations
8560	Woodward-Corporate
8561	AEH Corporate
8562	AEH Financial Reporting
8564	AEH Gas Accounting
8565	AEH Information Technology
8566	AEH Contracts and Trading
8567	AEH Risk Analysis
8568	AEH Credit & Finance
8569	AEH HR & Administration
8570	AEH Marketing
8571	AEH Customer Service
8572	AEH Marketing-Dallas
8573	AEH Marketing-Franklin
8574	AEH Marketing-New Orleans
8575	AEH Origination
8576	AEH Storage and Structuring
8577	AEH Trading
8578	AEH Transportation & Scheduling
8579	AEH Gas Supply
8580	AEH Business Development
8581	AEH Producer Services
8582	AEH Field Operations
8583	AEH-Service Committee
8584	AEH Olathe Marketing
8585	AEH National Accounts
8586	AEH Norfolk, VA
8599	AEH General Office
8600	Atmos Power Systems Inc (Previously Atmo
8601	Power Systems
8640	Western Kentucky Energy Services-Corpora
8650	United Cities Energy Services-Corporate
8701	AEM-Corporate
8702	AEM-Woodward
8703	AEM-Relocation
8801	Egasco-Corporate
8900	Nonregulated Financial Services
9001	TLGP-Lafayette Region
9002	TLGP- Administration
9003	TLGP- Gas Procurement
9006	TLGP- Operations
9008	TLGP- Pine Pipeline
9110	AES-Retail Services
9130	AES-Eastern Region
9140	AES-Southwest Region
9300	MS Energy
9601	APT-SE Region South Mgr
9602	APT-SW Region West Mgr
9603	APT-Gas Mktg & Transportation
9604	APT-Industrial Gas Mktg & Transportation
9605	APT-SW Region South Mgr
9606	APT-Contract Administration
9607	APT-Pipeline Marketing
9608	APT-North Reg Carrollton West District

Cost Center	Description
9611	APT-Information Technology
9612	APT-Gas Control
9613	APT-Gas Scheduling
9614	APT-Gas Control Operations
9618	APT-Distribution GIS (South)
9619	APT-Engineering Services Programs
9620	APT-Regulatory
9621	APT-President
9622	APT-Human Resources
9624	APT-Engineering Director Admin
9625	APT-Finance
9626	APT-Marketing
9627	APT-Gas Measurement Project Management
9628	APT-Claims
9629	APT-Public Affairs
9634	APT-Environmental & Supply Chain
9635	APT-Regulatory & Compliance
9636	APT-Gas Measurement Analysis
9637	APT-Gas Measurement Engineering & Lab
9638	APT-Construction Management Dallas-North
9639	APT-Engineering Services Northeast
9640	APT-Engineering Services South
9641	APT-Engineering Service West
9642	APT-SW Region Admin
9643	APT-Gas Storage & Compression
9644	APT-Asset Management
9645	APT-Corrosion & Integrity
9646	APT-Operations Support
9648	APT-Safety
9650	APT-SCADA/RTU Operations
9652	APT-Info Mgt
9653	APT-Right of Way
9654	APT-North Reg Admin
9655	APT-North Reg Compliance East
9656	APT-North Reg Compliance WF
9657	APT-SE Reg Compliance ATH/LNG/COR
9658	APT-SE Reg Athens District
9659	APT-North Reg Greenville District
9660	APT-SE Reg Longview District
9661	APT-North Reg Paris District
9662	APT-North Reg Sherman District C&M
9663	APT-North Reg Wichita Falls District
9664	APT-SW Region South Director Admin
9665	APT-SE Reg Compliance BRY/GRO/KAT
9666	APT-SW Reg Compliance South
9667	APT-SE Reg Compliance WAC/DES
9668	APT-SE Reg Bryan North
9669	APT-SW Region Round Rock West
9670	APT-SE Reg Corsicana District
9671	APT-SW Reg Temple District
9672	APT-SE Reg Waco South
9673	APT-SW Region West Director Admin
9674	APT-SW Reg Compliance EAS
9675	APT-SW Reg Compliance ABL
9676	APT-SW Reg Abilene District C&M
9677	APT-SW Reg Kerrville District
9678	APT-SW Reg San Angelo District C&M
9679	APT-SW Reg Brownwood Districteg Brownwoo
9680	APT-SE Region Admin
9681	APT-Pressure Control
9682	APT-SE Reg Compliance GAR
9684	APT-North Reg East Area Dir Admin
9685	APT-North Reg East Area Mgr
9686	APT-SW Region Ft Worth/Arlington Dir
9687	APT-North Reg West Area Mgr
9688	APT-North Reg Plano District C&M
9689	APT-SE Region East Director Admin
9690	APT-Technical Service Admin
9691	APT-Northside Loop
9692	APT-Relocation Expenses
9694	APT-SW Reg Killeen District
9695	APT-SE Region South Director Admin
9696	APT-SW Region Arlington Area Mgr
9697	APT-North Reg Denton District
9698	APT-North Reg HEB District
9699	APT-SE Reg Mesquite District
9700	Blueflame
9701	APT-SW Reg Irving District
9702	APT-SE Reg Bryan South
9703	APT-SE Reg Waco NE
9704	APT-North Reg Wichita Falls District Cen
9705	APT-North Reg Sherman District CS
9706	APT-North Reg Plano District CS
9707	APT-SW Region Round Rock East
9711	APT-Abilene Area Public Affairs
9714	APT-Ft Worth Area Public Affairs
9715	APT-Plano Area Public Affairs
9716	APT-Dallas Area Public Affairs
9720	APT-North Reg McKinney District
9721	APT-SE Reg Garland District
9722	APT-SW Reg Arlington South
9723	APT-SE Reg Rockwall District
9733	APT-Asset Records

Cost Center	Description
9734	APT-SE Reg Waco NWAPT-SE Reg Waco NW
9735	APT-Ft Worth CS North
9736	APT-Ft Worth CS South
9737	APT-North Reg Carrollton East District
9738	APT-North Reg Boyd District
9739	APT-SW Reg Fort Worth C&M North
9740	APT-SW Reg Fort Worth C&M South
9741	APT-SW Region Round Rock Central
9745	APT-SE Reg DeSoto District
9746	APT-SE Reg Waxahachie District
9747	APT-SW Reg Arlington District C&M
9748	APT-Compliance Monitoring
9749	APT-Compliance Reporting
9751	APT-SE Reg Dallas C&M Central
9760	APT-SW Reg Eastland District
9765	APT-North Reg Compliance SHE/PAR
9770	APT-SE Reg Groesbeck District
9775	APT-SW Reg Sweetwater District
9776	APT-SW Reg Stephenville District
9777	APT-SW Reg San Angelo District CS
9778	APT-SW Reg Abilene District CS
9780	APT-Construction Management Southwest
9781	APT-Compliance Integrity
9782	APT-Compliance Engineering
9783	APT- Finance Admin
9784	APT-Engineering Svc Dal-NW
9802	APT-North Reg Compliance DEN/BOYD
9803	APT-SW Reg Compliance FW
9804	APT-SW Reg CNG Operations
9806	APT-North Reg West Area Dir
9808	APT-SE Reg East Area Mgr
9809	APT-SW Region Ft Worth Area Mgr
9810	APT-SW Compliance ARL-IRV
9811	APT-West Storage & Compression
9812	APT-East Storage & Compression
9813	APT-Garland CS
9814	APT-North Reg McKinney District CS
9815	APT-Distribution GIS (North)
9816	APT-Pipeline Marketing Contract Administ
9820	Phoenix Gas Gathering Company
9825	Atmos Gathering Company
9830	HNNG
9840	Ft. Necessity, LLP
9890	Blueflame Elim
9891	AEC Elim

DOCKET NO. 14-00146
ATTACHMENT 1
TO MFR NO. 1-05

Account	Description
1010	Gas Plant in Service
1011	Property under Capital Leases
1020	Gas plant purchased or sold
1060	Completed construction not cla
1070	Construction work in progress
1080	Accum Prov for Depreciation
1081	Accumulated provision for depr
1110	Accumulated Provision for Amor
1140	Gas plant acquisition adjustme
1150	Accumulated provision for amor
1160	Other gas plant adjustments
1170	Gas stored underground-Noncurr
1171	Gas stored-base gas
1210	Nonutility property
1220	Accumulated provision for amor
1230	Investment in associated compa
1231	Investment in subsidiary compa
1240	Other investments
1280	Other special funds
1310	Cash
1340	Other special deposits
1341	Other special deposits
1360	Temporary cash investments
1410	Notes receivable
1420	Customer accounts receivable
1430	Other Accounts Receivable
1440	Accum prov for uncollectible a
1460	A/R from Associated Companies
1510	Fuel stock
1530	Residuals and Extracted Produc
1540	Plant Materials and Operating
1550	Merchandise
1560	Other Materials and Supplies
1630	Stores Expense Undistributed
1641	Gas stored underground-Current
1642	Liquefied natural gas stored
1643	Natural Gas Held for Processin
1650	Prepayments
1710	Interest and Dividends Receiva
1720	Rents receivable
1730	Accrued utility reserves
1740	Miscellaneous current and accr
1810	Unamortized debt expense
1823	Other Regulatory Assets
1840	Clearing Account
1860	Miscellaneous deferred debits
1890	Unamortized Loss on Reacquired
1900	Accumulated Deferred Income Ta
1910	Unrecovered Purchased Gas Cost
2010	Common stock issued
2020	Common stock subscribed
2070	Premium on capital stock
2110	Miscellaneous paid-in capital
2140	Capital stock expense
2150	Appropriated Retained Earnings
2160	Retained Earnings
2170	Reacquired stock
2210	Bonds
2220	Reacquired Bonds
2240	Other long-Term
2260	Long Term Debt Discount
2270	Obligations under Capital Leas
2281	Accumulated provision for prop
2282	Accumulated provision for inju
2284	Accumulated miscellaneous oper
2310	Notes payable
2320	Accounts Payable
2340	Accounts payable to associated
2350	Customer deposits
2360	Taxes accrued
2361	Taxes accrued FABS
2370	Interest accrued
2380	Dividends declared
2410	Tax collections
2420	Miscellaneous current and accr
2430	Obligations under Capital Leas
2520	Customer advances for construc
2530	Other deferred credits
2540	Other Regulatory Liabilities
2550	Accumulated deferred investmen
2710	Contributions in aid of constr
2820	Accum deferred income taxes-Ot
2830	Accumulated deferred income ta
4030	Depreciation Expense
4041	Amortization and depletion of
4042	Amortization of Underground St
4043	Amortization of Other Limited-
4050	Amortization of other gas plan
4060	Amortization of gas plant acqu
4071	Amortization of property losse
4073	Regulatory Debits
4074	Regulatory Credits
4081	Taxes other than income taxes,

Account	Description
4091	Income taxes, utility operatin
4093	Income taxes, Change in accoun
4101	Provision for deferred income
4114	Investment tax credit adjustme
4150	Revenues from Merchandising, J
4160	Costs and Expenses of Merchand
4170	Revenues from nonutility opera
4190	Interest and dividend income
4191	Allowance for other funds used
4210	Miscellaneous nonoperating inc
4211	Gain on Disposition of Propert
4212	Loss on Disposition of Propert
4250	Miscellaneous amortization
4261	Donations
4263	Penalties
4264	Civic, Political and Related
4265	Other deductions
4270	Interest on long-Term debt
4280	Amortization of debt discount
4281	Amortization of loss on reacqu
4300	Interest on debt to associated
4310	Other interest expense
4320	Allowance for borrowed funds u
4350	Change in accounting principle
4380	Dividends declared-Common stoc
4800	Residential sales
4805	Unbilled Residential Revenue
4810	Commercial and Industrial Sale
4811	Commercial Revenue-Banner
4812	Industrial Revenue-Banner
4813	Irrigation Revenue-Banner
4814	Feedlot Revenue-Banner
4815	Unbilled Comm Revenue
4816	Unbilled Industrial Revenue
4817	Revenue from Lost Margin (gros
4818	Discount on Revenue from Lost
4819	Unbilled Irrigation Revenue
4820	Other Sales to Public Authorit
4825	Unbilled Public Authority Reve
4830	Sales for resale
4840	Interdepartmental Sales
4850	Intradepartmental Transfers
4861	Rental & Leasing Revenue
4862	Irrigation
4870	Forfeited discounts
4880	Miscellaneous service revenues
4890	Revenues from transportation o
4891	Revenue-Transportation Gatheri
4892	Revenue-Transportation Transmi
4893	Revenue-Transportation Distrib
4894	Revenue-Storing Gas Others
4895	Revenue-Transportation Commerc
4896	Revenue-Transportation Industr
4897	Revenue from Lost Margin (Gros
4898	Discount on Revenue from Lost
4900	Sales of products extracted fr
4910	Revenue Gas Processed by Other
4920	Incidental Gasoline and Oil Sa
4930	Rent from gas property
4940	Interdepartmental Rents
4950	Other gas revenues
4951	Other gas revenues (Unrealized
4952	Other Gas Revenues (Realized)
4960	Provision for Rate Refunds
4970	Intersegment elimination - Rev
7230	Fuel for liquefied petroleum g
7280	Liquefied petroleum gas
7330	Gas mixing expenses
7350	Miscellaneous production expen
7410	Production-Maintenance of stru
7420	Maintenance of production equi
7500	Production and gathering-Opera
7510	Production maps and records
7520	Gas wells expenses
7530	Field lines expenses
7540	Field compressor station expen
7550	Field compressor station fuel
7560	Field measuring and regulating
7570	Production and gathering-Purif
7580	Gas well royalties
7590	Production and gathering-Other
7610	Production and gathering-Maint
7620	Production and gathering-Maint
7640	Maintenance of field lines
7650	Maintenance of field compresso
7660	Maintenance of field measuring
7670	Production-Maintenance of puri
7690	Maintenance of other equipment
7700	Products extraction-Operation
7710	Products extraction-Operation
7720	Gas shrinkage
7730	Production-Fuel
7740	Power

Account	Description
7770	Gas processed by others
7840	Products extraction-Maintenanc
7860	Maintenance of extraction and
8000	Natural gas well head purchase
8001	Intercompany Gas Well-head Pur
8010	Natural gas field line purchas
8020	Natural Gas Purchases-Gas Plan
8030	Natural gas transmission line
8031	Cost of Consumer Sales
8032	Cost of Commercial/Industrial
8033	Cost of Rental & Leasing Reven
8034	Cost of Irrigation Sales
8035	Cost of Storage Revenues
8040	Natural gas city gate purchase
8041	Liquefied Natural Gas Purchase
8045	Transportation to City Gate
8050	Other purchases
8051	PGA for Residential
8052	PGA for Commercial
8053	PGA for Industrial
8054	PGA for Public Authorities
8055	PGA for Irrigation Sales
8056	PGA for Interdepartmental Sale
8057	PGA for Transportation Sales
8058	Unbilled PGA Cost
8059	PGA Offset to Unrecovered Gas
8060	Exchange gas
8070	Purchased gas expenses
8071	Well Expenses-Purchased Gas
8072	OPS Purchased Gas Measuring St
8073	MAINT Purchased Gas Measuring
8074	Purchased Gas Calculations Exp
8075	Other Purchased Gas Expenses
8081	Gas withdrawn from storage-Deb
8082	Gas delivered to storage-Credi
8091	Withdrawals-Gas Held for Proce
8092	Deliveries-Gas Held for Proces
8100	Gas Used for Compressor Statio
8101	Gas Used for Compressor Statio
8110	Gas used for products extracti
8120	Gas used for other utility ope
8121	Gas used for other utility ope
8130	Other gas supply expenses
8131	Other gas supply expenses (Rea
8135	Intersegment elimination - Gas
8140	Storage-Operation supervision
8150	Storage-Maps & Records
8160	Wells expenses
8170	Lines expenses
8180	Compressor station expenses
8190	Compressor station fuel and po
8200	Storage-Measuring and regulati
8210	Storage-Purification expenses
8230	Gas losses
8240	Storage-Other expenses
8250	Storage well royalties
8260	Storage-Rents
8300	Storage-Maint Supervision & En
8310	Storage-Maintenance of structu
8320	Maintenance of reservoirs and
8330	Maintenance of lines
8340	Maintenance of compressor stat
8350	Maintenance of measuring and r
8360	Processing-Maintenance of puri
8370	Maintenance of other equipment
8400	Other storage-Operation superv
8410	Other storage expenses-Operati
8420	Other storage-Rents
8431	Other storage-Maintenance supe
8432	Other storage-Maintenance of s
8433	Maintenance of gas holders
8435	Maintenance of liquefaction eq
8436	Maintenance of vaporizing equi
8500	Transmission-Operation supervi
8510	System control and load dispat
8520	Communication system expenses
8530	Transmission-Compressor statio
8540	Gas for compressor station fue
8550	Other fuel & power for compres
8560	Mains expenses
8570	Transmission-Measuring and reg
8580	Transmission and compression o
8590	Transmission-Other expenses
8600	Transmission-Rents
8610	Transmission-Maintenance super
8620	Transmission-Maintenance of st
8630	Transmission-Maintenance of ma
8640	Transmission-Maintenance of co
8650	Transmission-Maintenance of me
8660	Transmission-Maintenance of co
8670	Transmission-Maintenance of ot
8700	Distribution-Operation supervi
8710	Distribution load dispatching

Account	Description
8711	Odorization
8720	Distribution-Compressor statio
8740	Mains and Services Expenses
8750	Distribution-Measuring and reg
8760	Distribution-Measuring and reg
8770	Distribution-Measuring and reg
8780	Meter and house regulator expe
8790	Customer installations expense
8800	Distribution-Other expenses
8810	Distribution-Rents
8850	Distribution-Maintenance super
8860	Distribution-Maintenance of st
8870	Distribution-Maint of mains
8880	Maintenance of compressor stat
8890	Maintenance of measuring and r
8900	Maintenance of measuring and r
8910	Maintenance of measuring and r
8920	Maintenance of services
8930	Maintenance of meters and hous
8940	Distribution-Maintenance of ot
9010	Customer accounts-Operation su
9020	Customer accounts-Meter readin
9030	Customer accounts-Customer rec
9040	Customer accounts-Uncollectibl
9050	Customer accounts-Miscellaneou
9070	Customer service-Supervision
9080	Customer service-Operating ass
9090	Customer service-Operating inf
9100	Customer service-Miscellaneous
9110	Sales-Supervision
9120	Sales-Demonstrating and sellin
9130	Sales-Advertising expenses
9160	Sales-Miscellaneous sales expe
9200	A&G-Administrative & general s
9210	A&G-Office supplies & expense
9220	A&G-Administrative expense tra
9221	A&G-Admin exp transferred to N
9230	A&G-Outside services employed
9240	A&G-Property insurance
9250	A&G-Injuries & damages
9260	A&G-Employee pensions and bene
9270	A&G-Franchise requirements
9280	A&G-Regulatory commission expe
9290	A&G-Duplicate charges-Cr
9301	A&G-General advertising expens
9302	Miscellaneous general expenses
9310	A&G-Rents
9320	A&G-Maintenance of general pla

Sub Account	Description
00000	Default
01000	Non-project Labor
01001	Capital Labor
01002	Capital Labor Contra
01003	Deferred Project Labor
01004	Deferred Project LaborContra
01005	Capitalized Project Labor
01006	O&M Project Labor andContra
01008	Expense Labor Accrual
01009	Capital Labor Accrual
01010	PTO Accrual
01011	Capital Labor TransferIn
01012	Capital Labor TransferOut
01013	Expense Labor TransferIn
01014	Expense Labor TransferOut
01015	Deferred Project LaborTransfer In
01016	Deferred Project LaborTransfer Out
01200	Other Benefits Load
01201	Other Benefits Variance
01202	Pension Benefits Load
01203	OPEB Benefits Load
01206	Pension Benefits Variance
01207	OPEB Benefits Variance
01208	Workers Comp BenefitsVariance
01210	Fica Load
01211	Futa Load
01212	Suta Load
01213	Fica Load Accrual
01214	Futa Load Accrual
01215	Suta Load Accrual
01219	Kentucky Local Tax
01220	Denver City Tax Load
01221	Workers Comp BenefitsLoad
01223	SERP Reg Asset Amort
01226	Pension Regulated Asset O&M
01227	OPEB Regulated Asset O&M
01228	SERP Regulated Asset O&M
01229	Pension Reg Asset Amort
01230	OPEB Reg Asset Amort
01239	Employer 401K Expense
01251	Medical Benefits Load
01252	Medical Benefits Variance
01253	Medical Benefits Projects
01256	Payroll Tax Projects
01257	ESOP Benefits Load
01258	ESOP Benefits Variance
01259	ESOP Benefits Projects
01260	HSA Benefits Load
01261	HSA Benefits Variance
01262	HSA Benefits Projects
01263	RSP FACC Benefits Load
01264	RSP FACC Benefits Variance
01265	RSP FACC Benefits Projects
01266	Life Benefits Load
01267	Life Benefits Variance
01268	Life Benefits Projects
01269	LTD Benefits Load
01270	LTD Benefits Variance
01271	LTD Benefits Projects
01290	Other Benefits Projects
01291	Pension Benefits Projects
01292	OPEB Benefits Projects
01293	Workers Comp BenefitsProjects
02001	Inventory Materials
02002	Material Cost - MajorItems
02003	Material Cost - Other
02004	Warehouse Loading Charge
02005	Non-Inventory Supplies
02006	Purchasing Card Charges
03001	Vehicle Depreciation Capitalized
03002	Vehicle Lease Payments
03003	Capitalized transportation costs
03004	Vehicle Expense
04001	Safety, Newspaper
04002	Required By Law, Safety
04017	Promo Sales, ConsumerRel
04018	Safety
04021	Promo Other, Misc
04022	Promo Sales, Misc
04023	GCA Public Notice Publication
04030	Energy Efficiency - Residential
04038	Natural Gas Vehicle Demo
04040	Community Rel&Trade Shows
04041	Gas Light Relight Program
04044	Advertising
04046	Customer Relations & Assist
04065	Offsite Storage
04069	Blueflame Property Insurance
04070	Insurance-Other
04072	Insurance Capitalized
04111	Director's Fees
04112	Board Meeting Expenses
04113	Directors Retirement Expenses

Sub Account	Description
04120	Newswire/Blast Fax/Mail List
04121	Inv Relations/Bnkg Inst
04122	Annual Report Design,Printing & Dist.
04124	Fin Notice & Qtrly Rpt
04125	Proxy Solicitation Exp
04126	Transfer Agent Administration
04127	Tr & Reg of Bonds/DebtFee
04129	NYSE Fees & Exps
04130	Bank Service Charge
04135	Reimbursement of FraudPayments
04140	Analyst Activities
04141	Web Site
04145	Printing/Slides/Graphics
04146	Public Relations
04201	Software Maintenance
04212	IT Equipment
04301	Equipment Lease
04302	Heavy Equipment
04306	Parts
04307	Heavy Equipment Capitalized
04580	Building Lease/Rents Capitalized
04581	Building Lease/Rents
04582	Building Maintenance
04585	Railroad easements andcrossings
04590	Utilities
04592	Misc Rents
04593	Leased Gas Districts
04595	Refurbished Meters
04596	Utilities not allocated
04599	Capitalized Utility Costs
04737	Curtailment Overpull Fee
04740	Cashouts
04741	Triangle Shipper Cashouts
04743	Hedging Settlements
04744	Exchange Gas
04745	Exchgas-Assoc-Retention Contra
04746	System gas Imbalance exp
04751	Gas Purchases
04753	Hedging
04755	Purchase Gas-Ind-Actual
04756	Storage Injection/Withdrawal
04760	Estimated Gas Cost
04771	Demand Charges-Transportation
04772	Commodity-Transportation
04773	Demand-Storage
04774	Capacity Release
04775	PGA Recoveries
04776	Imbalances
04777	Realignment Costs
04780	Other Gas Costs
04782	Bolivar-Hickory ValleySubstation
04783	Gas Commissions
04784	Gas Cost - Nonaff
04785	Gas Cost - Aff
04786	Storage Hedges
04787	FP Basis Swaps
04788	Customer Settlements (Fin'l Trades)
04789	Futures Allocations
04792	Gas Transport Cost - Nonaff
04793	Gas Transport Cost-Aff
04794	Gas Storage Cost-Nonaff
04795	Gas Storage Cost-Aff
04797	Line of Credit Fees
04799	Compressor Repairs/Maint
04800	Reimbursement for GasLoss
04801	Company Used Gas
04802	PGA Recoverable Company Used Gas
04819	Unbilled PGA-Res
04820	Unbilled PGA-Comm
04821	Unbilled PGA-Ind
04822	Unbilled PGA-PA
04824	Other Gas Supply Exp O&M
04825	Trans/Comp Exp O&M-Atmos P/L Tx
04827	3rd Party Transport
04828	City Gate Service-Residential
04829	City Gate Service-Commercial
04830	City Gate Service-Industrial
04831	City Gate Service-Transport
04832	West Texas Irr unbilled est
04861	A&G Overhead
04862	A&G Overhead Load
04863	A&G Overhead Clearing
04871	WIP Closing
04873	WIP Interest Cap AFUDC
04881	WIP Salvage
04882	WIP Removal Cost
04888	Land
04889	Land Rights
05010	Office Supplies
05111	Postage/Delivery Services
05310	Monthly Lines and service
05312	Long Distance
05314	Toll Free Long Distance

Sub Account	Description
05316	Telecom Maintenance &Repair
05317	Telephone Directory
05323	Measurement & Meter Reading
05331	WAN/LAN/Internet Service
05351	AMI Tower Rent
05352	AMI Tower Fees
05364	Cellular, radio, pagercharges
05376	Cell service for MDT's, PC's, SCADA and
05377	Cell phone equipment and accessories
05380	Video Conference
05390	Audio Conference
05399	Capitalized Telecom Costs
05411	Meals and Entertainment
05412	Spousal & Dependent Travel
05413	Transportation
05414	Lodging
05415	Membership Fees
05416	Club Dues - Nondeductible
05417	Club Dues - Deductible
05418	Settlement
05419	Misc Employee Expense
05420	Employee Development
05421	Training
05422	Operator Qualifications Training
05424	Books & Manuals
05425	Regulatory ComplianceTraining
05426	Safety Training
05427	Technical (Job Skills)Training
05428	Computer Skills & Systems Training
05429	Work Environment Training
05430	Gas Supplies Services
06111	Contract Labor
06112	Collection Fees
06116	Bill Print Fees
06121	Legal
07111	Damages
07115	Insurance Reserve
07119	Insurance - D&O
07120	Environmental & Safety
07121	Insurance - Public Liability
07421	Service Awards
07443	Uniforms
07444	Uniforms Capitalized
07447	Education Assistance Program
07449	Non-Qual Retirment Exp
07450	Capitalized RestrictedStock
07452	Variable Pay & Mgmt Incentive Plans
07453	Exec Compensation-Other
07454	VPP & MIP - Capital Credit
07458	Restricted Stock - Long Term Incentive
07460	RSU-Long Term Incentive Plan - Time Lap
07463	RSU-Managment Incentive Plan
07486	Rabbi Trust Gain/Loss
07487	COLI CSV & Premiums
07488	COLI Loan Interest
07489	NQ Retirement Cost
07490	SERP Capitalized
07495	Employee Broadcast andPublication
07499	Misc Employee WelfareExp
07510	Association Dues
07520	Donations
07590	Misc General Expense
07591	Supplies & Expense
07592	Vendor Comp Sales Tax
07600	CWIP Accruals
07601	Vehicle Cap Accrual
07602	Depreciation Cap Accrual
07603	Rent Cap Accrual
07604	Restricted Stock Cap Accrual
07605	Heavy Equipment Cap Accrual
07606	Insurance Cap Accrual
07607	Telecom Cap Accrual
07608	Uniform Cap Accrual
07609	Utility Cap Accrual
07612	Benefits Cap Accrual
07651	FAS 87 Cap Reg Asset
07652	FAS 106 Cap Reg Asset
07653	SERP Cap Reg Asset
09172	Receipt O/H Dr/Cr
09173	W/H Adjmnt - Dr/Cr
09174	W/H Obsolete Inv Adj
09176	Transferring Inventory
09195	Use only for HR exp default ***Formerly
09278	Storage O/H - Clearing
09341	Admin & General Expenses
09344	Depr & Taxes Other Expense
09345	Taxes Other Than Inc Tax
09910	Customer InstallationRev
09911	Reimbursements
09927	Cust Uncol Acct-WriteOff
10001	Lp - Production Plant
10002	Ng - Production Plant
10003	Ng - Storage Plant

Sub Account	Description
10004	Transmission Plant
10006	General Dist System Plant
10008	General Plant
10010	Great River Acquisition
10011	Acquisition Adj - Winn
10012	Acquisition Adj-Long Gas
10013	Amort-Acquisition Adj
10014	Amort-Acquisition Adj-Winn
10015	Amort-Acquisition Adj-Long
10016	Amort-Acquisition AdjOceana
10017	Acquisition Adj
10018	Acquisition Adj-Oceana
10021	Acquisition Adj-priorto purchase
10024	Acquisition Adj-MVG 1
10025	Acquisition Adj-MVG 2
10026	Beginning Balance Mid-Tex Assets
10027	Acquisition Adj-Mid-Tex
10028	MEC Payment
10029	Acquisition Adj-Bude &Meadville
10201	Nonutility Prop Ss#
10204	Investment in TLGP (Formerly TLIG)
10208	Inv/Assc-Aes Captl
10210	Investment UCGS
10211	Investment in Atmos Power Systems (Pre
10213	Inv in Nonregulated Shared Svc
10214	Investment in UC Propane
10217	Inv in MS Energy
10218	Investment in AEP-Atmos Exploration
10221	Investment in WKG Storage Inc
10222	Nonutility-Land
10223	Nonutility-Buildings &Improvements
10224	Nonutility-Furniture &Fixtures
10225	Nonutility-Communication Equipment
10226	Nonutility-Shop Equipment
10227	Nonutility-Transportation Equip-Rental
10228	Nonutility-Plant in Service
10229	Nonutility-Gas StoredUnderground-NC
10232	Investment in AEM-Atmos Energy Marketin
10233	Investment in Atmos Pipeline & Storage
10234	Investment in Enertrust Inc
10238	Investment in Egasco LLC
10242	Investment in WoodwardMarketing LLC
10248	East Diamond Storage Facility
10250	Inv in Blueflame Insurance
10256	Restricted Stock GrantValue--LTIP - Pe
10257	Restricted Stock Accumulated Amort--LTI
10260	RSU Grant Value - LTIPTime Lapse
10261	#NAME?
10264	RSU Grant Value - MIP
10265	#NAME?
10266	Investment in AGC
10267	RSU Grant Value - LTIPPBDEU
10312	Blueflame Investments
10350	Rent Deposits
10400	Cash-ANB 523
10408	Cash-AEC BOA 7500
10413	Cash-Fleet Dental
10437	Cash-3751029418 Storage
10438	Cash-3751029405
10465	BofA MM Savings - 4426854412
10466	BofA MM Savings - 4426854425
10468	Cash Payroll 82821
10483	AEH-Cash 3751371962
10485	APSI - Cash 3751371881
10486	WKG Storage Inc 3751371894
10487	Atmos Energy Services3751372000
10488	Egasco LLC 3751371991
10489	TLGP 3751371917
10490	AEPI-Cash 3751371904
10514	Cash-TLGS Inc BoA 3751592628
10515	Cash-ANB 00531
10517	Cash-Refunds ANB 82805
10518	Cash-Oracle AR BoA 3756617812
10530	Cash-TLIG BoA 3751849928
10533	Cash - AEM BOA 1125
10636	Cash-Blueflame BoB 822397
10638	Cash-Atmos Gathering BoA 4426357993
10639	Cash-US Bank 152308790418
10806	Auto Liability Loss Fund
10807	Flex Spending Deposit
10812	Mnt Crested Butte-Deposit
10832	County of Williamson
10834	BNP Paribas
10835	Docucorp Postage MeterDeposit
10876	Investment-Money Market
10911	Unbilled Revenue
10915	Mechanized Billing
10917	Unapplied CIS Payments
10918	Misc CIS Charges
10921	Special Billing-Gas Serv
10926	Oracle AR Gas Master
10928	Manual Revenue Accruals
10929	Reclass of Credit Balances

Sub Account	Description
10930	AR Transfers Between Customers
10937	Colorado PIPP Payments
10971	Misc
10990	Premium Receivable
10995	AR Trade-WMLLC
10996	Trade AR Pre PetitionBankruptcy (Forme
10997	Oracle AR Damage Claims
10998	Oracle AR UnidentifiedReceipts
10999	Oracle AR Other
11198	Interco Lending AEH/AEC
11199	Interco Lending AEH/AEM
11313	Misc - Cleared Currently
11317	Estimated A/R
11323	TBS-Accounts Receivable
11325	Commonwealth Storage Billings
11326	Meter Reading Charges
11339	Insurance Company Receivable
11342	Oracle AR Road Moves
11345	IBIS AR Estimate
11346	Employee Advances
11347	Employee Merchandise-Payroll Deduction
11350	Other A/R Emp PayrollDed
11351	Tuition Receivable
11354	La Interstate Gas Company
11358	Misc Accounts Receivable
11363	A/R- Undistributed NetIncome
11371	Roadmove Receivables
11373	Employee equity advance
11375	AEM- Ad Valorem Collections
12001	Beginning of Year Reserve
12003	Monthly Bad Debt Provision
12004	SAP Customer AR Writeoffs
12005	SAP Customer AR Recoveries
12008	Oracle AR Allowance -Other invoices
12009	Damage Claims-Oracle AR
12011	TBS Net write off
12012	TBS Provision
12147	Interco between AGC &HNNG Devel
12148	Line of Credit Intercompany
12700	Inventory Transfer toWest Texas
12701	Inventory Transfer toTransLa
12702	Inventory Transfer toKY
12703	Inventory Transfer toCOKS
12704	Inventory Transfer toUCG
12705	Inventory Transfer toMVG
12706	Inventory Transfer toMid-Tex
12707	Inventory Transfer toAPS
12800	FA Transfer
12900	Plnt M&S General
12906	Receiving Inventory
13000	Prepaid Expenses Misc
13001	Prepaid-Worker's CompIns
13003	Prepaid-Auto LiabilityIns
13004	Prepaid-Insurance-Other
13005	Prepaid-Insurance-D&O
13006	Prepaid Insurance-Public Liability
13007	Prepaid-La Occup Licenses
13009	Prepaid-Gross ReceiptTax
13010	Prepaid-Symantec Software
13012	Prepaid-COLI Ins Premium
13013	Prepaid-SS Mailroom Postage Machine
13015	Prepaid-Postage for Cust Billing
13019	Prepaid-Other WMLLC
13022	Prepaid Rent-Gilliland
13027	Prepaid-Southern Gas Dues
13028	Prepaid-American Gas Dues
13030	Prepaid-Ky Psc Assessment
13031	Prepaid-Co Puc Assessment
13035	Prepaid-Revolving Credit Facility
13041	Tennessee Regulatory Authority
13047	Prepaid-Bill PrintingSupplies
13054	Prepaid - Rent-LeasedGas Property
13060	Prepaid - Tx Tech
13067	Prepaid-Blueflame Property Insurance
13072	State Occupation Tax Prepayment
13073	Local Gross Receipts Prepayments
13083	Prepaid-RedHat Software
13089	Prepaid-BlueFlame Misc
13090	Prepaid DOT Fee/Right-of-way
13092	Prepaid Antispam Software Maint
13093	Prepaid Scanmail Software Maint
13111	Prepaid-Altiris
13118	Prepaid-MS Virtual Desktop
13123	Construction Materials& Services
13124	Ppd SW & HW Maint
13125	Ppd-Asset Mangement Plan
13126	Prepaid-Towers RewardsSystem
13127	Prepaid-Easement Rent
13128	Prepaid-KPMG InternalAudit
13401	Pipeline Imbalances
13403	Exchange Gas
13406	Stable Rate Revenue Accrual
13407	Misc Current & Accrued

Sub Account	Description
13499	Interest Receivable
13501	Med Terms Ser A-1
13521	150MM 6.75% due Jul-28
13529	500MM 4.95% due Oct-14
13530	200MM 5.95% due Oct-34
13531	250MM 6.35% due Jun-17
13532	450MM 8.5% due Mar-19
13533	8 1/2% Sr note due 2019-450MM
13534	400MM 5.5% due Jun-41
13535	500MM 4.15% due JAN 2043
13536	Oct-14 debt issuance costs
13537	Jun-17 debt issuance costs
13600	Benefits A Cr Exp Medical Load
13602	Benefits A Cr Exp ESOPLoad
13603	Benefits A Cr Exp EmpHSA Load
13604	Benefits A Cr Exp RSPFACC Load
13605	Benefits A Cr Exp Basic Life Load
13606	Benefits A Cr Exp LTDLoad
13607	Benefits B Medical Variance Clr
13609	Benefits B Emp ESOP Variance Clr
13610	Benefits B Emp HSA Variance Clr
13611	Benefits B RSP FACC Variance Clr
13612	Benefits B Emp Basic Life Variance Clr
13613	Benefits B Emp LTD Variance Clr
13614	Benefits C Gross TransMedical
13616	Benefits C Gross TransEmp ESOP
13617	Benefits C Gross TransEmp HSA
13618	Benefits C Gross TransRSP FACC
13619	Benefits C Gross TransBasic Life
13620	Benefits C Gross TransLTD
13621	Capital Benefits D True up Medical
13623	Capital Benefits D True up Emp ESOP
13624	Capital Benefits D True up Emp HSA
13625	Capital Benefits D True up RSP FACC
13626	Capital Benefits D True up Basic Life
13627	Capital Benefits D True up LTD
13628	Capital Benefits E CapTU offset Medica
13630	Capital Benefits E CapTU offset Emp ES
13631	Capital Benefits E CapTU offset Emp HS
13632	Capital Benefits E CapTU offset RSP FA
13633	Capital Benefits E CapTU offset Basic
13634	Capital Benefits E CapTU offset LTD
13635	Capital Benefits F Medical Load Clr
13636	Capital Benefits F Payroll Tax Load Clr
13637	Capital Benefits F EmpESOP Load Clr
13638	Capital Benefits F EmpHSA Load Clr
13639	Capital Benefits F RSPFACC Load Clr
13640	Capital Benefits F Basic Life Load Clr
13641	Capital Benefits F LTDLoad Clr
13642	Capital Benefits G Medical Trans out
13643	Capital Benefits G Payroll Tax Trans ou
13644	Capital Benefits G EmpESOP Trans out
13645	Capital Benefits G EmpHSA Trans out
13646	Capital Benefits G RSPFACC Trans out
13647	Capital Benefits G Basic Life Trans out
13648	Capital Benefits G LTDTrans out
13649	Expense Benefits H Medical Trans out
13650	Expense Benefits H Payroll Tax Trans ou
13651	Expense Benefits H EmpESOP Trans out
13652	Expense Benefits H EmpHSA Trans out
13653	Expense Benefits H RSPFACC Trans out
13654	Expense Benefits H Basic Life Trans out
13655	Expense Benefits H LTDTrans out
13656	Capital Benefits I Medical Trans in
13657	Capital Benefits I Payroll Tax Trans in
13658	Capital Benefits I EmpESOP Trans in
13659	Capital Benefits I EmpHSA Trans in
13660	Capital Benefits I RSPFACC Trans in
13661	Capital Benefits I Basic Life Trans in
13662	Capital Benefits I LTDTrans in
13663	Expense Benefits J Medical Trans in
13664	Expense Benefits J Payroll Tax Trans in
13665	Expense Benefits J EmpESOP Trans in
13666	Expense Benefits J EmpHSA Trans in
13667	Expense Benefits J RSPFACC Trans in
13668	Expense Benefits J Basic Life Trans in
13669	Expense Benefits J LTDTrans in
13670	Benefits K Medical Transfers
13671	Benefits K Payroll TaxTransfers
13672	Benefits K Emp ESOP Transfers
13673	Benefits K Emp HSA Transfers
13674	Benefits K RSP FACC Transfers
13675	Benefits K Basic LifeTransfers
13676	Benefits K LTD Transfers
13704	KS Ad Valorem-Current
13705	KS Ad Valorem-Future
13707	VA WNA
13714	Denton Settlement-PmtRecovery
13729	Pipeline Safety Fee
13733	TN environmental cleanup costs
13735	KS WNA
13741	CO DSM
13744	KS WNA Recovery

Sub Account	Description
13746	CO Rate Case
13750	KS Rate Case 2010
13756	FAS 87 Reg Asset
13757	FAS 106 Reg Asset
13758	Mid-Tex DARR Tariff
13759	Georgia GRAM Accrual
13760	SERP Reg Asset
13761	Kansas Rate Case 2012
13768	MAOP Records
13770	Dkt 10000 Rate Case Exp
13771	MTX Rate Case GUD 10194 Dallas
13772	MTX Rate Case GUD 10194 non-Dallas
13773	WTX Rate Case GUD 10100
13774	WTX Rate Case 2013 SOI
13800	Expense Advance Clearing
13801	Inventory/PA ClearingAccount
13803	Cap Benefits F Load Clr
13805	Employer P/R Taxes Clearing
13807	Cap Benefits F PensionLoad Clr
13808	Cap Benefits F FAS 106Load Clr
13809	Cap Benefits F WorkersComp Clr
13810	Employer FICA Clearing
13811	Employer FUTA Clearing
13812	Employer SUTA Clearing
13813	Employer Denver City Tax Clearing
13815	Benefits K Pension Transfers
13816	Benefits K FAS106 Transfers
13819	Benefits C Gross TransWorkers Comp
13820	Workers' Comp Clearing
13821	Basic Life Insurance Clearing
13822	FAS/106 Clearing
13823	Medical/Dental Insurance Clearing
13824	LTD Clearing
13826	Employer ESOP Matching
13827	ESOP-Other Clearing
13828	Pension Cost Clearing
13829	Deferred Asset Clearing
13830	Project Conversion Clearing
13832	Deferred Project Conversion Clearing
13834	Main Extension ProjectConversion Clear
13836	PA Entry Clearing
13838	1099 Entries
13841	Employer ESOP MatchingAccrual
13842	Capital Benefits I Transfer In
13844	Expense Benefits J Trans In
13846	Benefits K Transfers
13847	Misc
13848	Oracle AR Clearing
13850	Benefits A Cr Exp Workers Comp
13851	Benefits B Worker's Comp Variance Clr
13852	TBS AMR Equipment
13853	Mid Tex Taxes Other
13854	Benefits C Gross Trans
13857	AEH 401K match
13858	Lincoln Rent Clearing
13860	Clearing Account - Admin Fees for FSA
13861	RSP FACC
13863	Employer Match HSA
13864	SAP Cash Clearing US Bank
13865	SAP Cash Clearing ANBDraft
13866	SAP Cash Clearing Banner Refund
13867	PNF US Bank
13868	PNF ANB Draft
13870	Capital Benefits G Workers Comp Trans o
13871	Capital Benefits I Pension Trans In
13872	Capital Benefits I FAS106 Trans In
13873	Capital Benefits G Pension Trans out
13874	Capital Benefits G FAS106 Trans out
13875	Expense Benefits H Pension Trans out
13876	Expense Benefits H FAS106 Trans out
13877	Expense Benefits J Pension Trans In
13878	Expense Benefits J FAS106 Trans In
13879	SAP FIGL Document Overflow
13880	Benefits A Cr Exp LoadPension
13881	Benefits A Cr Exp LoadFAS106
13882	Capital Benefits E CapTU offset Pensio
13883	Capital Benefits E CapTU offset FAS106
13884	Benefits C Gross TransPension
13885	Benefits C Gross TransFAS106
13886	Capital Benefits D True up Pension
13887	Capital Benefits D True up FAS106
13889	Benefits B Pension Variance Clr
13890	Benefits B FAS106 Variance Clr
13891	Capital Benefits D True up WorkComp
13892	Capital Benefits E CapTU offset WorkCo
13893	Expense Benefits H Workers Comp Transfe
13895	Capital Benefits I Workers Comp Trans i
13897	Expense Benefits J Workers Comp Trans i
13899	Benefits K Workers Comp Transfers
13900	Deferred Asset Projects
13904	Goodwill
13931	Energy Efficiency Program
13941	Nashville NFL PSL Fee

Sub Account	Description
13942	Houston NFL PSL Fee
13945	Stock Issuance Costs
13953	Goodwill - Comfurt Gas
13956	Line Pack
13957	Def Dr - Payroll Clearing
13992	Deferred Retirement Costs
13993	Pension Assets Noncurrent
14000	MVG-Unbilled Jobbing Work
14001	Conservation Project Cost
14002	Kansas Rate Case
14031	UCG Ks Capacity Rel Rev
14032	Colorado Rate Case
14066	Kansas Hedging Program
14084	Gas Purchases
14087	PBR Recoveries
14088	Recoveries
14089	Unbilled Recoveries
14093	Goodwill-Woodward (Formerly Investment)
14132	COLI Cash surrender Value
14133	COLI Loans Against CSV
14135	Conservation Project Recoveries
14147	Goodwill - MVG Acquisition
14151	Customer Contracts
14152	Goodwill - Citizens Acquisition
14153	Investment in Pine Pipeline
14155	LGS Integration Costs
14160	WT Surcharge
14162	2 B Universal Shelf Registration
14163	Goodwill - Mid-Tex Acquisition
14167	FY14 Equity Offering
14177	BC Materials
14184	Lincoln II Construction Cost
14214	Sports Option #5
14216	Def Dr - Park City
14217	Def - Park City - contra
14218	Texas Rule 8
14219	CO PIPP Cost Accumulation
14220	Colorado PIPP Recoveries
14221	Myriant Lease Rec
15900	CIG No Notice
15901	P/L Stored Gas
15902	P/L Stored Gas Lig-La
15903	P/L Stored Gas Tnn-La
15904	P/L Stored Gas Sonat-La
15905	P/L Stored Gas Koch-La
15906	P/L Storage-Wng Tss
15909	P/L Stored Gas - K N Energy
15911	Reliant
15921	P/L Storage-Southern
15922	P/L Storage-Transco-Gss
15923	P/L Storage-Transco-Wss
15924	P/L Storage-Transco-Ess
15929	P/L Storage-Trunkline-Salem
15933	P/L Storage-Tenn Gas-Fs3981
15935	GS Under Amory Storage
15937	P/L Storage-Etn-Va Early
15938	Prepaid Comm Etn-Saltville
15939	GS Under Tenn Storage
15941	P/L Storage-Tex Ea-Gss
15946	GS Under Texas Eastern
15947	Lng Stored
15953	GS Under Untd Bisteneau
15956	P/L Storage Gas-Williams 545
15973	Bridgeline Storage Facility
15974	Acadian Storage Cavern
15975	Koch Storage
15976	GS Under Bear Creek-Sng
15977	Gulf South-ISS
15983	GS Under Muldon-Sng
15991	Fair Value Hedge Inv
15993	WMLLC Storage Gas
15995	Other Systems
15996	Oneok P/L Stored Gas
15997	GS Under Goodwin
15998	UG Stored Gas Kansas
15999	Consigned Inventory
16003	Gulf South -Woodward (NOPSI)
16005	TLGP Gas Stored Est
16006	East Diamond Storage Facility
16007	Huntsman Storage Facility
16008	Gulf South Storage FSS
16011	P/L Storage-Transco-Gainesville
16012	Southern(LNG)-Columbus
16013	Bon Harbor Storage
16014	Grandview Storage
16015	Hickory Storage
16016	Kirkwood Storage
16017	St. Charles Storage
16023	Keystone
16027	Caledonia Storage In VA
16028	Oneok Texas Gas Storage FELMAC
16029	Petal Gas Storage
16030	Worsham Steed Storage

Sub Account	Description
16031	Sequent Leased Storage
16032	Enstor Grama Ridge Stored Gas
16033	Hill-Lake Storage
16035	Southern Natural Gas
16036	Tennessee Gas Pipeline
16037	Trunkline Gas Company
16038	Monroe Gas Storage
16039	Monroe FSS 11702
19100	Retirement of MVG Debt
19105	Retirement Premium onNP Series Q
19107	Retirement Premium onNP Series T
19108	Retirement Premium onNP Series U
19110	Retirement Premium onFMB Series P
19113	Retirement Premium onNP Series J
20000	Accumulated Other Comprehensive Income
20090	Blueflame OCI
20100	OCI CF Hedge Non-Aff
20101	OCI CF Hedge Aff
20102	OCI-Other
20103	OCI-Scotland T lock
20104	OCI-Suntrust T Lock Mar 09
20105	OCI-$400M T Lock June2011
20107	OCI-$350M T Lock Feb-13
20108	OCT 2014 Int rate swaps
20109	JUN 2017 Int rate swaps
20111	MAR 2019 Int rate swaps
20200	Med Term Notes
20223	Debentures 6.75
20231	4.95% Senior Notes due2014
20232	5.95% Senior Notes due2034
20233	Fixed Rate due 2017
20234	8.50% Senior Notes due2019
20235	5.50% Senior Notes due2041
20236	4.15% Senior Notes due2043
20605	N/P-ST Loan
20609	Intercompany Borrowing
20634	CP-Wells Fargo
20635	CP-Wells Fargo Discount
20636	CP- Deutsche Bank
20637	CP- Deutsche Bank Discount
20638	CP- Goldman Sachs
20639	CP- Goldman Sachs Discount
20640	CP- Morgan Stanley
20641	CP- Morgan Stanley Discount
20642	CP- Royal Bank of Scotland
20643	CP- Royal Bank of Scotland Discount
21000	Net Payroll Accrual
21001	Current Liab-A/P Vouchers
21007	Emp Supp Life Ins
21010	Emp Ad&D
21012	Emp ESOP
21016	Emp Credit Union
21018	Emp United Way
21020	Federal PAC
21026	401K Match
21028	Emp 401K Loan
21029	Emp 401k
21032	Empr Esop-Other Exp
21033	Empr Esop
21035	Empr Ltd Ins
21036	Empr Basic Life
21040	Empr Medical/Dental
21043	Emp Medical Prem W/H
21045	Emp Dental Prem W/H
21047	Medical/Dental Clearing
21048	Med/Dental-Other Exp Pymt
21049	PTO Accrual
21050	Accrued Payroll
21052	Vision Plan
21053	Pretax Flex Medical Plan
21054	Pretax Dependent CarePlan
21060	GE FAMG-USP
21061	GE FAMG-SAH
21062	GE FAMG-HP
21063	PT US Able ADD
21067	Fix6
21068	Auto Club
21069	Employee Direct Deposit
21076	OGLM
21078	Emp voluntary deduction
21081	AEH Opt Emp Life
21082	Med AEH Base Plan
21083	Med AEH Buy-Up
21084	AEH Vision Plan
21085	AEH Dental Plan
21086	AEH 401K
21087	AEH 401K Loan
21089	AEH FSA Medical
21092	AEH Pre Tax Colonial
21095	ANB Cash Reclass
21096	AEH 401K Match
21099	Conservation & EnergyEff Program
21100	AEH 401k Safe Harbor

Sub Account	Description
21101	Estimated Gas Cost
21115	Other Payable
21136	Aligne Accounts Payable
21170	Emp GVUL Investment Fund
21178	Health Spending Account
21252	Borrowed Gas
21253	Accrued Gas Liability
21305	Accrued Gas Payable
21306	RSP FACC Empr Payable
23116	Over/Under-Pr Yr
23500	Contract Retain
23501	Customer Contributions
23502	CO Low Income
24603	Other A/P-Def Cr Cl Cur
24607	EY Atmos Audit 10-K ARS Fees
24612	Other A/P-Uncashed Checks
24618	Stocked Item PO Clearing
24619	Non-Stocked Item PO Clearing
24634	EY Interim Reviews 10-Q Fees
24635	Internal Audit KPMG Service Fees
24644	Atmos-Wrong Payee
24646	BFI property insurancetax
25000	Customer Deposits- Active
25001	Customer Deposits-NonCIS
25102	Empr Fica-Accrual
25104	Empr Futa-Accrual
25107	State Unemployment Tax
25113	La Superv & Inspect Tax
25114	State Franchise Tax Accrl
25115	Permit Fees
25116	Gross Receipts Tax
25123	Use Tax
25142	Tx Gas TransportationTax
25144	Severance Tax
25179	OH Commercial ActivityTax
25201	Ad Valorem Tax
26501	Federal Income Tax
26502	Fed Inc Tax-Prior Year
26503	State Income Tax
26504	Federal Tax Interest/Penalties
26505	State Tax Interest/Penalties
26506	Fin 48 Liability
26628	UCG - Mtn 95-1
26631	Int Accr-Deb. 6.75
26647	Int-4.95 % Senior Notes due 2014
26648	Int-5.95 % Senior Notes due 2034
26652	Fixed Rate due 2017
26653	Int-8.50 % Senior Notes due 2019
26654	Int-5.50% Senior Notesdue 2041
26655	Int-4.15% Senior Notesdue 2043
26906	Accrued Bank LC Fees
26908	Int Accr - New ST loan
26916	Commit Fees-Amarillo NB
26918	Commit Fees-Ryl Bk Scotland
26919	Int On Customer Deposits
26922	Int On Non-CIS Deposits
27201	Emp Fica-Accrual
27202	Sales Tax
27204	Emp Fit-Accrual
27205	Emp Sit-Accrual
27206	Emp Local Tax-Accrual
27208	Emp Co Local Tax-Accrual
27209	City Franchise Tax
27210	State Sales Tax
27211	County Sales Tax
27212	City Sales Tax
27213	Texas State & City Sales Tax
27214	KY State Sales Tax
27215	KY Utility School Tax
27217	Iowa Sales Tax
27218	Alabama Sales Tax
27222	Gross Receipts
27223	Consumer Tax
27224	Icc Supp Fee
27233	LA State Sales Tax-Code 1
27235	WKG County-School Taxes
27236	Arkansas State Sales Tax
27238	Georgia State Sales Tax
27239	Indiana State Sales Tax
27240	Illinois State Sales Tax
27242	Mississippi State Sales Tax
27243	Missouri State Sales Tax
27244	North Carolina State Sales Tax
27246	Pennsylvania State Sales Tax
27252	Tennessee Sales Tax Collected
27253	Sales Tax-Tupelo 6 1/4%
27259	Ohio State Sales Tax
27262	Kansas State Sales Tax
27264	Texas Pipeline & Safety Fees
27265	Jefferson Parish Permit Fees
27266	Huntsville Alabama License Tax
27267	Indiana Utility Receipt Tax
27269	State-Gross Production

Sub Account	Description
27270	3rd Party Transport Tax Estimate
27273	KY School Tax
27276	IL Severance Tax
27277	KY Severance Tax
27279	VA State Tax
27307	Performance Plan
27314	Pipeline Refunds
27318	Fas 106/OPEB Accrual
27325	Employee Flexible CompPlan
27339	Inc Tax Pay Future Rates
27341	Cust Adv for Construction
27346	Gas Research Institute
27347	Hedging Open Positions
27349	WM Performance Plan
27351	Customer Billing Accrual
27352	Automated Meter Reading credits
27353	Deferred Billing AR
27354	Leased Gas District Rent
27357	Deposit for future gasflows
27358	CIG(Colorado Interstate Gas Company)Imb
27359	Deferred Franchise Fee
27364	Gas Imbalance Payable
27365	Unbilled Financial Settlement-WMLLC
27368	Def Lease IC-Curr
27371	Amarillo LDC
27381	PSCO Front Range
27382	PSCO Southern
27383	PSCO Western
27384	Texas Gas Imbalance
27386	Misc
27387	Storage Imbalance
27394	El Paso Imbalance
27401	Nymex Swaps-Open Positions
27403	Options-Open Positions
27407	NWPL
27408	Questar
27409	KGS
27410	PEPL
27413	Texas Gas Transmission
27415	Natural Gas Pipeline
27416	Transwestern Pipeline
27417	Reserve for Interim Rates
27703	Other
27706	Fas 106/OPEB
27707	Directors' Def Comp
27709	Fas106-Veba Trust/Admin
27710	Fas 106 - Veba Trust
27712	Deferred Retirement Costs
27713	Dir Retirement Plan Accr
27714	Deferred Revenue-Nonaff
27725	Income Tax Recover Future
27728	FAS 106 Premiums Incurred
27729	FAS 106 Claims Incurred
27730	FAS 106 Premiums W/H
27731	FAS 106 Admin Fees
27736	Durango Sublease Deposit
27737	Accrued Interest on COLI Policies
27742	Def Lease IC - LT
27743	FAS 106/OPEB - MVG
27748	Gross up- CIAC
27749	FAS 106 Retiree Life Insurance Premiums
27751	Medicare Advantage Plan Premiums
27752	LT Fin 48 Liability
27753	McKinney Lease Leveling
27754	Olathe Lease Leveling
27755	Canyon Dr Lease Leveling
27756	Mid-Tex Lease Leveling
27757	Louisville Lease Leveling
27759	Mid-Tex Lincoln LeaseLeveling
27760	Midland Lease Leveling
27761	Austin Lease Leveling
27762	SS Lincoln Lease Leveling
27770	Sugarcube Denver LeaseLeveling
27771	Greeley Lease Leveling-54th st
27772	Bristol Lease Leveling
27774	Franklin Lease Leveling-Riverside 210
27775	Franklin Lease Leveling-Crescent
27777	Mayfield Lease Leveling
27778	Bowling Green Lease Leveling
27779	Owensboro Lease Leveling
27781	Poydras Lease leveling
27783	Rider Revenue Accrual
27785	Columbia Lease Leveling
27786	Meeker Lease Leveling
27787	Tower Lease Leveling
27788	Burnet, TX Lease Leveling
27789	Houston-Granite LeaseLeveling
27790	Franklin Lease Leveling-Riverside 120
27791	LT-Fed Tax Int/Penalties
27792	LT-State Tax Int/Penalties
27908	Virginia SAVE
28001	Deferred Itc - Federal
28101	Inj & Damages-Ins Reserve

Sub Account	Description
28102	Workers' Comp-Ins Reserve
28109	R&D Surcharge
28111	Property Insurance reserve
28201	Accum Defer Fed Income
28204	Federal - Other
28206	Accum Defer State IncTax
29000	Unrealized Gas Cost
29002	MTM-Open Futures Contracts
29003	Asset Management
29005	Bad Debt Gas Cost
29007	Margin Loss Recovery
29011	Bad Debt Recovery
29013	Asset Management-MS Valley Gas
29014	Deferred APT PipelineCost
29015	Dallas Res & Comm BadDebt Gas Cost
29016	Environs Res & Comm Bad Debt Gas Cost
29017	Settled Cities Res & Comm Bad Debt Gas
29020	Settled Cities IndustBad Debt Gas Cost
29021	Deferred Option Premiums
30002	Depr Exp-Natural Gas Prod
30003	Depr Exp-Underground Storage
30004	Depr Exp-TransmissionPlant
30005	Depr Exp-DistributionPlant
30007	Depr Exp-General Plant
30010	Amort-Lease Improvements
30011	Amort Util/Plant Acq Adj
30013	Depreciation-Building
30014	Depreciation-Office furniture
30015	Depreciation-Comm Equip
30021	Customer Contracts - Amort
30023	Amortization of FAS109Regulatory Items
30025	Rate Case Expenses (GUD 10132)
30031	Vehicle Depreciation
30032	Vehicle Depreciation Capitalized
30041	Heavy Equipment Depreciation
30042	Heavy Equipment Depreciation Capitalize
30051	Stores Depreciation
30052	Stores Depreciation Capitalized
30061	Tools & Shop Depreciation
30062	Tools & Shop Depreciation Capitalized
30071	Lab Depreciation
30072	Lab Depreciation Capitalized
30101	Ad Valorem - Accrual
30102	Taxes Property And Other
30103	Occupational Licenses
30104	State Supv & Inspection
30105	Corp/State Franchise Tax
30107	City Franchise
30108	Dot Transmission UserTax
30109	State Gross Receipts
30110	State Gas Transportation
30112	Public Serv Comm Assessment
30118	Penalty - Interest
30119	Cust Deps-By Acct/Div
30120	Commitment Fees-Anb
30121	Commitment Fee- RoyalBank of Scotland
30122	Div-Common Stock
30123	NonCash-PB-Stock Dividend
30128	Int On Debt To Assoc.Co
30129	Int On S/T Loan-Misc
30130	Deferred Interest Infrastructure
30132	1St Mortg Bonds SeriesI
30134	Debentures 6.75 percent
30140	Int On S/T Debt-New STloan
30141	Int On S/T Debt-JP Morgan ST bridge loa
30155	Commitment Fees _ Fortis Capital
30156	Int On deferred director comp
30157	Int on Taxes
30159	Debt expense on Mid-Tex LTD
30160	FMB Early Retirement Premium
30161	6.35% Note Amortization
30163	8.50% Senior Notes disc
30164	Cash equivalent - RSU
30165	CP-Wells Fargo Interest Exp
30166	5.5% Senior Notes disc
30167	4.15% Senior Notes discount
30170	CP- Deutsche Bank IntExp
30171	CP- Goldman Sachs IntExp
30172	CP- Morgan Stanley IntExp
30173	CP- Royal Bank of Scotland Int Exp
30201	Federal Income Taxes
30202	State Income Taxes
30205	FIN48 Federal Tax Expense
30303	Gross Sales - Merchandising
30411	Costs from EDS field
30526	Misc Other Revenue
30543	Other Misc
30554	Retail Ventures Allocation
30601	Int & Div Income-OtherInv
30602	Int & Div Income-TempCash I
30603	Int & Div Income-Non Operation
30604	Int & Div Income-Misc
30606	Misc Non-Operating Income

Sub Account	Description
30607	Incentive Rates Income
30608	Invest Income-Tax Free
30609	Int & Div Inc-Alloc
30611	Misc Operating Income
30612	Int & Div Inc-Interco
30625	CIAC Gross-Up Amort
30702	Education
30703	United Way Agencies
30705	Health
30706	Museums & Arts
30709	Salvation Army
30710	Youth Clubs & Centers
30711	Energy Assistance Program
30713	American Red Cross
30736	Community Welfare
30737	Political Activities
30740	Misc Income Deductions
30743	Entertainment & SportsEvents
30918	UCG - Mtn 95-1
30921	Debentures 6.75 percent
30926	LTD-Leasing
30935	LTD-4.95 % Senior Notes due 2014
30936	LTD-5.95 % Senior Notes due 2034
30937	LTD-Rate Lock
30939	Fixed Rate due 2017
30940	LTD-8.50 % Senior Notes due 2019
30941	LTD-5.50% Sr Notes due2041
30942	LTD-4.15% Sr Notes due2043
31101	Gas Rev-Dist Inc
31108	Gas Rev-Dist Inc. BaseCharges
31113	Sales For Resale
31115	Office Rental
31116	Appliance Rental
31121	Service Revenue
31126	Shop At Home - Sales
31127	Home Protection Revenue
31128	Gas Cost Adjustment Surcharge
31132	Realized Enhancement
31133	Auto Club - Sales
31136	Gas Sales-Nonaff
31137	Gas Sales-Aff
31140	Transport Reimbursed-Nonaff
31141	Transport Reimbursed-Aff
31142	Storage Reimbursed-Nonaff
31143	Storage Reimbursed-Aff
31149	Interest Income
31180	Handbill Est - Unbilled
31181	City franch revenue
31182	State Occup revenue
31183	Surcharge revenue
31195	WNA
31198	Meter Maint & Repair Revenues
31200	GRIP 2009
31201	Forfeited Disc-Dist Plant Inc
31210	GRIP 2010
31211	GRIP 2011
31214	2010 Investment Settlement
31301	Misc Service Revenue
31304	Gas Transport Rev-Distr
31305	Sales For Resale
31306	Intraco Transport Rev
31307	Op Inc&Exp-Prod Extr Ng
31308	Rent From Gas Property
31309	Other Gas Revenues
31312	Monthly Demand
31314	Storage Rent
31318	CAST-GA
31319	HUB Transaction Revenue
31321	Rev-Storing 311 Gas for Others
31324	Parking Transp Rev- 311(A)(2)
31325	LDC Transp - 3rd parties
31326	Industrial Transportation
31332	Trans for Midtex-RateCGS
31333	Electric Generation
31335	Parking TransportationRevenue
31336	Lending TransportationRevenue
31337	Pipeline
31338	Pipeline-311(A)(2)-Texas
31340	Compress Rev-Transp Customers
31341	Other Transport Related Rev
31342	HUB Trans Rev - 311(A)(2)Texas
31343	Rev-Storing Gas of Others
31345	Parking Trans Rev-Affiliate/AEM
31347	Pipeline-311(a)(2)-Texas-Affiliate/AEM
31348	Pipeline-Affiliate/AEM
31350	Rev-Storage Affiliate/AEM
31361	Storage 311(a)2-Affiliate/AEM
31363	Kansas Ad Valorem Surcharge
31364	Easements
31365	Financial
31367	Asset Management-LA
31368	Intercompany transportation revenue
31369	Capacity Utilization

Sub Account	Description
31371	Asset Management-MS
31372	Ind Trans - Regulated
31373	Ind Trans - Other Revenue
31374	Other Gas Revenue - Taxable
31375	Other Gas Revenue - Non-Taxable
31376	Other Revenue-Operating Fee Intra
35103	FP CF Hedge Ineffectiveness Non-Aff
35104	FP CF Hedge Ineffectiveness Aff
35105	Genl Feed Adjustment
35251	Fixed Price Futures
35261	Fixed Price Swaps Non-Aff
35262	Fixed Price Swaps Aff
35311	Storage Inv
35351	Storage Futures
35361	Storage Swaps-NonAff
35362	Storage Swaps-Aff
35375	Realized Gains on Storage
35376	Storage demand fees
35381	Fair Value Hedge Inventory
35582	Transp Rev-Pooling Transfer
35591	Transp-Rev Pooling-Affiliate/AEM
35702	Fixed Fees-Aff
35704	Fixed Fee Options-Affiliate
35801	Basis Swaps-Nonaff
35802	Basis Swaps-Aff
35901	MTM Reserve Overhead-Nonaff
35902	MTM Reserve Overhead-Aff
35922	MTM Reserve NPV-Aff
35931	MTM Reserve Credit-NonAff
35954	MTM storage
40001	Billed to West Tex Div
40002	Billed to CO/KS Div
40003	Billed to LA Div
40004	Billed to Mid St Div
40007	Billed to Nonutilities
40008	Billed to Mid-Tex Div
40009	Billed to MS Div
40010	Billed to Atmos Pipeline Div
40517	Intercompany billing for AEH AEM and AE
41101	Billed from Accounting
41103	Billed from Customer Service Center
41105	Billed from Gas Control
41106	Billed from Govt Affairs
41107	Billed from HR
41108	Billed from HR Other
41109	Billed from IT
41112	Billed from Investor Relations
41113	Billed from Legal
41114	Billed from Corp Secretary
41115	Billed from Planning &Budget
41116	Billed from Rates
41117	Billed from Purchasing
41119	Billed from Treasury
41120	Billed from Risk Mgmt
41121	Billed from ManagementCommittee
41123	Billing for Overhead Capitalized
41124	Billing for Taxes Other and Depr
41126	Billed from Utility Operations Council
41129	Billing for CSC Depr &Taxes Other
41130	Billing for SS Depr &Taxes Other
41131	Billing for CSC O&M
41132	Billing for SS O&M
41134	Billed from BTL SS
41136	Billed from BTL HQ
41137	Billed from BTL State
41138	Billed from RegulatedOps Support

Service Area	Description
000000	Default
001000	Amarillo Transmission
002000	Shared Services General Office
003000	Amarillo City Plant Distribution
003010	Amarillo Distribution
003040	Plainview
003056	Lubbock
003069	Lamesa
003077	Odessa
003110	Bushland
004000	Fritch & Sanford City Plant Distributio
004015	Fritch
004016	Sanford
005000	West Texas City Plant Distribution
005001	Big Spring
005002	Forsan
005003	Coahoma
005006	Pampa
005007	Panhandle
005031	Palisades
005032	Hereford
005033	Friona
005034	Bovina
005035	Dimmitt
005036	Canyon
005037	Happy
005038	Tulia
005039	Kress
005040	Plainview
005041	Hale Center
005042	Petersburg
005043	Floydada
005044	Lockney
005045	Silverton
005046	Quitaque
005047	Turkey
005048	Littlefield
005049	Muleshoe
005050	Sudan
005051	Amherst
005052	Anton
005053	Olton
005054	Earth
005055	Levelland
005056	Lubbock
005057	Abernathy
005058	Shallowater
005059	Idalou
005060	Ralls
005061	Lorenzo
005062	Crosbyton
005063	Slaton
005064	Southland
005065	Post
005066	Wilson
005067	Tahoka
005068	O'Donnell
005069	Lamesa
005070	Brownfield
005071	Ropesville
005072	Meadow
005073	Seagraves
005074	Seminole
005075	Midland
005076	Stanton
005077	Odessa
005078	Whitharral
005079	Wolfforth
005080	New Deal
005081	Springlake
005082	Vega
005083	Hart
005086	Welch
005087	Edmonson
005088	New Home
005089	Smyer
005090	Village of Tanglewood
005091	Nazareth
005092	Wellman
005093	Ransom Canyon
005094	Timbercreek Canyon
005096	Los Ybanez
005097	Opdyke
005098	Buffalo Spring Lake
005114	Dawn
005149	Spade
005171	Lenorah
005201	Claude
006000	Dalhart City Plant Distribution
006020	Dalhart
006021	Channing
006022	Hartley
006032	Hereford

Service Area	Description
007000	TransLa
007700	Lafayette
007701	Mansfield
007702	Natchitoches
007703	Pineville
007704	Winnfield
007705	Monroe
007706	Many
007707	Youngsville
007709	Rayne
007710	Ball
007711	Breaux Bridge
007712	Broussard
007713	Campti
007714	Cankton
007715	Carencro
007716	Clarks
007717	Converse
007718	Coushatta
007719	Dry Prong
007720	Edgefield
007721	Fisher
007722	Florien
007723	Franklin
007724	Georgetown
007725	Grayson
007726	Henderson
007727	Baldwin
007728	Duson
007729	Olla
007730	Pleasant Hill
007731	Pollock
007732	Richwood
007733	Robeline
007734	Scott
007735	South Mansfield
007736	Stanley
007737	Tullos
007738	Urania
007739	Zwolle
007740	Nebo
007741	Standard
007742	Belle Rose
007743	Gray
007744	Houma
007745	Labadieville
007746	Paincourtville
007747	Plattenville
007748	Schriever
007749	White Castle
007750	Amelia
007751	Bunkie
007752	Catahoula
007753	Cecilia
007754	Centerfield
007755	Charenton
007756	Colfax
007757	Columbia
007758	Crowley
007759	Eunice
007760	Ft Jesup
007761	Greenwood
007762	Jeanrette
007763	Kolin
007764	Lecompte
007765	Logansport
007766	New Iberia
007767	Patterson
007768	St Landry
007769	Ville Platte
007770	Washington
007771	West Monroe
007772	Thibodaux/Lafourche
007773	Napoleonville
007774	Church Point
007775	Oxford
007776	Pelican
007777	Sterlington
007778	Opelousas
007779	St Amant
007780	Darrow
007781	Baldwin
007782	Powhattan
007783	Branch
007784	Church Point
007785	Duson
007786	Joyce
007787	Kaplan
007788	Maurice
007789	Opelousas
007790	Winn Parish Prison
007791	Bayou Correctional Facility
007792	Universities & VA

Service Area	Description
007793	Port Barre
007794	Rayne
007795	St Landry
007796	Sunset
007797	Basile
007799	Transla BU A&G
008000	West Texas Div-West Texas Rural Irrigat
008001	West Texas Div Irrigation-Big Spring IR
008002	West Texas Div Irrigation-Forsan
008003	West Texas Div Irrigation-Coahoma
008006	West Texas Div Irrigation-Pampa IRR
008007	West Texas Div Irrigation-Panhandle
008009	West Texas Div Irrigation-Tex Div Offic
008010	West Texas Div Irrigation-Amarillo Dist
008015	West Texas Div Irrigation-Fritch
008016	West Texas Div Irrigation-Sanford
008020	West Texas Div Irrigation-Dalhart
008021	West Texas Div Irrigation-Channing
008022	West Texas Div Irrigation-Hartley
008031	West Texas Div Irrigation-Palisades
008032	West Texas Div Irrigation-Hereford IRR
008033	West Texas Div Irrigation-Friona IRR
008034	West Texas Div Irrigation-Bovina
008035	West Texas Div Irrigation-Dimmitt
008036	West Texas Div Irrigation-Canyon IRR
008037	West Texas Div Irrigation-Happy
008038	West Texas Div Irrigation-Tulia
008039	West Texas Div Irrigation-Kress
008040	West Texas Div Irrigation-Plainview IRR
008041	West Texas Div Irrigation-Hale Center
008042	West Texas Div Irrigation-Petersburg
008043	West Texas Div Irrigation-Floydada
008044	West Texas Div Irrigation-Lockney
008045	West Texas Div Irrigation-Silverton
008046	West Texas Div Irrigation-Quitaque
008047	West Texas Div Irrigation-Turkey
008048	West Texas Div Irrigation-Littlefield I
008049	West Texas Div Irrigation-Muleshoe
008050	West Texas Div Irrigation-Sudan
008051	West Texas Div Irrigation-Amherst
008052	West Texas Div Irrigation-Anton
008053	West Texas Div Irrigation-Olton IRR
008054	West Texas Div Irrigation-Earth IRR
008055	West Texas Div Irrigation-Levelland
008056	West Texas Div Irrigation-Lubbock IRR
008057	West Texas Div Irrigation-Abernathy
008058	West Texas Div Irrigation-Shallowater
008059	West Texas Div Irrigation-Idalou
008060	West Texas Div Irrigation-Ralls
008061	West Texas Div Irrigation-Lorenzo
008062	West Texas Div Irrigation-Crosbyton
008063	West Texas Div Irrigation-Slaton
008064	West Texas Div Irrigation-Ropesville-So
008065	West Texas Div Irrigation-Post
008066	West Texas Div Irrigation-Wilson
008067	West Texas Div Irrigation-Tahoka
008068	West Texas Div Irrigation-O'Donnell
008069	West Texas Div Irrigation-Lamesa
008070	West Texas Div Irrigation-Brownfield IR
008071	West Texas Div Irrigation-Ropesville
008072	West Texas Div Irrigation-Meadow
008073	West Texas Div Irrigation-Seagraves
008074	West Texas Div Irrigation-Seminole
008075	West Texas Div Irrigation-Midland
008076	West Texas Div Irrigation-Stanton
008077	West Texas Div Irrigation-Odessa IRR
008078	West Texas Div Irrigation-Whitharral
008079	West Texas Div Irrigation-Wolfforth
008080	West Texas Div Irrigation-New Deal
008081	West Texas Div Irrigation-Springlake
008082	West Texas Div Irrigation-Vega
008083	West Texas Div Irrigation-Hart
008086	West Texas Div Irrigation-Welch
008087	West Texas Div Irrigation-Edmonson
008088	West Texas Div Irrigation-New Home
008089	West Texas Div Irrigation-Smyer
008090	West Texas Div Irrigation-Village of Ta
008091	West Texas Div Irrigation-Nazareth
008092	West Texas Div Irrigation-Wellman
008093	West Texas Div Irrigation-Ransom Canyon
008094	West Texas Div Irrigation-Timbercreek C
008096	West Texas Div Irrigation-Los Ybanez
008097	West Texas Div Irrigation-Opdyke
008098	West Texas Div Irrigation-Buffalo Sprin
008110	Bushland
008140	Farwell
009000	KY
009001	Owensboro-Underground Storage
009002	Hickory-Underground Storage
009003	Kirkwood-Underground Storage
009004	Judge Chapel-Underground Storage
009005	Bon Harbor-Underground Storage
009006	Commonwealth-Underground Storage

Service Area	Description
009007	St Charles-Underground Storage
009008	Phelps Dodge-Underground Storage
009500	Owensboro
009501	Beaver Dam
009502	Calhoun
009503	Cloverport
009504	Fordsville
009505	Hardinsburg
009506	Hartford
009507	Hawesville
009508	Whitesville
009509	Lewisport
009515	Madisonville
009516	Earlington
009517	Hanson
009518	Morton's Gap
009519	Nortonville
009520	St Charles
009521	Sebree
009522	Dixon
009523	Slaughters
009524	South Henderson
009527	Wkg Measurement
009530	Princeton
009531	Cadiz
009532	Dawson Springs
009533	Eddyville
009534	Marion
009535	Fredonia
009537	Hopkinsville
009538	Crofton
009539	Livermore KY
009540	Greenville
009541	Central City
009542	Bremen
009543	Powderly
009544	Sacramento
009545	Rural Owensboro
009546	Rural Madisonville
009547	Rural Paducah
009548	Rural Bowling Green
009549	Rural Danville
009550	Paducah
009551	Calvert City
009552	Gilbertsville
009553	Grand Rivers
009555	Mayfield
009556	Water Valley
009557	Wingo
009558	Symsonia
009560	Bowling Green
009562	Russellville
009563	Adairville
009564	Elkton
009565	Franklin
009566	Auburn
009567	Woodburn
009570	Glasgow
009571	Cave City
009572	Hiseville
009573	Horse Cave
009574	Munfordville
009575	Oakland
009576	Park City
009577	Smith's Grove
009580	Danville
009581	Hustonville/Moreland
009582	Junction City
009583	Lancaster
009584	Perryville
009585	Stanford
009587	Lebanon
009588	Springfield
009590	Harrodsburg
009591	Burgin
009592	Campbellsville
009593	Greensburg
009595	Shelbyville
009596	Lawrenceburg
009599	Wkg BU A&G
010000	West Texas Div
010001	Big Spring
010006	Pampa
010007	Panhandle
010009	West Texas Div Office
010010	Amarillo
010015	Fritch
010020	Dalhart
010021	Channing
010032	Hereford
010033	Friona
010035	Dimmitt
010036	Canyon

Service Area	Description
010037	Happy
010038	Tulia
010040	Plainview
010043	Floydada
010045	Silverton
010046	Quitaque
010048	Littlefield
010049	Muleshoe
010055	Levelland
010056	Lubbock
010060	Ralls
010061	Lorenzo
010063	Slaton
010065	Post
010067	Tahoka
010069	Lamesa
010070	Brownfield
010074	Seminole
010075	Midland
010076	Stanton
010077	Odessa
010081	Springlake
010099	West Texas Div BU A&G
010102	Plant In Service
012000	Customer Support
013000	Amarillo Rural Distribution
013010	Amarillo
013110	Bushland
014000	Non-Regulated Industrial
014001	Big Spring
014007	Panhandle
014010	Amarillo
014021	Industrial-WT-Rural
014032	Hereford
014033	Friona
014034	Bovina
014035	Dimmitt
014036	Canyon
014038	Tulia
014040	Plainview
014043	Floydada
014044	Lockney
014046	Quitaque
014048	Littlefield
014049	Muleshoe
014052	Anton
014053	Olton
014054	Earth
014055	Levelland
014056	Lubbock
014057	Abernathy
014062	Crosbyton
014063	Slaton
014066	Wilson
014068	O'Donnell
014069	Lamesa
014070	Brownfield
014072	Meadow
014073	Seagraves
014074	Seminole
014075	Midland
014077	Odessa
014082	Vega
014087	Edmonson
014089	Smyer
014092	Wellman
015000	Regulated Industrial
015001	Big Spring
015003	Industrial-AM City Gate
015005	Industrial-WT-City Gate
015010	Amarillo
015016	WT Div LVS customers in Lubbock
015020	Dalhart
015021	Industrial-WT-Rural
015032	Hereford
015033	Friona
015036	Canyon
015040	Plainview
015048	Littlefield
015055	Levelland
015056	Lubbock
015058	Shallowater
015069	Lamesa
015070	Brownfield
015073	Seagraves
015074	Seminole
015075	Midland
015077	Odessa
015079	Wolfforth
015086	Welch
016000	Lubbock City Plant
016056	Lubbock City Plant
017000	Dalhart Rural Distribution

Service Area	Description
017020	Dalhart
018000	Dalhart Rural Irrigation
018020	Dalhart
018022	Hartley
018032	Hereford
019000	West Texas Div- Triangle Pipeline
019007	Panhandle
019010	Amarillo
019020	Triangle 020
019032	Hereford
019033	Friona
019034	Bovina
019035	Dimmitt
019036	Canyon
019038	Tulia
019040	Plainview
019043	Floydada
019044	Lockney
019046	Quitaque
019048	Littlefield
019049	Muleshoe
019050	Sudan
019052	Anton
019053	Olton
019054	Earth
019055	Levelland
019056	Lubbock
019057	Abernathy
019059	Idalou
019060	Ralls
019062	Crosbyton
019063	Slaton
019065	Post
019069	Lamesa
019070	Brownfield
019071	Ropesville
019072	Meadow
019073	Seagraves
019074	Seminole
019079	Wolfforth
019081	Springlake
019082	Vega
019083	Hart
019086	Welch
019087	Edmonson
019091	Nazareth
019092	Wellman
019149	Spade
020000	West Texas Lubbock Environs
020056	Lubbock outside city limits
020601	Alvarado Other_Oc_TP
021000	West Texas Rural Distribution
021001	Big Spring
021002	Forsan
021003	Coahoma
021006	Pampa
021007	Panhanle
021010	Amarillo
021020	West Texas - Dalhart
021031	Palisades
021032	Hereford
021033	Friona
021034	Bovina
021035	Dimmitt
021036	Canyon
021037	Happy
021038	Tulia
021039	Kress
021040	Plainview
021041	Hale Center
021042	Petersburg
021043	Floydada
021044	Lockney
021045	Silverton
021046	Quitaque
021047	Turkey
021048	Littlefield
021049	Muleshoe
021050	Sudan-SU
021051	Amherst
021052	Anton
021053	Olton
021054	Earth
021055	Levelland
021056	Lubbock
021057	Abernathy
021058	Shallowater
021059	Idalou
021060	Ralls
021061	Lorenzo
021062	Crosbyton
021063	Slaton
021064	Southland

Service Area	Description
021065	Post
021066	Wilson
021067	Tahoka
021068	O'Donnell
021069	Lamesa
021070	Brownfield
021071	Ropesville
021073	Seagraves
021074	Seminole
021075	Midland
021076	Stanton
021077	Odessa
021078	Whitharral
021079	Wolfforth
021081	Springlake-SP
021082	Vega
021083	Hart
021086	Welch
021087	Edmonson
021089	Smyers
021091	Nazareth
021092	Wellman
021096	Los Ybanez
021097	Opdyke
021110	Bushland
021113	Cotton Center
021114	Dawn
021125	Umbarger
021140	Farwell
021149	Spade
021171	Lenorah
021201	Claude
022000	West Texas Div Meter Shop
022436	West Texas Div Measurement Center
030000	COKS/Denver Company Office
030366	Yates Center
030367	Coffeyville
030368	Independence
030369	Johnson County-Olathe
030800	Denver
030810	Greeley
030896	BU Overhead-GGC
030899	BU Overhead-Colorado
031000	Colorado ADM
031800	Cbd-Escrow Account
031810	Greeley
031811	Ault
031818	Kersey
031821	Platteville
031845	Graig
031846	Meeker
031855	Steamboat Springs
031858	Steamboat Springs URA
031860	Canon City
031861	Florence, Co
031873	Salida
031880	Gunnison
031881	Crested Butte
031882	Mount Crested Butte
031899	Colorado BU A&G
031901	Lamar
031909	Holly
031924	Springfield
031935	Durango
031938	Cortez
031941	Dove Creek
033000	Northeast Colorado
033264	Rosedale
033374	Danville
033810	Greeley
033811	Ault
033812	Eaton
033813	Evans
033814	Garden City
033815	Gilcrest
033816	Hudson
033817	Keenesburg
033818	Kersey
033819	LaSalle
033820	Lucerne
033821	Platteville
033823	Pierce
033824	Prospect Valley
033825	Roggen
033826	Nunn
033827	Outside Ault
033828	Outside Eaton
033831	Outside Gilcrest
033832	Outside Greeley
033838	Outside Platteville
033843	Windsor
033846	Meeker
033847	Hayden

Service Area	Description
033855	Steamboat Springs
033860	Canon City
033861	Florence
033880	Gunnison
033901	Lamar
033953	Windsor
033955	Milliken CO
033956	Fort Lupton-CO
034000	Northwest & Central Colorado
034266	Parlin
034270	Almont
034845	Craig
034846	Meeker
034847	Hayden
034849	Outside Hayden
034850	Outside Graig
034855	Steamboat Springs
034856	Milner
034857	Outside Steamboat Springs
034860	Canon City
034861	Florence
034873	Salida
034874	Poncha Springs
034875	Nathrop
034877	Outside Poncha
034880	Gunnison
034881	Crested Butte
034882	Mt Crested Butte
034883	Outside Crested Butte
034885	Outside Gunnison-Gunnison County
034935	Durango
034951	Buena Vista
034954	Hamilton
035000	Southeast Colorado
035265	Lincoln Park
035810	Greeley
035860	Canon City
035861	Florence
035862	Portland
035863	Penrose
035864	Williamsburg
035865	Rockvale
035866	Outside Canon City
035867	Brookside
035901	Lamar
035902	Hasty
035903	McClave
035904	Brandon
035905	Eads
035906	Bristol
035907	Granada
035908	Hartman
035909	Holly
035910	Kornman
035911	Wiley
035921	Outside Lamar
035922	Outside Wiley
035924	Springfield
035925	Pritchett
035926	Two Buttes
035927	Vilas
035928	Walsh
035930	Outside Springfield
036000	Southwest Colorado
036935	Durango
036936	Outside Durango
036938	Cortez
036939	Dolores
036940	Mancos
036941	Dove Creek
036942	Cahone
036943	Egnar
036944	Outside Cortez
036950	Hesperus
040000	CNG
040006	Cng Pampa
040010	Cng Amarillo
040036	Cng Canyon
040055	Cng Levelland
040056	Cng Lubbock
040075	Cng Midland
040077	Cng Odessa
041000	Use 034000 Buena Vista Division
047000	Cng Trans La Cng
050000	Egasco
050001	Egasco-Big Spring
050002	Egasco-Forsan
050003	Egasco-Coahoma
050006	Egasco-Pampa
050007	Egasco-Panhandle
050009	Egasco-West Texas Div Office
050010	Egasco-Amarillo Distribution
050015	Egasco-Fritch

Service Area	Description
050016	Egasco-Sanford
050020	Egasco-Dalhart
050021	Egasco-Channing
050022	Egasco-Hartley
050031	Egasco-Palisades
050032	Egasco-Hereford
050033	Egasco-Friona
050034	Egasco-Bovina
050035	Egasco-Dimmitt
050036	Egasco-Canyon
050037	Egasco-Happy
050038	Egasco-Tulia
050039	Egasco-Kress
050040	Egasco-Plainview
050041	Egasco-Hale Center
050042	Egasco-Petersburg
050043	Egasco-Floydada
050044	Egasco-Lockney
050045	Egasco-Silverton
050046	Egasco-Quitaque
050047	Egasco-Turkey
050048	Egasco-Littlefield
050049	Egasco-Muleshoe
050050	Egasco-Sudan
050051	Egasco-Amherst
050052	Egasco-Anton
050053	Egasco-Olton
050054	Egasco-Earth
050055	Egasco-Levelland
050056	Egasco-Lubbock
050057	Egasco-Abernathy
050058	Egasco-Shallowater
050059	Egasco-Idalou
050060	Egasco-Ralls
050061	Egasco-Lorenzo
050062	Egasco-Crosbyton
050063	Egasco-Slaton
050064	Egasco-Southland
050065	Egasco-Post
050066	Egasco-Wilson
050067	Egasco-Tahoka
050068	Egasco-O'Donnell
050069	Egasco-Lamesa
050070	Egasco-Brownfield
050071	Egasco-Ropesville
050072	Egasco-Meadow
050073	Egasco-Seagraves
050074	Egasco-Seminole
050075	Egasco-Midland
050076	Egasco-Stanton
050077	Egasco-Odessa
050078	Egasco-Whitharral
050079	Egasco-Wolfforth
050080	Egasco-New Deal
050081	Egasco-Springlake
050082	Egasco-Vega
050083	Egasco-Hart
050086	Egasco-Welch
050087	Egasco-Edmonson
050088	Egasco-New Home
050089	Egasco-Smyer
050090	Egasco-Village of Tanglewood
050091	Egasco-Nazareth
050092	Egasco-Wellman
050093	Egasco-Ransom Canyon
050094	Egasco-Timbercreek Canyon
050096	Egasco-Los Ybanez
050097	Egasco-Opdyke
050098	Egasco-Buffalo Spring Lake
051000	Enertrust Inc
051036	Enermart-Canyon
051055	Enermart-Levelland
051056	Enermart-Lubbock
051069	Enermart-Lamesa
052000	TLGP
052700	TLGP-Lafayette
052701	TLGP-Mansfield
052702	TLGP-Natchitoches
052703	TLGP-Pineville
052704	TLGP-Winnfield
052705	TLGP-Monroe
052706	Many-TLGP
052711	TLGP-Breaux Bridge
052712	Broussard-TLGP
052718	TLGP-Coushatta
052726	Henderson-TLGP
052729	Olla-TLGP
052736	Stanley-TLGP
052739	Zwolle-TLGP
052744	Houma-TLGP
052745	Labadieville-TLGP
052750	TLGP-Amelia
052755	TLGP-Charenton

Service Area	Description
052762	TLGP-Jeanrette
052764	Lecompte-TLGP
052766	TLGP-New Iberia
052767	Patterson
053000	AEP
054000	Enermart Energy Services Trust
054001	Enermart-Big Spring
054002	Enermart-Forsan
054003	Enermart-Coahoma
054006	Enermart-Pampa
054007	Enermart-Panhandle
054009	Enermart-West Texas Div Office
054010	Enermart-Amarillo Distribution
054015	Enermart-Fritch
054016	Enermart-Sanford
054020	Enermart-Dalhart
054021	Enermart-Channing
054022	Enermart-Hartley
054031	Enermart-Palisades
054032	Hereford
054033	Enermart-Friona
054034	Enermart-Bovina
054035	Enermart-Dimmitt
054036	Enermart-Canyon
054037	Enermart-Happy
054038	Enermart-Tulia
054039	Enermart-Kress
054040	Plainview
054041	Enermart-Hale Center
054042	Enermart-Petersburg
054043	Enermart-Floydada
054044	Enermart-Lockney
054045	Enermart-Silverton
054046	Enermart-Quitaque
054047	Enermart-Turkey
054048	Enermart-Littlefield
054049	Enermart-Muleshoe
054050	Enermart-Sudan
054051	Enermart-Amherst
054052	Enermart-Anton
054053	Enermart-Olton
054054	Enermart-Earth
054055	Enermart-Levelland
054056	Enermart-Lubbock
054057	Enermart-Abernathy
054058	Shallowater-Enermart
054059	Enermart-Idalou
054060	Enermart-Ralls
054061	Enermart-Lorenzo
054062	Enermart-Crosbyton
054063	Enermart-Slaton
054064	Enermart-RopesvilleEnermart-Southland
054065	Enermart-Post
054066	Enermart-Wilson
054067	Enermart-Tahoka
054068	Enermart-O'Donnell
054069	Enermart-Lamesa
054070	Brownfield
054071	Enermart-Ropesville
054072	Enermart-Meadow
054073	Enermart-Seagraves
054074	Enermart-Seminole
054075	Enermart-Midland
054076	Enermart-Stanton
054077	Enermart-Odessa
054078	Enermart-Whitharral
054079	Enermart-Wolfforth
054080	Enermart-New Deal
054081	Enermart-Springlake
054082	Enermart-Vega
054083	Enermart-Hart
054086	Enermart-Welch
054087	Enermart-Edmonson
054088	Enermart-New Home
054089	Enermart-Smyer
054090	Enermart-Village of Tanglewood
054091	Enermart-Nazareth
054092	Enermart-Wellman
054093	Enermart-Ransom Canyon
054094	Enermart-Timbercreek Canyon
054096	Enermart-Los Ybanez
054097	Enermart-Opdyke
054098	Enermart-Buffalo Spring Lake
055000	Corporate-AES
055001	Retail-AES
055002	Wholesale-AES
055106	AES - Colorado
055110	AES - Georgia
055113	AES - Illinois
055115	AES - Iowa
055116	AES - Kansas
055117	AES - Kentucky
055118	AES - Louisiana

Service Area	Description
055124	AES - Mississippi
055125	AES - Missouri
055133	AES - North Carolina
055142	AES - Tennessee
055143	AES - Texas
055146	AES - Virginia
056000	TLIG-LGSI
056600	Kilbourne
056601	Bonita
056602	Oak Grove
056603	Bastrop
056604	Lake Providence
056605	Pioneer
056606	Forest
056607	Lisbon
056608	Collinston
056609	Mer Rouge
056610	Oak Ridge
056611	Epps
056612	Rayville
056613	Tallulah
056614	Mound
056615	Delhi
056616	Richmond
056617	Bryceland
056618	Eros
056619	Quitman
056620	Bienville
056621	Hodge
056622	North Hodge
056623	East Hodge
056624	Delta
056625	Mangham
056626	Baskin
056627	Jonesboro
056628	Castor
056629	Hall Summit
056630	Winnsboro
056631	Goldonna
056632	Dodson
056633	Calvin
056634	Gilbert
056635	Wisner
056636	Keatchie
056637	Longstreet
056638	Grand Cane
056639	Ferriday
056640	Ridgecrest
056641	Alto
056642	Archibald
056643	Avondale
056644	Beekman
056645	Cadeville
056646	Calhoun
056647	Camp Joy
056648	Cartwright
056649	Chase
056650	Cheniere
056651	Crew Lake
056652	Crowville
056653	Darnell
056654	Dehlco
056655	Doyline
056656	Dubberly
056658	Feazel-Hwy 15
056659	Floyd
056660	Folwer
056661	Girard
056662	Gloster
056663	Haile
056664	Haughton
056665	Hico
056666	Holly Ridge
056667	Horace Smith System
056668	Hughes Chapel
056669	Hunter Heights
056670	James Smith
056671	James Wade
056672	Jones
056673	Lake Bistinea
056674	Lake Bistineau
056675	Mitchiner
056676	Nelson Bend
056677	Ouachita City
056678	Preeyville
056679	Ringgold
056680	Rocky Branch
056681	Saint Helena
056682	Spencer
056683	Start
056684	Swartz
056685	Taylortoun
056686	Tendell

Service Area	Description
056687	Thomastown
056688	Transvalnia
056689	Vixen
056690	Warden
056691	Waverly
056692	West Sterlington
056693	Weston
056705	Monroe
056706	Many
056713	Campti
056742	Belle Rose
056744	Houma
056749	White Castle
056771	West Monroe
056773	Napoleanville
056777	Sterlington
056794	Wilman
056795	Wyatt
056800	Roseland
056801	Independence
056802	Folsom
056803	Tickfaw
056804	Amite
056805	Covington
056806	Albany
056807	Baton Rouge
056808	Pochatoula
056809	Mandeville
056810	Gonzales
056811	Springfield
056812	Sorrento
056813	Gramercy
056814	Kenner
056815	Lutcher
056816	Westwego
056817	Harahan
056818	Gretna
056819	Slidell
056820	Lafitte
056821	Abita Springs
056822	Alluvial City
056823	Almedia
056824	Ama
056825	Ama-Luling
056826	Arabi
056827	Augusta
056828	Baptist
056829	Bayou Gouche
056830	Bell Chasse
056831	Boothville
056832	Bourg
056833	Boutte
056834	Boutte-Luling
056835	Braithwaite
056836	Bridge City
056837	Bridgedale
056838	Bucktown
056839	Buras
056840	Burly St Martin
056841	Burnside
056842	Caenarvon
056843	Carville
056844	Cedar Grove
056845	Chalmette
056846	D'Arbonne
056847	Davant
056848	Delacroix
056849	Denham Springs
056850	Des Allemands
056851	Destrehan
056852	Duplesis
056853	Edgard
056854	Empire
056855	Florissant
056856	Gallion
056857	Garyville
056858	Geismar
056859	Gloria
056860	Hahnville
056861	Hammond
056862	Harvey
056863	Holden
056864	Hopedale
056865	Jesuit Bend
056866	Keyston
056867	Killona
056868	Lacombe
056869	Laplace
056870	Loranger
056871	Lucy
056872	Luling
056873	Marrero
056874	Merauz

Service Area	Description
056875	Merairie
056876	Modeste
056877	Montegute
056878	Montz
056879	Mt Airy
056880	Naomi
056881	Natalbany
056882	New sarpy
056883	Norco
056884	Oakville
056885	Ollie
056886	Paradis
056887	Paulina
056888	Phoenix
056889	Point A La Hache
056890	Port sulphur
056891	Poydras
056892	Prairieville
056893	Reggio
056894	Reserve
056895	Robert
056896	Saint Bernard
056897	Saint Clair
056898	Saint Grabiel
056899	Saint Mary
056900	Saint Rose
056901	Southport
056902	Toca
056903	Venice
056904	Verdunville
056905	Verrett
056906	Violet
056907	Waggaman
056908	Walker
056909	Wallace
056910	Whitehall
056911	Yscloskey
056912	Jefferson
057000	TLGP-LGSN
058000	TLGP-Pine Pipeline JV
059000	TLIG
059608	TLIG-Haynesville
059700	TLIG-Lafayette
059701	TLIG-Mansfield
059702	TLIG-Natchitoches
059703	TLIG-Pineville
059704	TLIG-Winnfield
059705	TLIG-Monroe
059706	Many-TLIG
059711	TLIG-Breaux Bridge
059712	Broussard-TLIG
059715	TLIG-Carencro
059718	TLIG-Coushatta
059722	TLIG-Florien
059723	TLIG-Franklin
059726	Henderson-TLIG
059729	Olla-TLIG
059736	Stanley-TLIG
059737	Tullos
059739	Zwolle-TLIG
059742	Belle Rose-TLIG
059744	Houma-TLIG
059745	Labadieville-TLIG
059750	TLIG-Amelia
059755	TLIG-Charenton
059762	TLIG-Jeanrette
059764	Lecompte-TLIG
059765	Logansport
059766	TLIG-New Iberia
059767	Patterson
059772	Thibodaux
059773	Napoleonville
060000	TLGP-Sport Pipeline
077000	AE Louisiana - LGS
077600	Kilbourne
077601	Bonita
077602	Oak Grove
077603	Bastrop
077604	Lake Providence
077605	Pioneer
077606	Forest
077607	Lisbon
077608	Collinston
077609	Mer Rouge
077610	Oak Ridge
077611	Epps
077612	Rayville
077613	Tallulah
077614	Mound
077615	Delhi
077616	Richmond
077617	Bryceland
077618	Eros

Service Area	Description
077619	Quitman
077620	Bienville
077621	Hodge
077622	North Hodge
077623	East Hodge
077624	Delta
077625	Mangham
077626	Baskin
077627	Jonesboro
077628	Castor
077629	Hall Summit
077630	Winnsboro
077631	Goldonna
077632	Dodson
077633	Calvin
077634	Gilbert
077635	Wisner
077636	Keatchie
077637	Longstreet
077638	Grand Cane
077639	Ferriday
077640	Ridgecrest
077641	Alto
077642	Archibald
077643	Avondale
077644	Beekman
077645	Cadeville
077646	Calhoun
077647	Camp Joy
077648	Cartwright
077649	Chase
077650	Chenlere
077651	Crew Lake
077652	Crowville
077653	Darnell
077654	Dehico
077655	Doyline
077656	Dubberly
077657	Elm Grove
077658	Feazel-Hwy 15
077659	Floyd
077660	Folwer
077661	Girard
077662	Gloster
077663	Haile
077664	Haughton
077665	Hico
077666	Holly Ridge
077667	Horace Smith System
077668	Hughes Chapel
077669	Hunter Heights
077670	James Smith
077671	James Wade
077672	Jones
077673	Lake Bistinea
077674	Lake Bistineau
077675	Mitchiner
077676	Nelson Bend
077677	Ouachita City
077678	Perryville
077679	Ringgold
077680	Rocky Branch
077681	Saint Helena
077682	Spencer
077683	Start
077684	Swartz
077685	Taylortoun
077686	Tendell
077687	Thomastown
077688	Transylvania
077689	Vixen
077690	Warden
077691	Waverly
077692	West Sterlington
077693	Weston
077694	Wilman
077695	Wyatt
077696	Mandeville
077697	Vidalia
077698	Downsville
077700	Lafayette Service
077702	Natchitoches-LGS
077703	Rapides-LGS
077705	Monroe
077706	Many
077713	Campti
077742	Belle Rose
077744	Houma
077749	White Castle
077771	West Monroe
077773	Napoleonville
077777	Sterlington
077779	St Amant-LGS

Service Area	Description
077780	Darrow-LGS
077800	Roseland
077801	Independence
077802	Folsom
077803	Tickfaw
077804	Amite
077805	Covington
077806	Albany
077807	Baton Rouge
077808	Ponchatoula
077809	Mandeville
077810	Gonzales
077811	Springfield
077812	Sorrento
077813	Gramercy
077814	Kenner
077815	Lutcher
077816	Westwego
077817	Harahan
077818	Gretna
077819	Slidell
077820	Lafitte
077821	Abita Springs
077822	Alluvial City
077823	Almedia
077824	Ama
077825	Ama-Luling
077826	Arabi
077827	Augusta
077828	Baptist
077829	Bayou Gouche
077830	Belle Chasse
077831	Boothville
077832	Bourg
077833	Boutte
077834	Boutte-Luling
077835	Braithwaite
077836	Bridge City
077837	Bridgedale
077838	Bucktown
077839	Buras
077840	Burly St Martin
077841	Burnside
077842	Caenarvon
077843	Carville
077844	Cedar Grove
077845	Chalmette
077846	D'Arbonne
077847	Davant
077848	Delacroix
077849	Denham Springs
077850	Des Allemands
077851	Destrehan
077852	Duplesis
077853	Edgard
077854	Empire
077855	Florissant
077856	Gallion
077857	Garyville
077858	Geismar
077859	Gloria
077860	Hahnville
077861	Hammond
077862	Harvey
077863	Holden
077864	Hopedale
077865	Jesuit Bend
077866	Keyston
077867	Killona
077868	Lacombe
077869	Laplace
077870	Loranger
077871	Lucy
077872	Luling
077873	Marrero
077874	Meraux
077875	Metairie
077876	Modeste
077877	Montegut
077878	Montz
077879	Mt Airy
077880	Naomi
077881	Natalbany
077882	New Sarpy
077883	Norco
077884	Oakville
077885	Ollie
077886	Paradis
077887	Paulina
077888	Phoenix
077889	Point A La Hache
077890	Port Sulphur
077891	Poydras

Service Area	Description
077892	Prairieville
077893	Reggio
077894	Reserve
077895	Robert
077896	Saint Bernard
077897	Saint Clair
077898	Saint Grabiel
077899	Saint Mary
077900	Saint Rose
077901	Southport
077902	Toca
077903	Venice
077904	Verdunville
077905	Verrett
077906	Violet
077907	Waggaman
077908	Walker
077909	Wallace
077910	Whitehall
077911	Yscloskey
081000	GGC-Kansas
081250	Bonner Springs-Wyandotte
081251	Bonner Springs
081252	Kansas City
081253	Edwardsville
081254	Eudora
081255	Lawrence
081256	De Soto
081257	Wilder
081258	Clearview City
081259	Shawnee - R
081260	Havana
081261	Lenexa
081262	Olathe
081263	Basehor
081264	Delaware Twp
081265	Lincoln Park
081266	Wakarusa Twp
081267	Lake of the Forest
081268	Mapleton
081269	Lexington Township
081270	Sherman Township
081271	Fairmont Township
081273	Pleasanton
081274	Mound City
081275	Prescott
081276	Fulton
081277	Redfield
081278	Fort Scott
081279	Fairmont Township
081280	Bucyrus
081281	Sheridan Township
081282	Freedom Twp
081283	Marmation Twp
081284	Osage Twp
081285	Scott Township
081286	Mill Creek Township
081300	Herington
081301	Delavan
081302	Lost Springs
081304	Township #7
081315	Leawood
081330	Council Grove
081331	Council Grove 2
081332	White City
081334	Cottonwood Falls
081335	Strong City
081345	Marion
081346	Hillsboro
081347	Lincolnville
081348	Marion Lake
081349	Peabody
081350	Tampa
081351	Pilsen
081352	Aulne
081353	Ramona
081354	Florence
081356	Clear Creek Township
081357	Altoona
081358	Stark
081363	Neodesha
081364	Gardner
081365	Wyandotte
081366	Yates Center
081367	Coffeyville
081368	Independence
081369	Johnson County-Olathe
081370	Kansas City
081371	Edwardsville
081372	Lenexa
081373	Olathe
081374	Bartlett
081375	Caney

Service Area	Description
081376	Chetopa
081377	Cedar Vale
081378	Dearing
081379	Edna
081380	Fredonia
081381	Galesburg
081382	Linwood
081383	Longton
081384	Mound Valley
081385	Niotaze
081386	Overland Park
081387	Peru
081388	Sedan
081389	Spring Hill
081390	Batchelor Township
081391	Tyro
081392	McCune
081455	Johnson
081456	Manter
081457	Big Bow Township
081458	Manter Township
081459	Stanton Township
081460	Richfield Township
081461	Westola Township
081465	Ulysses
081466	Hickok
081467	Sherman Township
081468	Sullivan Township
081469	Lincoln Township
081470	Harmony Township
081475	Syracuse
081476	Kendall
081477	Bear Creek Township
081478	Coolidge Township
081479	Kendall Township
081480	Lamont Township
081481	Liberty
081482	Syracuse Township
081483	Hartland Township
081548	Montecello Twp
081549	Wilsey
081550	Ness City
081551	Bazine
081552	Alexander
081553	McCraken
081554	Danville
081555	Anthony
081556	Hunnewell
081557	South Haven
081558	Caldwell
081559	Hazelton
081560	Eureka
081561	Hamilton
081562	Neal
081563	Toronto
081861	Florence
091000	Ky/Mid-States
091001	Ky/Mid-States w/ Liberty
091132	Operations
093000	Mid-States-Tennessee
093130	Union City
093135	Columbia
093140	Shelbyville
093144	Franklin
093145	Murfreesboro
093151	Marysville
093152	Johnson City
093153	Kingsport
093154	Tri-Cities
093155	Greenville
093156	Morristown
093157	Johnson City
093158	Saturn Plant
093159	Elizabethtown
093160	Louisville OS_CL
093161	Maryville IS_CL
093162	Alcoa IS_CL
093163	Never Used
093172	Knoxville OS_CL
093173	Maryville OS_CL
093174	Rockford OS_CL
093175	Gainsville
093180	Columbus
093181	Bristol
093182	Nolensville
093183	Spring Hill
093326	Mosheim
095000	Mid-States-Georgia
095120	Waverly Hall
095125	Oakwood
095175	Gainesville
095180	Columbus
096000	Mid-States-Virginia

Service Area	Description
096135	Columbia
096154	Virginia-Tennessee
096155	Greenville
096163	Abingdon
096164	Marion
096165	Marion
096166	Pulaski
096167	New River
096168	Radford
096169	Radford
096180	Columbus
096181	Atkins
096182	Blackburg
096183	Bristol
096184	Chilhowie
096185	Christiansburg
096186	Dublin
096187	Emory
096188	Fairlawn
096189	Glade Spring
096190	Meadowview
096191	Rural Retreat
096192	Wytheville
098189	Keokuk
107000	AE Louisiana Overhead
170000	Mississippi
170001	Clarkdale
170002	Lyon
170003	Jonestown
170004	Duncan
170005	Lula
170006	Crenshaw
170007	Sledge
170008	Cleveland
170009	Boyle
170010	Pace
170011	Merigold
170012	Rosedale
170013	Shelby
170014	Mound Bayou
170015	Renova
170016	Tunica
170017	Greenville
170018	Arcola
170019	Leland
170020	Benoit
170021	Indianola
170022	Moorhead
170023	Baird
170024	Sunflower
170025	Belzoni
170026	Inverness
170027	Isola
170028	Rolling Fork
170029	Cary
170030	Anguilla
170031	Hollandale
170032	Catledge Farm
170033	Greenwood
170034	Itta Bena
170035	Carrollton
170036	North Carrollton
170037	Grenada
170038	Holcomb
170039	Winona
170040	Yazoo City
170041	Benton
170042	Kosciusko
170043	Carthage
170044	Ethel
170045	Mccool
170046	Durant
170047	Goodman
170048	Pickens
170049	Lexington
170050	Tchula
170051	Louisville
170052	Ackerman
170053	Walthall
170054	Eupora
170055	Mathiston
170056	Maben/Cumberland
170057	Noxapater
170058	Jackson
170059	Clinton
170060	Flowood
170061	Florence
170062	Raymond
170063	Edwards
170064	Bolton
170065	Learned
170066	Pearl
170067	Richland

Service Area	Description
170068	Ridgeland
170069	Madison
170070	Vicksburg
170071	Flora
170072	Natchez
170073	Highland Park
170074	Bude
170075	Roxie
170076	Meadville
170077	Tupelo
170078	Verona
170079	Saltillo
170080	Plantersville
170081	Guntown
170082	Amory
170083	Becker/Pine Grove
170084	Nettleton
170085	Okolona
170086	Hatley
170087	Smithville
170088	Houston
170089	Vardaman
170090	Woodland
170091	Mantee
170092	Calhoun City
170093	Derma
170094	Pittsboro
170095	Bruce
170096	Meridian
170097	Marion
170098	Dekalb
170099	Lucedale
170100	Columbus
170101	Starkville
170102	Macon
170103	Brooksville
170105	West Point
170106	Aberdeen
170107	Hamilton
170108	Southaven
170109	Desotohaven
170110	Horn Lake
170111	Hernando
170112	Coldwater
170113	Olive Branch
170114	Village of Memphis
170115	Pontotoc
170116	Byram
170117	Winstonville
171000	Mississippi PBR
190000	Mid-Tex Gas Division
190025	Forreston
190555	Richardson
190850	Fort Worth
190911	Dallas
196000	City of Dallas
196911	DALLAS_ICL
197000	Dallas Environs
197024	Kaufman County Municipal Utility Distri
198000	Settled Cities
198001	ALVARADO_ICL
198002	BAIRD_ICL
198003	BARDWELL_ICL
198004	PARIS_ICL
198005	BONHAM_ICL
198006	BROWNWOOD_ICL
198007	GAINESVILLE_ICL
198008	BURLESON_ICL
198009	CADDO MILLS_ICL
198010	CARROLLTON_ICL
198011	CEDAR HILL_ICL
198012	CELINA_ICL
198013	CHILLICOTHE_ICL
198014	CLYDE_ICL
198015	COMMERCE_ICL
198016	COVINGTON_ICL
198017	CUMBY_ICL
198018	ELECTRA_ICL
198019	OAKWOOD_ICL
198020	EMHOUSE_ICL
198021	EVERMAN_ICL
198022	FARMERSVILLE_ICL
198023	FERRIS_ICL
198024	FORNEY_ICL
198026	FRISCO_ICL
198027	GARLAND_ICL
198028	GRANDVIEW_ICL
198029	GREENVILLE_ICL
198031	BOYD_ICL
198032	HENRIETTA_ICL
198033	HONEY GROVE_ICL
198034	HUTCHINS_ICL
198035	IRVING_ICL

Service Area	Description
198036	ITALY_ICL
198037	ITASCA_ICL
198038	JOSEPHINE_ICL
198039	JOSHUA_ICL
198040	KAUFMAN_ICL
198041	KEENE_ICL
198042	LANCASTER_ICL
198043	LEWISVILLE_ICL
198044	BEVERLY HILLS_ICL
198045	MANSFIELD_ICL
198046	MAYPEARL_ICL
198047	MESQUITE_ICL
198048	MEXIA_ICL
198049	MIDLOTHIAN_ICL
198050	MORAN_ICL
198051	NEVADA_ICL
198053	PLANO_ICL
198054	PROSPER_ICL
198055	PUTNAM_ICL
198056	RHOME_ICL
198057	RICHARDSON_ICL
198058	RICHLAND_ICL
198059	ROCKWALL_ICL
198060	ROWLETT_ICL
198061	ROYSE CITY_ICL
198062	SANGER_ICL
198063	TERRELL_ICL
198064	VALLEY VIEW-COOKE CO_ICL
198065	VENUS_ICL
198066	VERNON_ICL
198067	WEST_ICL
198068	WORTHAM_ICL
198069	SULPHUR SPRINGS_ICL
198070	TRENTON_ICL
198071	ECTOR_ICL
198072	DODD CITY_ICL
198073	WHITEWRIGHT_ICL
198074	ANNA_ICL
198075	ABBOTT_ICL
198076	BLOOMING GROVE_ICL
198077	BELLS_ICL
198078	BELTON_ICL
198079	COOPER_ICL
198080	CAMPBELL_ICL
198081	CELESTE_ICL
198083	FROST_ICL
198084	LADONIA_ICL0580
198085	LEONARD_ICL
198086	MARLIN_ICL
198087	MART_ICL
198088	PENELOPE_ICL
198089	SAVOY_ICL
198090	VAN ALSTYNE_ICL
198091	WOLFE CITY_ICL
198093	TEMPLE_ICL
198094	WINTERS_ICL
198095	BALLINGER_ICL
198096	TRINIDAD_ICL
198097	SWEETWATER_ICL
198098	MERKEL_ICL
198099	TRENT_ICL
198100	DAWSON_ICL
198101	ROSCOE_ICL
198103	COLORADO CITY_ICL
198104	LORAINE_ICL
198105	HUBBARD_ICL
198106	MALONE_ICL
198107	COOLIDGE_ICL
198108	BRYAN_ICL
198109	TROY_ICL
198110	LORENA_ICL
198111	COLLEGE STATION_ICL
198112	FATE_ICL
198113	BRUCEVILLE EDDY_ICL
198114	WINDOM_ICL
198115	JEWETT_ICL
198116	MOODY_ICL
198117	HEARNE_ICL
198119	MC GREGOR_ICL
198122	DUNCANVILLE_ICL
198123	AUBREY_ICL
198124	COLLINSVILLE_ICL
198125	PILOT POINT_ICL
198147	ALLEN_ICL
198148	STREETMAN_ICL
198151	DEPORT_ICL
198152	AURORA_ICL
198155	SEYMOUR_ICL
198156	BENJAMIN_ICL
198158	MUNDAY_ICL
198159	GOREE_ICL
198160	GRAND PRAIRIE_ICL
198161	KNOX CITY_ICL

Service Area	Description
198162	LACY LAKEVIEW_ICL
198163	WEINERT_ICL
198164	ROCHESTER_ICL
198165	RULE_ICL
198166	HASKELL_ICL
198168	STAMFORD_ICL
198169	HAMLIN_ICL
198170	ARLINGTON_ICL
198171	ROTAN_ICL
198172	ROBY_ICL
198173	ANSON_ICL
198175	BOWIE_ICL
198176	BRIDGEPORT_ICL
198177	BELLEVUE_ICL
198178	ALVORD_ICL
198179	DECATUR_ICL
198180	CLEBURNE_ICL
198181	CORSICANA_ICL
198182	DENTON_ICL
198183	DENISON_ICL
198184	ENNIS_ICL
198185	HILLSBORO_ICL
198186	MC KINNEY_ICL
198187	SHERMAN_ICL
198188	WHITESBORO_ICL
198189	BYERS_ICL
198190	IOWA PARK_ICL
198191	GARRETT_ICL
198192	PETROLIA_ICL
198193	WAXAHACHIE_ICL
198195	BANGS_ICL
198196	CENTERVILLE_ICL
198197	NORMANGEE_ICL
198198	MADISONVILLE_ICL
198199	HICO_ICL
198200	TIOGA_ICL
198201	GATESVILLE_ICL
198202	OGLESBY_ICL
198203	CALVERT_ICL
198204	RIESEL_ICL
198205	ALBANY_ICL
198207	DALWORTHINGTON GARDENS_ICL
198208	GODLEY_ICL
198211	ROXTON_ICL
198212	TEAGUE_ICL
198213	BREMOND_ICL
198214	SNYDER_ICL
198215	WILMER_ICL
198216	CHANDLER_ICL
198217	NOVICE_ICL
198219	BUCKHOLTS_ICL
198220	HOLLAND_ICL
198221	BARTLETT_ICL
198222	ROGERS_ICL
198223	ROCKDALE_ICL
198224	CAMERON_ICL
198225	GRANGER_ICL
198226	GEORGETOWN_ICL
198227	TAYLOR_ICL
198228	SAGINAW_ICL
198229	NEWARK_ICL
198230	MILFORD_ICL
198231	PALMER_ICL
198232	ROUND ROCK_ICL
198233	BELLMEAD_ICL
198234	HUTTO_ICL
198235	LITTLE RIVER ACADEMY_ICL
198236	KERENS_ICL
198237	GROESBECK_ICL
198238	EASTLAND_ICL
198239	POWELL_ICL
198240	BARRY_ICL
198241	WYLIE_ICL
198242	LINDSAY_ICL
198243	MUENSTER_ICL
198245	SAINT JO_ICL
198246	HOWE_ICL
198247	GRAPEVINE_ICL
198248	WHITNEY_ICL
198249	GRANBURY_ICL
198250	RAVENNA_ICL
198251	BROWNSBORO_ICL
198252	GLEN ROSE_ICL
198253	MERIDIAN_ICL
198254	MORGAN_ICL
198255	WALNUT SPRINGS_ICL
198256	CLIFTON_ICL
198257	CLARKSVILLE_ICL
198259	DETROIT_ICL
198260	HAMILTON_ICL
198261	VALLEY MILLS_ICL
198262	CRANDALL_ICL
198263	SEAGOVILLE_ICL

Service Area	Description
198264	MABANK_ICL
198265	KEMP_ICL
198266	ATHENS_ICL
198267	STRAWN_ICL
198271	GORDON_ICL
198273	LOTT_ICL
198274	MALAKOFF_ICL
198275	ROSEBUD_ICL
198276	BLOSSOM_ICL
198277	PECAN GAP_ICL
198278	CHICO_ICL
198281	SCURRY_ICL
198282	TEHUACANA_ICL
198283	IREDELL_ICL
198284	MELISSA_ICL
198285	BUFFALO GAP_ICL
198286	TUSCOLA_ICL
198287	LAWN_ICL
198289	CALDWELL_ICL
198290	KILLEEN_ICL
198291	EUSTACE_ICL
198292	CISCO_ICL
198293	FARMERS BRANCH_ICL
198294	POTTSBORO_ICL
198295	BOGATA_ICL
198296	THORNDALE_ICL
198297	BUFFALO_ICL
198298	THRALL_ICL
198300	FAIRFIELD_ICL
198302	KERRVILLE_ICL
198303	LUEDERS_ICL
198304	FREDERICKSBURG_ICL
198305	LLANO_ICL
198306	SAN SABA_ICL
198307	BURNET_ICL
198308	LAMPASAS_ICL
198309	MARBLE FALLS_ICL
198310	GOLDTHWAITE_ICL
198311	LOMETA_ICL
198312	BERTRAM_ICL
198313	QUITMAN_ICL
198315	EULESS_ICL
198316	HURST_ICL
198317	COMO_ICL
198318	CANTON_ICL
198319	RED OAK_ICL
198320	DESOTO_ICL
198327	O BRIEN_ICL
198328	KELLER_ICL
198329	JUSTIN_ICL
198330	ROANOKE_ICL
198331	LIPAN_ICL
198332	THORNTON_ICL
198334	FRANKLIN_ICL
198335	BANDERA_ICL
198336	LAKE DALLAS_ICL
198337	MURPHY_ICL
198338	ADDISON_ICL
198339	SPRINGTOWN_ICL
198341	BLACKWELL_ICL
198343	BURKBURNETT_ICL
198344	CHILDRESS_ICL
198349	NEWCASTLE_ICL
198352	QUANAH_ICL
198354	PALESTINE_ICL
198356	PLEASANT VALLEY_ICL
198357	SANCTUARY_ICL
198359	AZLE_ICL
198360	TYLER_ICL
198361	WHITEHOUSE_ICL
198362	AUSTIN_ICL
198363	BEDFORD_ICL
198366	BLANKET_ICL
198369	SADLER_ICL
198370	HAWLEY_ICL
198371	HEWITT_ICL
198372	COPPERAS COVE_ICL
198373	NOLANVILLE_ICL
198374	TYE_ICL
198375	RANGER_ICL
198379	ROBINSON_ICL
198382	EARLY_ICL
198384	MURCHISON_ICL
198385	GUNTER_ICL
198386	BALCH SPRINGS_ICL
198388	SUNNYVALE_ICL
198394	NOCONA_ICL
198395	WOODWAY_ICL
198397	SACHSE_ICL
198398	COPPELL_ICL
198399	FRANKSTON_ICL
198400	ABILENE_ICL
198401	BLUE RIDGE_ICL

Service Area	Description
198402	PRINCETON_ICL
198404	ALBA_ICL
198405	POINT_ICL
198406	LONE OAK_ICL
198407	QUINLAN_ICL
198408	EMORY_ICL
198409	CROWLEY_ICL
198411	WATAUGA_ICL
198412	HARKER HEIGHTS_ICL
198413	POYNOR_ICL
198415	KRUM_ICL
198416	PONDER_ICL
198417	CHAPEL HILL_ICL
198418	COLLEYVILLE_ICL
198419	IMPACT_ICL
198421	TOM BEAN_ICL
198423	ROBERT LEE_ICL
198427	KOSSE_ICL
198428	SHADY SHORES_ICL
198429	YANTIS_ICL
198430	BLUM_ICL
198431	RIO VISTA_ICL
198432	PARADISE_ICL
198434	EDOM_ICL
198436	LEXINGTON_ICL
198437	CRAWFORD_ICL
198440	FLOWER MOUND_ICL
198441	HIGHLAND VILLAGE_ICL
198442	MANOR_ICL
198443	PFLUGERVILLE_ICL
198444	MIDWAY_ICL
198446	ARGYLE_ICL
198451	STEPHENVILLE_ICL
198452	COMANCHE_ICL
198453	DUBLIN_ICL
198454	DE LEON_ICL
198455	GUSTINE_ICL
198456	COLEMAN_ICL
198457	SANTA ANNA_ICL
198458	CARBON_ICL
198460	GORMAN_ICL
198461	RENO (LAMAR CO)_ICL
198462	SOUTH MOUNTAIN_ICL
198463	ANNONA_ICL
198464	AVERY_ICL
198465	THROCKMORTON_ICL
198466	SOUTHMAYD_ICL
198467	RUNAWAY BAY_ICL
198469	EVANT_ICL
198477	PANTEGO_ICL
198478	WESTLAKE_ICL
198479	ALMA_ICL
198480	RICE_ICL
198481	STAR HARBOR_ICL
198482	SOMERVILLE_ICL
198483	LAVON_ICL
198485	FAIRVIEW_ICL
198486	HICKORY CREEK_ICL
198487	HEATH_ICL
198488	HASLET_ICL
198489	SOUTHLAKE_ICL
198490	OAK LEAF_ICL
198494	GLENN HEIGHTS_ICL
198495	RETREAT_ICL
198496	LEONA_ICL
198498	LITTLE ELM_ICL
198500	SAN ANGELO_ICL
198502	MILES_ICL
198504	BRONTE_ICL
198505	ARCHER CITY_ICL
198508	HOLLIDAY_ICL
198509	MEGARGEL_ICL
198510	OLNEY_ICL
198511	TOCO_ICL
198512	ANGUS_ICL
198513	ROSS_ICL
198514	CEDAR PARK_ICL
198515	THE COLONY_ICL
198519	CROSS ROADS (DENTON)_ICL
198521	RENO(PARKER CO)_ICL
198522	SUN VALLEY_ICL
198524	CORINTH_ICL
198525	LEANDER_ICL
198526	GOODLOW_ICL
198531	LINCOLN PARK_ICL
198532	KNOLLWOOD_ICL
198533	PECAN HILL_ICL
198534	NORTHLAKE_ICL
198535	CORRAL CITY_ICL
198536	LONGVIEW_ICL
198537	LAKEPORT_ICL
198542	MOBILE CITY_ICL
198545	TROPHY CLUB_ICL

Service Area	Description
198593	KURTEN_ICL
198596	CASHION COMMUNITY_ICL
198600	WICHITA FALLS_ICL
198617	OVILLA_ICL
198630	TALTY_ICL
198638	DOUBLE OAK_ICL
198639	PARKER_ICL
198640	BARTONVILLE_ICL
198644	COPPER CANYON_ICL
198698	WIXON VALLEY_ICL
198700	WACO_ICL
198704	BRAZOS BEND_ICL
198714	JACKSONVILLE_ICL
198715	KILGORE_ICL
198738	POST OAK BEND_ICL
198743	MCLENDON-CHISHOLM_ICL
198744	COYOTE FLATS_ICL
198745	HEBRON_ICL
198746	MILLSAP_ICL
198850	FORT WORTH_ICL
198851	BENBROOK_ICL
198852	EDGECLIFF VILLAGE_ICL
198853	FOREST HILL_ICL
198854	HALTOM CITY_ICL
198855	KENNEDALE_ICL
198856	LAKESIDE_ICL
198857	LAKE WORTH_ICL
198858	NORTH RICHLAND HILLS_ICL
198859	RICHLAND HILLS_ICL
198860	RIVER OAKS_ICL
198861	SANSOM PARK_ICL
198862	WESTOVER HILLS_ICL
198863	WESTWORTH VILLAGE_ICL
198864	WHITE SETTLEMENT_ICL
198865	BLUE MOUND_ICL
198912	HIGHLAND PARK_ICL
198913	UNIVERSITY PARK_ICL
198914	COCKRELL HILL_ICL
200000	Mid-Tex Franchise Fees
200001	Alvarado
200002	Baird
200003	BARDWELL
200004	PARIS
200005	BONHAM
200006	BROWNWOOD
200007	GAINESVILLE
200008	BURLESON
200009	CADDO MILLS
200010	CARROLLTON
200011	CEDAR HILL
200012	CELINA
200013	CHILLICOTHE
200014	CLYDE
200015	COMMERCE
200016	COVINGTON
200017	CUMBY
200018	ELECTRA
200019	OAKWOOD
200020	EMHOUSE
200021	EVERMAN
200022	FARMERSVILLE
200023	FERRIS
200024	FORNEY
200025	FORRESTON
200026	FRISCO
200027	GARLAND
200028	GRANDVIEW
200029	GREENVILLE
200030	HARROLD
200031	BOYD
200032	HENRIETTA
200033	HONEY GROVE
200034	HUTCHINS
200035	IRVING
200036	ITALY
200037	ITASCA
200038	JOSEPHINE
200039	JOSHUA
200040	KAUFMAN
200041	KEENE
200042	LANCASTER
200043	LEWISVILLE
200044	BEVERLY HILLS
200045	MANSFIELD
200046	MAYPEARL
200047	MESQUITE
200048	MEXIA
200049	MIDLOTHIAN
200050	MORAN
200051	NEVADA
200052	OKLAUNION
200053	PLANO
200054	PROSPER

Service Area	Description
200055	PUTNAM
200056	RHOME
200057	RICHARDSON
200058	RICHLAND
200059	ROCKWALL
200060	ROWLETT
200061	ROYSE CITY
200062	SANGER
200063	TERRELL
200064	VALLEY VIEW-COOKE CO
200065	VENUS
200066	VERNON
200067	WEST
200068	WORTHAM
200069	SULPHUR SPRINGS
200070	TRENTON
200071	ECTOR
200072	DODD CITY
200073	WHITEWRIGHT
200074	ANNA
200075	ABBOTT
200076	BLOOMING GROVE
200077	BELLS
200078	BELTON
200079	COOPER
200080	CAMPBELL
200081	CELESTE
200082	FAIRLIE
200083	FROST
200084	LADONIA
200085	LEONARD
200086	MARLIN
200087	MART
200088	PENELOPE
200089	SAVOY
200090	VAN ALSTYNE
200091	WOLFE CITY
200092	WESTMINSTER
200093	TEMPLE
200094	WINTERS
200095	BALLINGER
200096	TRINIDAD
200097	SWEETWATER
200098	MERKEL
200099	TRENT
200100	DAWSON
200101	ROSCOE
200102	TALPA
200103	COLORADO CITY
200104	LORAINE
200105	HUBBARD
200106	MALONE
200107	COOLIDGE
200108	BRYAN
200109	TROY
200110	LORENA
200111	COLLEGE STATION
200112	FATE
200113	BRUCEVILLE-EDDY
200114	WINDOM
200115	JEWETT
200116	MOODY
200117	HEARNE
200118	REAGAN
200119	MCGREGOR
200120	LILLIAN
200122	DUNCANVILLE
200123	AUBREY
200124	COLLINSVILLE
200125	PILOT POINT
200147	ALLEN
200148	STREETMAN
200151	DEPORT
200152	AURORA
200153	ENLOE
200154	RHINELAND
200155	SEYMOUR
200156	BENJAMIN
200157	TRUSCOTT
200158	MUNDAY
200159	GOREE
200160	GRAND PRAIRIE
200161	KNOX CITY
200162	LACY LAKEVIEW
200163	WEINERT
200164	ROCHESTER
200165	RULE
200166	HASKELL
200167	ELM MOTT
200168	STAMFORD
200169	HAMLIN
200170	ARLINGTON
200171	ROTAN

Service Area	Description
200172	ROBY
200173	ANSON
200174	SUNSET
200175	BOWIE
200176	BRIDGEPORT
200177	BELLEVUE
200178	ALVORD
200179	DECATUR
200180	CLEBURNE
200181	CORSICANA
200182	DENTON
200183	DENISON
200184	ENNIS
200185	HILLSBORO
200186	MCKINNEY
200187	SHERMAN
200188	WHITESBORO
200189	BYERS
200190	IOWA PARK
200191	GARRETT
200192	PETROLIA
200193	WAXAHACHIE
200194	ODELL
200195	BANGS
200196	CENTERVILLE
200197	NORMANGEE
200198	MADISONVILLE
200199	HICO
200200	TIOGA
200201	GATESVILLE
200202	OGLESBY
200203	CALVERT
200204	RIESEL
200205	ALBANY
200206	BROOKSTON
200207	DALWORTHINGTON GARDN
200208	GODLEY
200209	PETTY
200210	MONTAGUE
200211	ROXTON
200212	TEAGUE
200213	BREMOND
200214	SNYDER
200215	WILMER
200216	CHANDLER
200217	NOVICE
200218	SANTO
200219	BUCKHOLTS
200220	HOLLAND
200221	BARTLETT
200222	ROGERS
200223	ROCKDALE
200224	CAMERON
200225	GRANGER
200226	GEORGETOWN
200227	TAYLOR
200228	SAGINAW
200229	NEWARK
200230	MILFORD
200231	PALMER
200232	ROUND ROCK
200233	BELLMEAD
200234	HUTTO
200235	LITTLE RIVER-ACADEMY
200236	KERENS
200237	GROESBECK
200238	EASTLAND
200239	POWELL
200240	BARRY
200241	WYLIE
200242	LINDSAY
200243	MUENSTER
200244	MYRA
200245	SAINT JO
200246	HOWE
200247	GRAPEVINE
200248	WHITNEY
200249	GRANBURY
200250	RAVENNA
200251	BROWNSBORO
200252	GLEN ROSE
200253	MERIDIAN
200254	MORGAN
200255	WALNUT SPRINGS
200256	CLIFTON
200257	CLARKSVILLE
200259	DETROIT
200260	HAMILTON
200261	VALLEY MILLS
200262	CRANDALL
200263	SEAGOVILLE
200264	MABANK
200265	KEMP

Service Area	Description
200266	ATHENS
200267	STRAWN
200271	GORDON
200272	VALERA
200273	LOTT
200274	MALAKOFF
200275	ROSEBUD
200276	BLOSSOM
200277	PECAN GAP
200278	CHICO
200279	CHILTON
200280	OSCEOLA
200281	SCURRY
200282	TEHUACANA
200283	IREDELL
200284	MELISSA
200285	BUFFALO GAP
200286	TUSCOLA
200287	LAWN
200289	CALDWELL
200290	KILLEEN
200291	EUSTACE
200292	CISCO
200293	FARMERS BRANCH
200294	POTTSBORO
200295	BOGATA
200296	THORNDALE
200297	BUFFALO
200298	THRALL
200300	FAIRFIELD
200302	KERRVILLE
200303	LUEDERS
200304	FREDERICKSBURG
200305	LLANO
200306	SAN SABA
200307	BURNET
200308	LAMPASAS
200309	MARBLE FALLS
200310	GOLDTHWAITE
200311	LOMETA
200312	BERTRAM
200313	QUITMAN
200315	EULESS
200316	HURST
200317	COMO
200318	CANTON
200319	RED OAK
200320	DESOTO
200324	HERMLEIGH
200325	BRASHEAR
200326	POTTSVILLE
200327	OBRIEN
200328	KELLER
200329	JUSTIN
200330	ROANOKE
200331	LIPAN
200332	THORNTON
200333	CENTER POINT
200334	FRANKLIN
200335	BANDERA
200336	LAKE DALLAS
200337	MURPHY
200338	ADDISON
200339	SPRINGTOWN
200340	COMFORT
200341	BLACKWELL
200343	BURKBURNETT
200344	CHILDRESS
200345	DODSON
200346	JEAN
200347	KIRKLAND
200348	MEMPHIS
200349	NEWCASTLE
200352	QUANAH
200353	WELLINGTON
200354	PALESTINE
200355	LAKEVIEW
200356	PLEASANT VALLEY
200357	SANCTUARY
200358	KAMAY
200359	AZLE
200360	TYLER
200361	WHITEHOUSE
200362	AUSTIN
200363	BEDFORD
200364	SONORA
200365	CHRISTOVAL
200366	BLANKET
200367	MAY
200368	NORTH ZULCH
200369	SADLER
200370	HAWLEY
200371	HEWITT

Service Area	Description
200372	COPPERAS COVE
200373	NOLANVILLE
200374	TYE
200375	RANGER
200376	OLDEN
200378	VERA
200379	ROBINSON
200381	STAR
200382	EARLY
200383	SYLVESTER
200384	MURCHISON
200385	GUNTER
200386	BALCH SPRINGS
200388	SUNNYVALE
200389	WINGATE
200391	CARLSBAD
200392	WELLS BRANCH
200394	NOCONA
200395	WOODWAY
200397	SACHSE
200398	COPPELL
200399	FRANKSTON
200400	ABILENE
200401	BLUE RIDGE
200402	PRINCETON
200404	ALBA
200405	POINT
200406	LONE OAK
200407	QUINLAN
200408	EMORY
200409	CROWLEY
200411	WATAUGA
200412	HARKER HEIGHTS
200413	POYNOR
200415	KRUM
200416	PONDER
200417	CHAPEL HILL
200418	COLLEYVILLE
200419	IMPACT
200420	ELMO
200421	TOM BEAN
200423	ROBERT LEE
200424	TRUMBALL
200425	REESE
200426	PICKTON
200427	KOSSE
200428	SHADY SHORES
200429	YANTIS
200430	BLUM
200431	RIO VISTA
200432	PARADISE
200433	BRISTOL
200434	EDOM
200435	BEN WHEELER
200436	LEXINGTON
200437	CRAWFORD
200439	CAYUGA
200440	FLOWER MOUND
200441	HIGHLAND VILLAGE
200442	MANOR
200443	PFLUGERVILLE
200444	MIDWAY
200446	ARGYLE
200447	RED SPRINGS
200448	NORTHCREST
200449	JOHNTOWN
200451	STEPHENVILLE
200452	COMANCHE
200453	DUBLIN
200454	DE LEON
200455	GUSTINE
200456	COLEMAN
200457	SANTA ANNA
200458	CARBON
200459	DESDEMONA
200460	GORMAN
200461	RENO (LAMAR CO)
200462	SOUTH MOUNTAIN
200463	ANNONA
200464	AVERY
200465	THROCKMORTON
200466	SOUTHMAYD
200467	RUNAWAY BAY
200468	EDEN
200469	EVANT
200471	PADUCAH
200472	CAREY
200473	TELL
200474	NEWLIN ENVIRON
200475	ESTELLINE
200476	GOODLETT
200477	PANTEGO
200478	WESTLAKE

Service Area	Description
200479	ALMA
200480	RICE
200481	STAR HARBOR
200482	SOMERVILLE
200483	LAVON
200485	FAIRVIEW (COLLIN)
200486	HICKORY CREEK
200487	HEATH
200488	HASLET
200489	SOUTHLAKE
200490	OAK LEAF
200492	AVALON
200493	PAINT ROCK
200494	GLENN HEIGHTS
200495	RETREAT
200496	LEONA
200497	SALTILLO
200498	LITTLE ELM
200500	SAN ANGELO
200501	AVOCA
200502	MILES
200503	ROWENA
200504	BRONTE
200505	ARCHER CITY
200506	CLARENDON
200507	HEDLEY
200508	HOLLIDAY
200509	MEGARGEL
200510	OLNEY
200511	TOCO
200512	ANGUS
200513	ROSS
200514	CEDAR PARK
200515	THE COLONY
200516	GRAYSON CO IND PK
200518	TRAVIS
200519	CROSS ROADS (DENTON)
200521	RENO(PARKER CO)
200522	SUN VALLEY
200523	BRUSHY CREEK
200524	CORINTH
200525	LEANDER
200526	GOODLOW
200527	MCCAULLEY
200528	MARSHALL CREEK
200529	BUTTERCUP CREEK
200531	LINCOLN PARK
200532	KNOLLWOOD
200533	PECAN HILL
200534	NORTHLAKE
200535	CORRAL CITY
200536	LONGVIEW
200537	LAKEPORT
200538	ROLLING MEADOWS
200539	BAMBURG
200540	SABINE
200541	LELIA LAKE
200542	MOBILE CITY
200543	SAMNORWOOD
200544	VALLEY VIEW(WICHITA)
200545	TROPHY CLUB
200560	LOFTIN
200580	MAMBRINO
200592	GILLILAND
200593	KURTEN
200596	CASHION COMMUNITY
200597	RIVER CREEK
200598	HORSESHOE
200599	PECANWAY
200600	WICHITA FALLS
200617	OVILLA
200630	TALTY
200638	DOUBLE OAK
200639	PARKER
200640	BARTONVILLE
200644	COPPER CANYON
200698	WIXON VALLEY
200700	WACO
200701	STONEY RIDGE
200702	UNION HILL
200703	CROSSROADS-HENDERSON
200704	BRAZOS BEND
200720	Powderly
200721	SHEPPARD AFB
200732	NAVAL AIR STATION/ JRB
200738	Post Oak Bend
200743	McLendon-Chisholm
200751	DEW
200820	SOMMERVILLE GC107
200850	FORT WORTH
200851	BENBROOK
200852	EDGECLIFF VILLAGE
200853	FOREST HILL

Service Area	Description
200854	HALTOM CITY
200855	KENNEDALE
200856	LAKESIDE
200857	LAKE WORTH
200858	NORTH RICHLAND HILLS
200859	RICHLAND HILLS
200860	RIVER OAKS
200861	SANSOM PARK VILLAGE
200862	WESTOVER HILLS
200863	WESTWORTH VILLAGE
200864	WHITE SETTLEMENT
200865	BLUE MOUND
200867	Rendon
200911	DALLAS
200912	HIGHLAND PARK
200913	UNIVERSITY PARK
200914	COCKRELL HILL
201001	Alvarado Ic_Tp
201002	Baird Ic_Tp
201003	Bardwell Ic_Tp
201004	Paris Ic_Tp
201005	Bonham Ic_Tp
201006	Brownwood Ic_Tp
201007	Gainesville Ic_Tp
201008	Burleson Ic_Tp
201009	Caddo Mills Ic_Tp
201010	Carrollton Ic_Tp
201011	Cedar Hill Ic_Tp
201012	Celina Ic_Tp
201013	Chillicothe Ic_Tp
201014	Clyde Ic_Tp
201015	Commerce Ic_Tp
201016	Covington Ic_Tp
201017	Cumby Ic_Tp
201018	Electra Ic_Tp
201019	Oakwood Ic_Tp
201020	Emhouse Ic_Tp
201021	Everman Ic_Tp
201022	Farmersville Ic_Tp
201023	Ferris Ic_Tp
201024	Forney Ic_Tp
201026	Frisco Ic_Tp
201027	Garland Ic_Tp
201028	Grandview_Ic_Tp
201029	Greenville Ic_Tp
201031	Boyd Ic_Tp
201032	Henrietta Ic_Tp
201033	Honey Grove Ic_Tp
201034	Hutchins Ic_Tp
201035	Irving Ic_Tp
201036	Italy Ic_Tp
201037	Itasca Ic_Tp
201038	Josephine Ic_Tp
201039	Joshua Ic_Tp
201040	Kaufman Ic_Tp
201041	Keene Ic_Tp
201042	Lancaster Ic_Tp
201043	Lewisville Ic_Tp
201044	Beverly Hills Ic_Tp
201045	Mansfield Ic_Tp
201046	Maypearl Ic_Tp
201047	Mesquite Ic_Tp
201048	Mexia Ic_Tp
201049	Midlothian Ic_Tp
201050	Moran Ic_Tp
201051	Nevada Ic_Tp
201053	Plano Ic_Tp
201054	Prosper_Ic_Tp
201055	Putnam Ic_Tp
201056	Rhome Ic_Tp
201058	Richland Ic_Tp
201059	Rockwall Ic_Tp
201060	Rowlett Ic_Tp
201061	Royse City Ic_Tp
201062	Sanger Ic_Tp
201063	Terrell Ic_Tp
201064	Valley View (Cooke Cnty)Ic_Tp
201065	Venus Ic_Tp
201066	Vernon Ic_Tp
201067	West Ic_Tp
201068	Wortham Ic_Tp
201069	Sulphur Springs Ic_Tp
201070	Trenton Ic_Tp
201071	Ector Ic_Tp
201072	Dodd City Ic_Tp
201073	Whitewright Ic_Tp
201074	Anna Ic_Tp
201075	Abbott Ic_Tp
201076	Blooming Grove Ic_Tp
201077	Bells Ic_Tp
201078	Belton Ic_Tp
201079	Cooper Ic_Tp
201080	Campbell Ic_Tp

Service Area	Description
201081	Celeste Ic_Tp
201082	FAIRLIE Ic_Tp
201083	Frost Ic_Tp
201084	Ladonia Ic_Tp
201085	Leonard Ic_Tp
201086	Marlin Ic_Tp
201087	Mart Ic_Tp
201088	Penelope Ic_Tp
201089	Savoy Ic_Tp
201090	Van Alstyne Ic_Tp
201091	Wolfe City Ic_Tp
201093	Temple Ic_Tp
201094	Winters Ic_Tp
201095	Ballinger Ic_Tp
201096	Trinidad Ic_Tp
201097	Sweetwater Ic_Tp
201098	Merkel Ic_Tp
201099	Trent Ic_Tp
201100	Dawson Ic_Tp
201101	Roscoe Ic_Tp
201102	TALPA Ic_Tp
201103	Colorado City Ic_Tp
201104	Loraine Ic_Tp
201105	Hubbard Ic_Tp
201106	Malone Ic_Tp
201107	Coolidge Ic_Tp
201108	Bryan Ic_Tp
201109	Troy Ic_Tp
201110	Lorena Ic_Tp
201112	Fate Ic_Tp
201113	Bruceville-Eddy Ic_Tp
201114	Windom Ic_Tp
201115	Jewett Ic_Tp
201116	Moody Ic_Tp
201117	Hearne Ic_Tp
201119	Mcgregor Ic_Tp
201120	LILLIAN Ic_Tp
201122	Duncanville Ic_Tp
201123	Aubrey Ic_Tp
201124	Collinsville Ic_Tp
201125	Pilot Point Ic_Tp
201147	Allen Ic_Tp
201148	Streetman Ic_Tp
201151	Deport Ic_Tp
201152	Aurora Ic_Tp
201155	Seymour Ic_Tp
201156	Benjamin Ic_Tp
201158	Munday Ic_Tp
201159	Goree Ic_Tp
201160	Grand Prairie Ic_Tp
201161	Knox City Ic_Tp
201162	Lacy Lakeview Ic_Tp
201163	Weinert Ic_Tp
201164	Rochester Ic_Tp
201165	Rule Ic_Tp
201166	Haskell Ic_Tp
201168	Stamford Ic_Tp
201169	Hamlin Ic_Tp
201171	Rotan Ic_Tp
201172	Roby Ic_Tp
201173	Anson Ic_Tp
201174	Sunset Ic_Tp
201175	Bowie Ic_Tp
201176	Bridgeport Ic_Tp
201177	Bellevue Ic_Tp
201178	Alvord Ic_Tp
201179	Decatur Ic_Tp
201180	Cleburne Ic_Tp
201181	Corsicana Ic_Tp
201182	Denton Ic_Tp
201183	Denison Ic_Tp
201184	Ennis Ic_Tp
201185	Hillsboro Ic_Tp
201186	McKinney Ic_Tp
201187	Sherman Ic_Tp
201188	Whitesboro Ic_Tp
201189	Byers Ic_Tp
201190	Iowa Park Ic_Tp
201191	Garrett Ic_Tp
201192	Petrolia Ic_Tp
201193	Waxahachie Ic_Tp
201195	Bangs Ic_Tp
201196	Centerville Ic_Tp
201197	Normangee Ic_Tp
201198	Madisonville Ic_Tp
201199	Hico Ic_Tp
201200	Tioga Ic_Tp
201201	Gatesville Ic_Tp
201202	Oglesby Ic_Tp
201203	Calvert Ic_Tp
201204	Riesel Ic_Tp
201205	Albany Ic_Tp
201207	Dal Worthington Gardn Ic_Tp

Service Area	Description
201208	Godley Ic_Tp
201210	Montague Unincorporated_Ic_Tp
201211	Roxton Ic_Tp
201212	Teague Ic_Tp
201213	Bremond Ic_Tp
201214	Snyder Ic_Tp
201215	Wilmer Ic_Tp
201216	Chandler Ic_Tp
201217	Novice Ic_Tp
201218	SANTO Ic_Tp
201219	Buckholts Ic_Tp
201220	Holland Ic_Tp
201221	Bartlett Ic_Tp
201222	Rogers Ic_Tp
201223	Rockdale Ic_Tp
201224	Cameron Ic_Tp
201225	Granger Ic_Tp
201226	Georgetown Ic_Tp
201227	Taylor Ic_Tp
201228	Saginaw Ic_Tp
201229	Newark Ic_Tp
201230	Milford Ic_Tp
201231	Palmer Ic_Tp
201232	Round Rock Ic_Tp
201233	Bellmead Ic_Tp
201234	Hutto Ic_Tp
201235	Little River Acad Ic_Tp
201236	Kerens Ic_Tp
201237	Groesbeck Ic_Tp
201238	Eastland Ic_Tp
201239	Powell Ic_Tp
201240	Barry Ic_Tp
201242	Lindsay Ic_Tp
201243	Muenster Ic_Tp
201245	Saint Jo Ic_Tp
201246	Howe Ic_Tp
201247	Grapevine Ic_Tp
201248	Whitney Ic_Tp
201249	Granbury Ic_Tp
201250	Ravenna Ic_Tp
201251	Brownsboro Ic_Tp
201252	Glen Rose Ic_Tp
201253	Meridian Ic_Tp
201254	Morgan Ic_Tp
201255	Walnut Springs Ic_Tp
201256	Clifton Ic_Tp
201257	Clarksville Ic_Tp
201259	Detroit Ic_Tp
201260	Hamilton Ic_Tp
201261	Valley Mills Ic_Tp
201262	Crandall Ic_Tp
201263	Seagoville
201264	Mabank Ic_Tp
201265	Kemp Ic_Tp
201266	Athens Ic_Tp
201267	Strawn Ic_Tp
201271	Gordon Ic_Tp
201272	Valera (Unincorporated)_Ic_Tp
201273	Lott Ic_Tp
201274	Malakoff Ic_Tp
201275	Rosebud-Lott Ic_Tp
201276	Blossom Ic_Tp
201277	Pecan Gap (Fannin Cnty) Ic_Tp
201278	Chico Ic_Tp
201279	Chilton (Unincorporated)_Ic_Tp
201282	Tehuacana Ic_Tp
201283	Iredell Ic_Tp
201284	Melissa Ic_Tp
201285	Buffalo Gap Ic_Tp
201286	Tuscola Ic_Tp
201287	Lawn Ic_Tp
201289	Caldwell Ic_Tp
201290	Killeen Ic_Tp
201291	Eustace Ic_Tp
201292	Cisco Ic_Tp
201294	Pottsboro Ic_Tp
201295	Bogata Ic_Tp
201296	Thorndale Ic_Tp
201297	Buffalo Ic_Tp
201298	Thrall Ic_Tp
201300	Fairfield Ic_Tp
201302	Kerrville Ic_Tp
201303	Lueders Ic_Tp
201304	Fredericksburg Ic_Tp
201305	Llano Ic_Tp
201306	San Saba Ic_Tp
201307	Burnet Ic_Tp
201308	Lampasas Ic_Tp
201309	Marble Falls Ic_Tp
201310	Goldthwaite Ic_Tp
201311	Lometa Ic_Tp
201312	Bertram Ic_Tp
201313	Quitman Ic_Tp

Service Area	Description
201315	Euless Ic_Tp
201316	Hurst Ic_Tp
201317	Como Ic_Tp
201318	Canton Ic_Tp
201319	Red Oak Ic_Tp
201320	De Soto Ic_Tp
201324	Hermleigh Unincorp_Ic_Tp
201325	Brashear Unincorporated_Ic_Tp
201326	Pottsville Unincorp_Ic_Tp
201327	O'Brien Ic_Tp
201328	Keller Ic_Tp
201329	Justin Ic_Tp
201330	Roanoke Ic_Tp
201331	Lipan Ic_Tp
201332	Thornton Ic_Tp
201333	Center Point Ic_Tp
201334	Franklin Ic_Tp
201335	Bandera Ic_Tp
201336	Lake Dallas Ic_Tp
201337	Murphy Ic_Tp
201338	Addison Ic_Tp
201339	Springtown Ic_Tp
201340	Comfort (Unincorporated)_Ic_Tp
201341	Blackwell Ic_Tp
201343	Burkburnett Ic_Tp
201344	Childress Ic_Tp
201345	Dodson Ic_Tp
201348	Memphis Ic_Tp
201349	Newcastle Ic_Tp
201352	Quanah Ic_Tp
201353	Wellington Ic_Tp
201354	Palestine Ic_Tp
201355	Lakeview Ic_Tp
201356	Pleasant Valley Ic_Tp
201357	Sanctuary Ic_Tp
201359	Azle Ic_Tp
201360	Tyler Ic_Tp
201361	Whitehouse Ic_Tp
201362	Austin Ic_Tp
201363	Bedford Ic_Tp
201364	Sonora Ic_Tp
201366	Blanket Ic_Tp
201369	Sadler Ic_Tp
201370	Hawley Ic_Tp
201371	Hewitt Ic_Tp
201372	Copperas Cove Ic_Tp
201373	Nolanville Ic_Tp
201374	Tye Ic_Tp
201375	Ranger Ic_Tp
201379	Robinson_IC_TP
201382	Early Ic_Tp
201384	Murchison Ic_Tp
201385	Gunter Ic_Tp
201386	Balch Springs Ic_Tp
201388	Sunnyvale Ic_Tp
201391	Carlsbad_Ic_Tp
201394	Nocona Ic_Tp
201395	Woodway Ic_Tp
201397	Sachse Ic_Tp
201398	Coppell Ic_Tp
201399	Frankston Ic_Tp
201400	Abilene Ic_Tp
201401	Blue Ridge Ic_Tp
201402	Princeton Ic_Tp
201404	Alba Ic_Tp
201405	Point Ic_Tp
201406	Lone Oak Ic_Tp
201407	Quinlan Ic_Tp
201408	Emory Ic_Tp
201409	Crowley Ic_Tp
201411	Watauga Ic_Tp
201412	Harker Heights Ic_Tp
201413	Poynor_Ic_Tp
201415	Krum Ic_Tp
201416	Ponder Ic_Tp
201417	Chapel Hill Ic_Tp
201418	Colleyville Ic_Tp
201419	Impact Ic_Tp
201421	Tom Bean Ic_Tp
201423	Robert Lee Ic_Tp
201426	Pickton (Unincorporated)_Ic_Tp
201427	Kosse Ic_Tp
201428	Shady Shores Ic_Tp
201429	Yantis Ic_Tp
201430	Blum Ic_Tp
201431	Rio Vista Ic_Tp
201432	Paradise Ic_Tp
201434	Edom Ic_Tp
201436	Lexington Ic_Tp
201437	Crawford Ic_Tp
201439	Cayuga Ic_Tp
201440	Flower Mound Ic_Tp
201441	Highland Village Ic_Tp

Service Area	Description
201442	Manor lc_Tp
201443	Pflugerville lc_Tp
201444	Midway lc_Tp
201446	Argyle lc_Tp
201451	Stephenville lc_Tp
201452	Comanche lc_Tp
201453	Dublin lc_Tp
201454	De Leon lc_Tp
201455	Gustine lc_Tp
201456	Coleman lc_Tp
201457	Santa Anna lc_Tp
201458	Carbon lc_Tp
201459	Desdemona Unincorp_lc_Tp
201460	Gorman lc_Tp
201461	Reno - Lamar Co lc_Tp
201462	South Mountain_Unincorp_lc_Tp
201463	Annona lc_Tp
201464	Avery lc_Tp
201465	Throckmorton lc_Tp
201466	Southmayd lc_Tp
201467	Runaway Bay lc_Tp
201468	Eden lc_Tp
201469	Evant_lc_Tp
201471	Paducah lc_Tp
201475	Estelline lc_Tp
201477	Pantego lc_Tp
201478	Westlake lc_Tp
201479	Alma lc_Tp
201480	Rice lc_Tp
201481	Star Harbor lc_Tp
201482	Somerville lc_Tp
201483	Lavon lc_Tp
201485	Fairview (Collin County) lc_Tp
201486	Hickory Creek lc_Tp
201487	Heath lc_Tp
201488	Haslet lc_Tp
201489	Southlake lc_Tp
201493	Paint Rock lc_Tp
201494	Retreat lc_Tp
201495	Retreat lc_Tp
201496	Leona lc_Tp
201500	San Angelo lc_Tp
201502	Miles lc_Tp
201503	Rowena (Unincorporated)_lc_Tp
201504	Bronte lc_Tp
201505	Archer City lc_Tp
201506	Clarendon lc_Tp
201507	Hedley lc_Tp
201508	Holliday lc_Tp
201509	Megargel lc_Tp
201510	Olney lc_Tp
201511	Toco lc_Tp
201512	Angus lc_Tp
201513	Ross lc_Tp
201514	Cedar Park lc_Tp
201515	The Colony lc_Tp
201516	Grayson Co Ind Pk IC_TP
201519	Cross Roads (Denton) lc_Tp
201521	Reno)(Parker Co) lc_Tp
201522	Sun Valley lc_Tp
201524	Corinth lc_Tp
201525	Leander lc_Tp
201526	Goodlow lc_Tp
201528	Marshall Creek lc_Tp
201531	Lincoln Park lc_Tp
201532	Knollwood lc_Tp
201533	Pecan Hill lc_Tp
201534	Northlake lc_Tp
201535	Corral City lc_Tp
201536	Longview (Gregg Cnty) lc_Tp
201537	Lakeport lc_Tp
201538	Rolling Meadows Unincorp_lc_Tp
201542	Mobile City lc_Tp
201545	Trophy Club lc_Tp
201580	Mambrino lc_Tp
201596	Cashion Community lc_Tp
201600	Wichita Falls_Wichita Cy_lc_Tp
201617	Ovilla lc_Tp
201630	Talty lc_Tp
201638	Double Oak lc_Tp
201639	Parker lc_Tp
201644	Copper Canyon lc_Tp
201700	Waco lc_Tp
201850	Fort Worth lc_Tp
201852	Edgecliff Village lc_Tp
201853	Forest Hill lc_Tp
201855	Kennedale lc_Tp
201856	Lakeside lc_Tp
201857	Lake Worth lc_Tp
201858	North Richland Hills lc_Tp
201859	Richland Hills lc_Tp
201860	River Oaks lc_Tp
201861	Sansom Park Village lc_Tp

Service Area	Description
201862	Westover Hills Ic_Tp
201863	Westworth Village Ic_Tp
201864	White Settlement Ic_Tp
201865	Blue Mound Ic_Tp
201911	Dallas Ic_Tp
201912	Highland Park Ic_Tp
201913	University Park Ic_Tp
201914	Cockrell Hill Ic_Tp
201999	Mid Tex Estimate-Town inside city
202001	Alvarado Oc_Tp
202002	Baird Oc_Tp
202003	Bardwell_Oc_Tp
202004	Paris Oc_Tp
202005	Bonham Oc_Tp
202006	Brownwood Oc_Tp
202007	Gainesville Oc_Tp
202009	Caddo Mills Oc_Tp
202012	CELINA Oc_Tp
202013	Chillicothe Oc_Tp
202014	Clyde Oc_Tp
202015	Commerce Oc_Tp
202018	Electra Oc_Tp
202019	Oakwood Oc_Tp
202022	Farmersville Oc_Tp
202023	Ferris Oc_Tp
202024	Forney Oc_Tp
202025	Forreston Oc_Tp
202028	Grandview_Oc_Tp
202029	Greenville Oc_Tp
202030	Harrold (Unincorporated)_Oc_Tp
202032	Henrietta Oc_Tp
202033	Honey Grove Oc_Tp
202036	Italy Oc_Tp
202039	Joshua_Oc_Tp
202040	Kaufman Oc_Tp
202041	Keene Oc_Tp
202042	Lancaster Oc_Tp
202043	Lewisville Oc_Tp
202048	Mexia Oc_Tp
202049	Midlothian Oc_Tp
202050	Moran Oc_Tp
202051	Nevada Oc_Tp
202052	Oklaunion Unincorp_Oc_Tp
202059	Rockwall Oc_Tp
202061	Royse City Oc_Tp
202063	Terrell Oc_Tp
202066	Vernon Oc_Tp
202067	West Oc_Tp
202069	Sulphur Springs Oc_Tp
202073	WHITEWRIGHT Oc_Tp
202076	Blooming Grove Oc_Tp
202077	Bells Oc_Tp
202078	Belton Oc_Tp
202079	Cooper Oc_Tp
202082	Fairlie (Unincorporated)_Oc_Tp
202084	Ladonia Oc_Tp
202085	Leonard Oc_Tp
202086	Marlin Oc_Tp
202087	Mart Oc_Tp
202088	Penelope Oc_Tp
202090	Van Alstyne Oc_Tp
202091	Wolfe City Oc_Tp
202093	Temple Oc_Tp
202094	Winters Oc_Tp
202095	Ballinger Oc_Tp
202097	Sweetwater Oc_Tp
202098	Merkel Oc_Tp
202099	Trent Oc_Tp
202102	Talpa (Unincorporated)_Oc_Tp
202103	Colorado City Oc_Tp
202105	Hubbard Oc_Tp
202106	Malone Oc_Tp
202107	Coolidge Oc_Tp
202108	Bryan Oc_Tp
202117	Hearne Oc_Tp
202118	Reagan (Unincorporated)_Oc_Tp
202119	Mcgregor Oc_Tp
202120	Lillian (Unincorporated)_Oc_Tp
202123	Aubrey Oc_Tp
202124	Collinsville Oc_Tp
202125	Pilot Point Oc_Tp
202153	Enloe (Unincorporated)_Oc_Tp
202154	Rhineland Unincorporated_Oc_Tp
202155	Seymour Oc_Tp
202157	Truscott Unincorporated_Oc_Tp
202158	Munday Oc_Tp
202159	Goree Oc_Tp
202161	Knox City Oc_Tp
202164	Rochester Oc_Tp
202166	Haskell Oc_Tp
202167	Elm Mott Unincorporated_Oc_Tp
202168	Stamford Oc_Tp
202169	Hamlin Oc_Tp

Service Area	Description
202173	Anson Oc_Tp
202174	Sunset Oc_Tp
202175	Bowie Oc_Tp
202176	Bridgeport Oc_Tp
202177	Bellevue Oc_Tp
202179	Decatur Oc_Tp
202180	Cleburne Oc_Tp
202181	Corsicana Oc_Tp
202182	Denton Oc_Tp
202183	Denison Oc_Tp
202184	Ennis Oc_Tp
202185	Hillsboro Oc_Tp
202186	McKinney Oc_Tp
202187	Sherman Oc_Tp
202188	Whitesboro Oc_Tp
202189	Byers Oc_Tp
202190	Iowa Park Oc_Tp
202192	Petrolia Oc_Tp
202193	Waxahachie Oc_Tp
202194	Odell (Unincorporated)_Oc_Tp
202195	Bangs Oc_Tp
202196	Centerville Oc_Tp
202197	Normangee Oc_Tp
202198	Madisonville Oc_Tp
202199	Hico Oc_Tp
202200	Tioga Oc_Tp
202201	Gatesville Oc_Tp
202203	Calvert Oc_Tp
202205	Albany Oc_Tp
202206	Brookston Unincorp_Oc_Tp
202209	Petty (Unincorporated)_Oc_Tp
202210	Montague Unincorporated_Oc_Tp
202211	Roxton Oc_Tp
202212	Teague Oc_Tp
202214	Snyder Oc_Tp
202218	Santo (Unincorporated)_Oc_Tp
202221	Bartlett Oc_Tp
202224	Cameron Oc_Tp
202225	Granger Oc_Tp
202232	Round Rock Oc_Tp
202234	Hutto Oc_Tp
202237	Groesbeck Oc_Tp
202238	Eastland Oc_Tp
202247	GRAPEVINE Oc_Tp
202248	Whitney Oc_Tp
202249	Granbury Oc_Tp
202251	Brownsboro Oc_Tp
202252	Glen Rose Oc_Tp
202254	Morgan Oc_Tp
202255	Walnut Springs Oc_Tp
202256	Clifton Oc_Tp
202257	Clarksville Oc_Tp
202259	Detroit Oc_Tp
202260	Hamilton Oc_Tp
202261	Valley Mills Oc_Tp
202262	Crandall Oc_Tp
202266	Athens Oc_Tp
202267	Strawn Oc_Tp
202272	Valera (Unincorporated)_Oc_Tp
202273	Lott-Rosebud OC_TP
202274	MALAKOFF OC_TP
202275	Rosebud Oc_Tp
202279	Chilton (Unincorporated)_Oc_Tp
202280	Osceola (Unincorporated)_Oc_Tp
202283	Iredell Oc_Tp
202286	Tuscola Oc_Tp
202287	Lawn Oc_Tp
202289	Caldwell Oc_Tp
202290	Killeen Oc_Tp
202291	Eustace Oc_Tp
202292	Cisco Oc_Tp
202294	Pottsboro Oc_Tp
202296	Thorndale Oc_Tp
202297	Buffalo Oc_Tp
202300	Fairfield Oc_Tp
202302	Kerrville Oc_Tp
202303	Lueders Oc_Tp
202304	Fredericksburg Oc_Tp
202305	Llano Oc_Tp
202306	San Saba Oc_Tp
202307	Burnet Oc_Tp
202308	Lampasas Oc_Tp
202309	Marble Falls Oc_Tp
202310	Goldthwaite Oc_Tp
202313	Quitman Oc_Tp
202318	Canton Oc_Tp
202319	Red Oak Oc_Tp
202320	DESOTO Oc_Tp
202324	Hermleigh Unincorp_Oc_Tp
202325	Brashear Unincorporated_Oc_Tp
202326	Pottsville Unincorp_Oc_Tp
202327	O'Brien Oc_Tp
202333	Center Point Oc_Tp

Service Area	Description
202334	Franklin Oc_Tp
202335	Bandera Oc_Tp
202340	Comfort (Unincorporated)_Oc_Tp
202341	Blackwell Oc_Tp
202343	Burkburnett Oc_Tp
202344	Childress Oc_Tp
202345	Dodson Oc_Tp
202346	Jean (Unincorporated)_Oc_Tp
202347	Kirkland Unincorporated_Oc_Tp
202348	Memphis Oc_Tp
202349	Newcastle Oc_Tp
202352	Quanah Oc_Tp
202353	Wellington Oc_Tp
202354	Palestine Oc_Tp
202358	Kamay (Unincorporated)_Oc_Tp
202360	Tyler Oc_Tp
202361	Whitehouse Oc_Tp
202364	Sonora Oc_Tp
202365	Christoval Unincorp_Oc_Tp
202366	Blanket Oc_Tp
202367	May (Unincorporated)_Oc_Tp
202368	North Zulch Unincorp_Oc_Tp
202371	Hewitt Oc_Tp
202374	Tye Oc_Tp
202375	Ranger Oc_Tp
202376	Olden (Unincorporated)_Oc_Tp
202378	Vera (Unincorporated)_Oc_Tp
202381	Star (Unincorporated)_Oc_Tp
202382	Early Oc_Tp
202383	Sylvester Oc_Tp
202385	Gunter Oc_Tp
202389	Wingate (Unincorporated)_Oc_Tp
202391	Carlsbad_Oc_Tp
202394	Nocona Oc_Tp
202399	Frankston Oc_Tp
202400	Abilene Oc_Tp
202404	Alba Oc_Tp
202406	Lone Oak Oc_Tp
202407	Quinlan Oc_Tp
202408	Emory Oc_Tp
202412	Harker Heights Oc_Tp
202413	Poynor_Oc_Tp
202415	Krum Oc Tp
202417	Chapel Hill Oc_Tp
202420	Elmo (Unincorporated)_Oc_Tp
202423	Robert Lee Oc_Tp
202424	Trumbull (Unincorp)_Oc_Tp
202425	Reese(Unincorporated)_Oc_Tp
202426	Pickton (Unincorporated)_Oc_Tp
202430	Blum Oc_Tp
202432	Paradise Oc_Tp
202433	Bristol (Unincorporated)_Oc_Tp
202435	Ben Wheeler Unincorp_Oc_Tp
202436	Lexington Oc_Tp
202437	Crawford Oc_Tp
202439	Cayuga Oc_Tp
202442	Manor Oc_Tp
202446	Argyle Oc_Tp
202447	Red Springs Oc_Tp
202449	Johntown Unincorporated_Oc_Tp
202451	Stephenville Oc_Tp
202452	Comanche Oc_Tp
202453	Dublin Oc_Tp
202454	De Leon Oc_Tp
202456	Coleman Oc_Tp
202457	Santa Anna Oc_Tp
202458	Carbon Oc_Tp
202459	Desdemona Unincorp_Oc_Tp
202460	Gorman Oc_Tp
202462	South Mountain_Unincorp_Oc_Tp
202465	Throckmorton Oc_Tp
202468	Eden Oc_Tp
202469	Evant_Oc_Tp
202471	Paducah Oc_Tp
202472	Carey (Unincorporated)_Oc_Tp
202473	Tell (Unincorporated)_Oc_Tp
202475	Estelline Oc_Tp
202476	Goodlet (Unincorporated)_Oc_Tp
202481	Star Harbor Oc_Tp
202482	Somerville_OC_Tp
202492	Avalon (Unincorporated)_Oc_Tp
202497	Saltillo (Unincorp)_Oc_Tp
202500	San Angelo Oc_Tp
202501	Avoca (Unincorporated)_Oc_Tp
202503	Rowena (Unincorporated)_Oc_Tp
202505	Archer City Oc_Tp
202506	Clarendon Oc_Tp
202507	Hedley Oc_Tp
202509	Megargel Oc_Tp
202510	Olney Oc_Tp
202513	Ross Oc_Tp
202515	The Colony_Environs
202516	Grayson Cty Ind Park_Oc_Tp

Service Area	Description
202527	Mccauley Unincorp_Oc_Tp
202531	Lincoln Park Oc_Tp
202536	Longview (Gregg Cnty) Oc_Tp
202537	Lakeport Oc_Tp
202538	Rolling Meadows Unincorp_Oc_Tp
202539	Bamburg Oc_Tp
202540	Sabine Oc_Tp
202541	Lelia Lake Unincorp_Oc_Tp
202543	Samnorwood (Unincorp)_Oc_Tp
202544	Valley View_Uninc_Wic Co_Oc_Tp
202560	Loftin Oc_Tp
202580	Mambrino Oc_Tp
202592	Gilliland_OC_TP
202597	River Creek Unincorp_Oc_Tp
202598	Horseshoe Unincorporated_Oc_Tp
202599	Pecanway(Unincorporated)_Oc_Tp
202600	Wichita Falls_Wichita Cy_Oc_Tp
202700	Waco Oc_Tp
202701	Stoney Ridge OC TP
202702	Union Hill_OC_TP
202703	Crossroads Oc_Tp
202751	Dew_Oc_Tp
202911	Dallas_Oc_Tp
203002	Baird Ic_Ml
203004	Paris Ic_Ml
203005	Bonham Ic_Ml
203006	Brownwood Ic_Ml
203007	Gainesville Ic_Ml
203008	Burleson Ic_Ml
203010	Carrollton Ic_Ml
203011	Cedar Hill Ic_Ml
203012	Celina Ic_Ml
203014	Clyde Ic_Ml
203015	Commerce Ic_Ml
203018	Electra Ic_Ml
203022	Farmersville Ic_Ml
203023	Ferris Ic_Ml
203024	Forney Ic_Ml
203026	Frisco Ic_Ml
203027	Garland Ic_Ml
203028	Grandview_Ic_Ml
203029	Greenville Ic_Ml
203032	Henrietta Ic_Ml
203033	Honey Grove Ic_Ml
203034	Hutchins Ic_Ml
203035	Irving Ic_Ml
203036	Italy Ic_Ml
203038	Josephine Ic_Ml
203039	Joshua Ic_Ml
203040	Kaufman Ic_Ml
203041	Keene Ic_Ml
203042	Lancaster Ic_Ml
203043	Lewisville Ic_Ml
203045	Mansfield Ic_Ml
203047	Mesquite Ic_Ml
203048	Mexia Ic_Ml
203049	Midlothian Ic_Ml
203053	Plano Ic_Ml
203054	Prosper_Ic_Ml
203056	RHOME Ic_Ml
203058	Richland Ic_Ml
203059	Rockwall Ic_Ml
203060	Rowlett Ic_Ml
203061	Royse City Ic_Ml
203062	Sanger Ic_Ml
203063	Terrell Ic_Ml
203066	Vernon Ic_Ml
203068	Wortham Ic_Ml
203069	Sulphur Springs Ic_Ml
203071	Ector Ic_Ml
203072	Dodd City Ic_Ml
203073	Whitewright Ic_Ml
203074	Anna Ic_Ml
203076	Blooming Grove Ic_Ml
203078	Belton Ic_Ml
203079	Cooper Ic_Ml
203085	Leonard Ic_Ml
203086	Marlin Ic_Ml
203089	Savoy Ic_Ml
203090	Van Alstyne Ic_Ml
203091	Wolfe City Ic_Ml
203093	Temple Ic_Ml
203095	Ballinger Ic_Ml
203096	Trinidad Ic_Ml
203097	Sweetwater Ic_Ml
203101	Roscoe Ic_Ml
203103	Colorado City Ic_Ml
203108	Bryan Ic_Ml
203109	Troy Ic_Ml
203110	Lorena Ic_Ml
203111	College Station Ic_Ml
203112	Fate Ic_Ml
203115	Jewett Ic_Ml

Service Area	Description
203116	Moody lc_Ml
203117	Hearne lc_Ml
203119	Mcgregor lc_Ml
203123	Aubrey lc_Ml
203125	Pilot Point_lc_Ml
203147	Allen_lc_Ml
203152	Aurora lc_Ml
203158	Munday lc_Ml
203160	Grand Prairie lc_Ml
203161	Knox City lc_Ml
203162	Lacy-Lakeview lc_Ml
203166	Haskell lc_Ml
203170	Arlington lc_Ml
203171	Rotan lc_Ml
203175	Bowie lc_Ml
203176	Bridgeport lc_Ml
203179	Decatur lc_Ml
203180	Cleburne lc_Ml
203181	Corsicana lc_Ml
203182	Denton lc_Ml
203183	Denison lc_Ml
203184	Ennis lc_Ml
203185	Hillsboro lc_Ml
203186	McKinney lc_Ml
203187	Sherman lc_Ml
203188	Whitesboro lc_Ml
203190	Iowa Park lc_Ml
203193	Waxahachie lc_Ml
203201	Gatesville lc_Ml
203205	Albany lc_Ml
203212	Teague lc_Ml
203214	Snyder lc_Ml
203215	Wilmer lc_Ml
203216	Chandler lc_Ml
203222	Rogers_lc_Ml
203223	Rockdale lc_Ml
203226	Georgetown lc_Ml
203227	Taylor lc_Ml
203228	Saginaw lc_Ml
203230	Milford lc_Ml
203232	Round Rock lc_Ml
203233	Bellmead lc_Ml
203234	Hutto lc_Ml
203235	Little River Acad lc_Ml
203236	Kerens lc_Ml
203237	Groesbeck lc_Ml
203238	Eastland lc_Ml
203240	Barry lc_Ml
203241	Wylie lc_Ml
203242	Lindsay lc_Ml
203243	Muenster lc_Ml
203249	Granbury lc_Ml
203250	Ravenna lc_Ml
203251	BROWNSBORO lc_Ml
203253	Meridian lc_Ml
203255	Walnut Springs lc_Ml
203256	Clifton lc_Ml
203259	Detroit lc_Ml
203260	Hamilton lc_Ml
203262	Crandall lc_Ml
203263	Seagoville lc_Ml
203266	Athens lc_Ml
203273	Lott lc_Ml
203274	Malakoff lc_Ml
203276	Blossom lc_Ml
203285	Buffalo Gap lc_Ml
203286	Tuscola lc_Ml
203287	Lawn lc_Ml
203289	Caldwell lc_ML
203290	Killeen lc_Ml
203291	Eustace lc_Ml
203292	Cisco lc_Ml
203294	Pottsboro lc_Ml
203297	Buffalo lc_Ml
203302	Kerrville lc_Ml
203307	Burnet lc_Ml
203308	Lampasas lc_Ml
203315	Euless lc_Ml
203316	Hurst lc_Ml
203317	Como lc_Ml
203319	Red Oak lc_Ml
203320	De Soto lc_Ml
203328	Keller lc_Ml
203333	Center Point lc_Ml
203334	Franklin lc_Ml
203336	Lake Dallas lc_Ml
203337	Murphy lc_Ml
203339	Springtown lc_Ml
203343	Burkburnett lc_Ml
203344	Childress lc_Ml
203348	Memphis lc_Ml
203354	Palestine lc_Ml
203357	Sanctuary_lc_Ml

Service Area	Description
203359	Azle Ic_Ml
203360	Tyler Ic_Ml
203361	Whitehouse Ic_Ml
203362	Austin Ic_Ml
203372	Copperas Cove Ic_Ml
203373	Nolanville Ic_Ml
203374	Tye Ic_Ml
203379	Robinson Ic_Ml
203382	Early Ic_Ml
203386	Balch Springs Ic_Ml
203388	Sunnyvale Ic_Ml
203394	Nocona_IC_ML
203395	WOODWAY Ic_Ml
203398	Coppell Ic_Ml
203399	Frankston Ic_Ml
203400	Abilene Ic_Ml
203409	Crowley Ic_Ml
203416	Ponder Ic_Ml
203417	Chapel Hill Ic_Ml
203418	Colleyville Ic_Ml
203428	Shady Shores Ic_Ml
203434	Edom Ic_Ml
203435	BEN WHEELER Ic_Ml
203436	Lexington_Ic_Ml
203440	Flower Mound Ic_Ml
203441	Highland Village Ic_Ml
203443	Pflugerville Ic_Ml
203446	Argyle IC_ML
203451	Stephenville Ic_Ml
203452	Comanche Ic_Ml
203454	De Leon Ic_Ml
203460	Gorman Ic_Ml
203461	Reno - Lamar Co Ic_Ml
203466	Southmayd Ic_Ml
203475	Estelline Ic_Ml
203479	Alma Ic_Ml
203485	Fairview (Collin County) Ic_Ml
203486	Hickory Creek_IC_ML
203487	Heath Ic_Ml
203488	Haslet Ic_Ml
203489	Southlake Ic_Ml
203495	Retreat Ic_Ml
203496	Leona Ic_Ml
203498	Little Elm Ic_Ml
203500	San Angelo Ic_Ml
203505	Archer City Ic_Ml
203511	Toco Ic_Ml
203512	Angus Ic_Ml
203514	Cedar Park Ic_Ml
203515	The Colony Ic_Ml
203519	Cross Roads Ic_Ml
203521	Reno - Parker Co Ic_Ml
203522	Sun Valley Ic_Ml
203524	Corinth_IC_ML
203525	Leander Ic_Ml
203533	Pecan Hill Ic_Ml
203534	Northlake Ic_Ml
203535	Corral City Ic_Ml
203536	Longview (Gregg Cnty) Ic_Ml
203542	Mobile City Ic_Ml
203545	Trophy Club Ic_Ml
203593	Kurten_Ic_Ml
203600	Wichita Falls_Wichita Cy_Ic_Ml
203630	Talty_IC_ML
203640	Bartonville IC_ML
203698	Wixon Valley_Ic_Ml
203700	Waco Ic_Ml
203720	POWDERLY Ic_Ml
203735	MILDRED Ic_Ml
203738	Post Oak Bend Ic_Ml
203746	MILLSAP Ic_Ml
203850	Fort Worth Ic_Ml
203854	HALTOM CITY Ic_Ml
203855	Kennedale Ic_Ml
203857	Lake Worth Village Ic_Ml
203858	North Richland Hills Ic_Ml
203911	Dallas Ic_Ml
204001	Alvarado Oc_Ml
204002	Baird Oc_Ml
204003	Bardwell Oc_Ml
204004	Paris Oc_Ml
204005	Bonham Oc_Ml
204006	Brownwood Oc_Ml
204007	Gainesville Oc_Ml
204008	Burleson Oc_Ml
204009	Caddo Mills Oc_Ml
204010	Carrollton Oc_Ml
204012	Celina Oc_Ml
204013	Chillicothe Oc_Ml
204014	Clyde Oc_Ml
204015	Commerce Oc_Ml
204017	Cumby Oc_Ml
204018	Electra Oc_Ml

Service Area	Description
204019	Oakwood Oc_MI
204020	Emhouse Oc_MI
204022	Farmersville Oc_MI
204023	Ferris Oc_MI
204024	Forney Oc_MI
204025	Forreston Unincorp_Oc_MI
204026	Frisco Oc_MI
204027	Garland Oc_MI
204028	GRANDVIEWOc_MI
204029	Greenville Oc_MI
204031	Boyd Oc_MI
204032	Henrietta Oc_MI
204033	Honey Grove Oc_MI
204034	Hutchins Oc_MI
204036	Italy Oc_MI
204037	Itasca Oc_MI
204038	Josephine Oc_MI
204039	Joshua Oc_MI
204040	Kaufman Oc_MI
204041	Keene Oc_MI
204042	Lancaster Oc_MI
204043	Lewisville Oc_MI
204045	Mansfield Oc_MI
204046	Maypearl Oc_MI
204047	Mesquite Oc_MI
204048	Mexia Oc_MI
204049	Midlothian Oc_MI
204050	Moran Oc_MI
204051	Nevada Oc_MI
204053	Plano Oc_MI
204054	Prosper_Oc_MI
204055	Putnam Oc_MI
204056	Rhome Oc_MI
204057	Richardson Oc_MI
204059	Rockwall Oc_MI
204061	Royse City Oc_MI
204062	Sanger Oc_MI
204063	Terrell Oc_MI
204064	Valley View (Cooke Cnty)Oc_MI
204065	Venus Oc_MI
204066	Vernon Oc_MI
204067	West Oc_MI
204068	Wortham Oc_MI
204069	Sulphur Springs Oc_MI
204070	Trenton Oc_MI
204071	Ector Oc_MI
204072	Dodd City Oc_MI
204073	Whitewright Oc_MI
204074	Anna Oc_MI
204075	Abbott Oc_MI
204076	Blooming Grove Oc_MI
204077	Bells Oc_MI
204078	Belton Oc_MI
204079	Cooper Oc_MI
204080	Campbell Oc_MI
204081	CELESTE_Oc_MI
204083	Frost Oc_MI
204084	Ladonia Oc_MI
204085	Leonard Oc_MI
204086	Marlin Oc_MI
204087	Mart Oc_MI
204088	Penelope Oc_MI
204089	Savoy Oc_MI
204090	Van Alstyne Oc_MI
204091	Wolfe City Oc_MI
204093	Temple Oc_MI
204094	Winters Oc_MI
204095	Ballinger Oc_MI
204097	Sweetwater Oc_MI
204098	Merkel Oc_MI
204099	Trent Oc_MI
204100	Dawson Oc_MI
204101	Roscoe Oc_MI
204102	Talpa (Unincorporated)_Oc_MI
204103	Colorado City Oc_MI
204104	Loraine Oc_MI
204105	Hubbard Oc_MI
204106	Malone Oc_MI
204107	Coolidge Oc_MI
204108	Bryan OC_MI
204109	Troy Oc_MI
204110	Lorena Oc_MI
204111	College Station Oc_MI
204112	Fate Oc_MI
204113	Brucevile-Eddy Oc_MI
204114	Windom Oc_MI
204115	Jewett Oc_MI
204116	Moody Oc_MI
204117	Hearne Oc_MI
204118	REAGAN_Oc_MI
204119	Mcgregor Oc_MI
204123	Aubrey Oc_MI
204124	Collinsville Oc_MI

Service Area	Description
204125	Pilot Point Oc_MI
204147	Allen Oc_MI
204148	Streetman Oc_MI
204155	Seymour Oc_MI
204156	Benjamin Oc_MI
204158	Munday Oc_MI
204161	Knox City Oc_MI
204163	Weinert Oc_MI
204164	Rochester Oc_MI
204165	Rule Oc_MI
204166	Haskell Oc_MI
204167	Elm Mott Oc_MI
204168	Stamford Oc_MI
204169	Hamlin_Oc_MI
204170	Arlington Oc_MI
204171	Rotan Oc_MI
204172	Roby Oc_MI
204173	Anson Oc_MI
204174	Sunset Oc_MI
204175	Bowie Oc_MI
204176	Bridgeport Oc_MI
204177	Bellevue Oc_MI
204178	Alvord Oc_MI
204179	Decatur Oc_MI
204180	Cleburne Oc_MI
204181	Corsicana Oc_MI
204182	Denton Oc_MI
204183	Denison Oc_MI
204184	Ennis Oc_MI
204185	Hillsboro Oc_MI
204186	McKinney Oc_MI
204187	Sherman Oc_MI
204188	Whitesboro Oc_MI
204189	Byers Oc_MI
204190	Iowa Park Oc_MI
204192	Petrolia Oc_MI
204193	Waxahachie Oc_MI
204194	Odell (Unincorporated)_Oc_MI
204195	Bangs Oc_MI
204196	Centerville Oc_MI
204197	Normangee Oc_MI
204198	Madisonville Oc_MI
204199	Hico Oc_MI
204200	Tioga Oc_MI
204201	Gatesville Oc_MI
204202	Oglesby Oc_MI
204204	Riesel Oc_MI
204205	Albany Oc_MI
204206	Brookston Unincorp_Oc_MI
204208	Godley Oc_MI
204209	Petty (Unincorporated)_Oc_MI
204210	MONTAGUEOc_MI
204211	Roxton Oc_MI
204212	Teague Oc_MI
204213	Bremond Oc_MI
204214	Snyder Oc_MI
204215	Wilmer Oc_MI
204216	Chandler Oc_MI
204217	Novice Oc_MI
204218	Santo Oc_MI AN
204219	Buckholts Oc_MI
204220	Holland Oc_MI
204221	Bartlett Oc_MI
204222	Rogers Oc_MI
204223	Rockdale Oc_MI
204224	Cameron Oc_MI
204225	Granger Oc_MI
204226	Georgetown Oc_MI
204227	Taylor Oc_MI
204228	Saginaw Oc_MI
204229	Newark Oc_MI
204230	Milford Oc_MI
204231	Palmer Oc_MI
204232	Round Rock Oc_MI
204234	Hutto Oc_MI
204235	Little River Acad Oc_MI
204236	Kerens Oc_MI
204237	Groesbeck Oc_MI
204238	Eastland Oc_MI
204239	Powell_Oc_MI
204240	Barry Oc_MI
204241	Wylie Oc_MI
204242	Lindsay Oc_MI
204243	Muenster Oc_MI
204245	Saint Jo Oc_MI
204246	Howe Oc_MI
204248	Whitney Oc_MI
204249	Granbury Oc_MI
204250	Ravenna Oc_MI
204251	Brownsboro Oc_MI
204252	Glen Rose Oc_MI
204253	Meridian Oc_MI
204254	Morgan Oc_MI

Service Area	Description
204255	Walnut Springs Oc_MI
204256	Clifton Oc_MI
204257	Clarksville Oc_MI
204259	Detroit Oc_MI
204260	Hamilton Oc_MI
204261	Valley Mills Oc_MI
204262	Crandall Oc_MI
204263	Seagoville Oc_MI
204264	Mabank Oc_MI
204265	Kemp Oc_MI
204266	Athens Oc_MI
204267	Strawn Oc_MI
204271	Gordon Oc_MI
204273	Lott Oc_MI
204274	Malakoff Oc_MI
204275	Rosebud Oc_MI
204276	Blossom Oc_MI
204277	Pecan Gap (Fannin Cnty) Oc_MI
204278	Chico Oc_MI
204279	Chilton (Unincorporated)_Oc_MI
204281	Scurry_Oc_MI
204283	Iredell Oc_MI
204284	Melissa Oc_MI
204286	Tuscola Oc_MI
204287	Lawn Oc_MI
204289	Caldwell Oc_MI
204290	Killeen Oc_MI
204291	Eustace Oc_MI
204292	Cisco Oc_MI
204294	Pottsboro Oc_MI
204295	Bogata Oc_MI
204296	Thorndale Oc_MI
204297	Buffalo Oc_MI
204300	Fairfield Oc_MI
204302	Kerrville Oc_MI
204303	Lueders Oc_MI
204304	Fredericksburg Oc_MI
204305	Llano Oc_MI
204306	San Saba Oc_MI
204307	Burnet Oc_MI
204308	Lampasas Oc_MI
204309	Marble Falls Oc_MI
204310	Goldthwaite Oc_MI
204311	Lometa Oc_MI
204312	Bertram Oc_MI
204313	Quitman Oc_MI
204317	Como Oc_MI
204318	Canton Oc_MI
204319	Red Oak Oc_MI
204324	HERMLEIGH_Oc_ML
204327	O'Brien Oc_MI
204329	Justin Oc_MI
204330	Roanoke Oc_MI
204331	Lipan Oc_MI
204332	Thornton Oc_MI
204333	Center Point Oc_MI
204334	Franklin Oc_MI
204335	Bandera Oc_MI
204339	Springtown Oc_MI
204340	Comfort (Unincorporated)_Oc_MI
204341	Blackwell Oc_MI
204343	Burkburnett Oc_MI
204344	Childress Oc_MI
204345	Dodson Oc_MI
204346	Jean Oc_MI
204347	Kirkland_Oc_MI
204348	Memphis Oc_MI
204349	Newcastle Oc_MI
204352	Quanah Oc_MI
204353	Wellington Oc_MI
204354	Palestine Oc_MI
204355	Lakeview Oc_MI
204358	Kamay (Unincorporated)_Oc_MI
204359	Azle Oc_MI
204360	Tyler Oc_MI
204361	Whitehouse Oc_MI
204362	Austin Oc_MI
204364	Sonora Oc_MI
204366	Blanket Oc_MI
204367	May (Unincorporated)_Oc_MI
204368	North Zulch Unincorp_Oc_MI
204369	Sadler Oc_MI
204370	Hawley Oc_MI
204371	Hewitt Oc_MI
204374	Tye Oc_MI
204375	Ranger Oc_MI
204378	Vera Oc_MI
204379	ROBINSON Oc_MI
204382	Early Oc_MI
204384	Murchison Oc_MI
204385	Gunter Oc_MI
204388	Sunnyvale Oc_MI
204392	Wells Branch Unicorp_Oc_MI

Service Area	Description
204394	Nocona Oc_MI
204397	Sachse Oc_MI
204398	Coppell Oc_MI
204399	Frankston Oc_MI
204400	Abilene Oc_MI
204401	Blue Ridge_Oc_MI
204402	Princeton Oc_MI
204404	Alba Oc_MI
204405	Point Oc_MI
204407	Quinlan Oc_MI
204408	Emory Oc_MI
204409	Crowley Oc_MI
204412	Harker Heights Oc_MI
204413	Poynor_Oc_MI
204415	Krum Oc_MI
204416	Ponder Oc_MI
204417	Chapel Hill Oc_MI
204420	Elmo_Oc_MI
204421	Tom Bean Oc_MI
204423	Robert Lee Oc_MI
204424	Trumbull_Oc_MI
204425	Reese Oc_MI
204427	Kosse Oc_MI
204429	Yantis Oc_MI
204431	Rio Vista_Oc_MI
204432	Paradise Oc_MI
204433	Bristol Unincorporated_Oc_MI
204434	Edom Oc_MI_Oc_MI
204435	BEN WHEELER_Oc_MI
204436	Lexington Oc_MI
204437	Crawford Oc_MI
204439	Cayuga Oc_MI
204440	Flower Mound Oc_MI
204442	Manor Oc_MI
204443	Pflugerville Oc_MI
204446	Argyle Oc_MI
204448	Northcrest Oc_MI
204449	Johntown Unincorporated_Oc_MI
204451	Stephenville Oc_MI
204452	Comanche Oc_MI
204453	Dublin Oc_MI
204454	De Leon Oc_MI
204456	Coleman Oc_MI
204457	Santa Anna Oc_MI
204458	Carbon Oc_MI
204459	Desdemona Unincorp_Oc_MI
204460	Gorman Oc_MI
204461	Reno - Lamar Co Oc_MI
204463	Annona Oc_MI
204464	Avery Oc_MI
204466	Southmayd Oc_MI
204469	Evant Oc_MI
204471	Paducah Oc_MI
204472	Carey (Unincorporated)_Oc_MI
204473	Tell (Unincorporated)_Oc_MI
204474	Newlin (Unincorporated)_Oc_MI
204475	Estelline Oc_MI
204476	Goodlet (Unincorporated)_Oc_MI
204480	Rice Oc_MI
204481	Star Harbor Oc_MI
204482	Somerville Oc_MI
204483	Lavon Oc_MI
204487	Heath Oc_MI
204493	Paint Rock Oc_MI
204497	SALTILLO_Oc_MI
204498	Little Elm Oc_MI
204500	San Angelo Oc_MI
204501	Avoca Oc_MI
204502	Miles Oc_MI
204503	Rowena (Unincorporated)_Oc_MI
204504	Bronte Oc_MI
204505	Archer City Oc_MI
204506	Clarendon Oc_MI
204507	Hedley Oc_MI
204508	Holliday Oc_MI
204509	Megargel Oc_MI
204510	Olney Oc_MI
204511	Toco Oc_MI
204512	Angus Oc_MI
204513	Ross Oc_MI
204514	Cedar Park Oc_MI
204516	Grayson Cty Ind Park_Oc_MI
204519	Cross Roads Oc_MI
204521	Reno - Parker Co Oc_MI
204523	Brushy Creek Unincorp_Oc_MI
204527	Mccaulley Unincorp_Oc_MI
204536	Longview (Gregg Cnty) Oc_MI
204538	Rolling Meadows Oc_MI
204580	Mambrino Oc_MI
204600	Wichita Falls_Wichita Cy_Oc_MI
204698	Wixon Valley_Oc_MI
204700	Waco Oc_MI
204705	ARTHUR CITY Oc_MI

Service Area	Description
204707	CROWELL Oc_MI
204709	EDDY Oc_MI
204710	EDGEWOOD Oc_MI
204711	FLINT Oc_MI
204713	GRAPELAND Oc_MI
204714	JACKSONVILLE Oc_MI
204715	KILGORE Oc_MI
204716	HENDERSON Oc_MI
204717	ELKHART Oc_MI
204718	OVALO Oc_MI
204719	OVERTON Oc_MI
204720	POWDERLY Oc_MI
204722	VALLEY VIEW Oc_MI
204723	WILLS POINT Oc_MI
204725	BAGWELL Oc_MI
204726	CUNEY Oc_MI
204727	DUNN Oc_MI
204729	HEIDENHEIMER Oc_MI
204730	KLONDIKE Oc_MI
204735	MILDRED Oc_MI
204738	Post Oak Bend Oc_MI
204739	Winnsboro Oc_MI
204740	IOLA_MI_Oc
204741	APR_MI_Oc
204742	Weatherford Oc_MI
204746	Millsap_Oc_MI
204800	Right of Way
204806	SOMMERVILLE GC101
204807	SOMMERVILLE GC102
204810	CENTRAL
204820	Sommerville_Gulf Cst_Oc_MI_R&C
204821	Manor_Gulf Coast Environs
204822	College Sta_Gulf Coast Env_R&C
204850	Fort Worth Oc_MI
204851	Benbrook Oc_MI
204855	Kennedale Oc_MI
204856	Lakeside Village Oc_MI
204857	Lake Worth Village Oc_MI
204858	North Richland Hills Oc_MI
204867	Rendon Oc_MI
205001	Alvarado Other_Ic_TP
205002	Baird Ic_Other_Tp
205004	PARIS_Other Ic_Tp
205006	Brownwood_Other_Ic_Tp
205008	Burleson_Other Ic_Tp
205010	Carrollton_Other Ic_Tp
205011	Cedar Hill_Other Ic_Tp
205014	Clyde Ic_Other_Tp
205020	Emhouse Other Ic Tp
205021	Everman_Other Ic_Tp
205026	Frisco_Other_Ic_Tp
205027	Garland_Other Ic_Tp
205028	Grandview Other_Ic_TP
205029	Greenville Other Ic_Tp
205034	Hutchins_Other IC_TP
205035	Irving_Other_Ic_Tp
205036	Italy Other_Ic_TP
205037	ITASCA_Other Ic_Tp
205042	Lancaster_Other Ic_Tp
205043	LEWISVILLE_Other Ic_Tp
205044	Beverly Hills_Other Ic_Tp
205045	Mansfield_Other Ic_Tp
205046	Maypearl Other_Oc_TP
205047	Mesquite_Other Ic_Tp
205048	Mexia Other Ic_Tp
205049	Midlothian_Other_Ic_TP
205051	NEVADA_Other Ic_Tp
205053	Plano_Other Ic_Tp
205054	Prosper_Other Ic_TP
205056	Rhome_Other Ic_Tp
205057	Richardson_Other_ Ic_Tp
205060	Rowlett_Other Ic_Tp
205070	Trenton_Other Ic_Tp
205073	Whitewright_Other Ic_Tp
205074	Anna_Other Ic_Tp
205075	Abbott Other Ic_Tp
205083	Frost Other Ic_Tp
205084	LADONIA_Other Ic_Tp
205086	MARLIN_Other Ic_Tp
205088	Penelope Other Ic_Tp
205089	Savoy_Other Ic_Tp
205092	Westminster_Other Ic_Tp
205100	Dawson Other Ic_Tp
205106	Malone Other Ic_Tp
205107	Coolidge Other Ic_Tp
205111	College Station_Other Ic_Tp
205112	Fate_Other Ic_Tp
205122	Duncanville_Other Ic_Tp
205123	Aubrey_Other Ic TP
205147	Allen_Other Ic_Tp
205152	Aurora_Other Ic_Tp
205156	Benjamin_Other_Ic_Tp
205158	Munday_Other_Ic_Tp

Service Area	Description
205159	Goree_Other_Ic_Tp
205160	Grand Prairie_Other Ic_Tp
205161	KNOX CITY_Other Ic_Tp
205162	Lacy-Lakeview_Other Ic_Tp
205163	Weinert_Other_Ic_Tp
205164	Rochester_Other_Ic_Tp
205165	Rule_Other_Ic_Tp
205166	Haskell_Other_Ic_Tp
205170	Arlington_Other_Ic_Tp
205173	Anson_Other_Ic_Tp
205176	BRIDGEPORT_OTHER Ic_Tp
205182	DENTON_Other Ic_Tp
205183	Denison_Other_ Ic_Tp
205186	McKinney_Other Ic_Tp
205187	Sherman_Other Ic_Tp
205190	IOWA PARK_Other Ic_Tp
205191	Garrett_Other Ic_Tp
205193	WAXAHACHIE_Other Ic_Tp
205200	Tioga_Other_Ic_Tp
205201	GATESVILLE_Other Ic_Tp
205207	Dalworthington Gardens_Other Ic_Tp
205208	Godley_Other_Ic_Tp
205215	Wilmer_Other_Ic_Tp
205217	Novice Other Ic TP
205219	Buckholts_Other_Ic_Tp
205222	Rogers_Other_Ic_Tp
205223	Rockdale_Other Ic_Tp
205226	Georgetown_Other Ic_Tp
205227	TAYLOR_Other Ic_Tp
205228	Saginaw-Other Ic_Tp
205229	Newark_Other_Ic_Tp
205230	Milfor Other_Ic_TP
205233	Bellmead_Other Ic_Tp
205234	Hutto_Other Ic_Tp
205236	KERENS_Other Ic_Tp
205237	GROESBECK_Other Ic_Tp
205240	Barry Other Ic_Tp
205241	Wylie_Other Ic_Tp
205242	Lindsay_Other_Ic_Tp
205243	Muenster_Other_Ic_Tp
205245	Saint Jo_Other_ Ic_Tp
205246	Howe_Other Ic_Tp
205247	Grapevine_Other_Ic_Tp
205251	BROWNSBORO_Other Ic_Tp
205263	Seagoville_Other Ic_Tp
205265	Kemp_Other IC_TP
205273	Lott_Other Ic_Tp
205274	MALAKOFF_Other Ic_Tp
205281	Scurry_Other IC_TP
205284	Melissa_Other-Ic_Tp
205285	Buffalo Gap Other Ic_TP
205287	Lawn Other Ic_Tp
205293	Farmers Branch_Other Ic_Tp
205294	Pottsboro Other_Ic_TP
205315	Euless_Other Ic_Tp
205316	Hurst_Other Ic_Tp
205317	COMO_Other Ic_Tp
205319	RED OAK_Other Ic_Tp
205320	De Soto_Other Ic_Tp
205327	O'Brien_Other_Ic_Tp
205328	Keller_Other_Ic_Tp
205329	Justin Other Ic_Tp
205330	Roanoke_Other IC_TP
205336	Lake Dallas_Other Ic_Tp
205337	Murphy_Other Ic_Tp
205338	Addison_Other Ic_Tp
205339	Springtown_Other Ic_Tp
205356	Pleasant Valley_Other Ic_Tp
205357	Sanctuary_Other_Ic_Tp
205359	Azle_Other Ic_Tp
205360	TYLER_Other Ic_Tp
205362	Austin Other Ic_Tp
205363	Bedford_Other Ic_Tp
205366	Blanket_Other_Ic_Tp
205371	Hewitt_Other Ic_Tp
205373	Nolanville_Other Ic_Tp
205379	Robinson_Other Ic_Tp
205382	Early_Other_Ic_Tp
205386	Balch Springs_Other Ic_Tp
205388	Sunnyvale_Other_ Ic_Tp
205392	Wells Branch_Other Ic_TP
205395	Woodway_Other Ic_Tp
205397	Sachse_Other Ic_Tp
205398	Coppell_Other Ic_Tp
205399	FRANKSTON_Other Ic_Tp
205400	Abilene Other_Ic_TP
205404	Alba_Other_Ic_Tp
205405	POINT_Other Ic_Tp
205406	Lone Oak_Other_Ic_Tp
205409	Crowley_Other Ic_Tp
205411	Watauga_Other Ic_Tp
205412	Harker Heights_Other Ic_Tp
205415	Krum_Other Ic_Tp

Service Area	Description
205416	Ponder Ic Other Tp
205418	Colleyville_Other Ic_Tp
205419	Impact_Other Ic_Tp
205420	Elmo_Other Ic_Tp
205421	Tom Bean-Other Ic_Tp
205428	Shady Shores_Other Ic_Tp
205434	Edom_Other Ic_Tp
205435	BEN WHEELER_Other Ic_Tp
205440	Flower Mound_Other Ic_Tp
205441	Highland Village_Other Ic_Tp
205443	Pflugerville_Other Ic_Tp
205448	Northcrest_Other Ic_Tp
205452	Comanche_IC_TP
205453	Dublin_IC_TP
205454	De Leon_IC_TP
205456	COLEMAN_Other Ic_Tp
205458	Carbon_IC_TP
205461	Reno - Lamar Co Other_Ic_Tp
205469	Evant_Other_Ic_Tp
205477	Pantego_Other Ic_Tp
205478	Westlake_Other Ic_Tp
205483	Lavon_Other Ic_Tp
205485	Fairview_Other Ic_Tp
205486	Hickory Creek_Other Ic_Tp
205487	Heath_Other Ic_Tp
205488	Haslet_Other Ic_Tp
205489	Southlake_Other Ic_Tp
205490	Oak Leaf_Other IC_TP
205494	Glenn Heights_Other Ic_Tp
205495	Retreat_Other Ic_Ml
205498	Little Elm_Other_Ic_Tp
205514	Cedar Park_Other Ic_Tp
205515	THE COLONY_Other Ic_Tp
205519	Cross Roads_Other IC_TP
205521	Reno_Other Ic_Tp
205524	Corinth_Other Ic_Tp
205525	Leander_Other Ic_Tp
205526	Goodlow_Other Ic_Tp
205528	Marshall Creek_Other IC_TP
205531	Lincoln Park_Other Ic_Tp
205532	Knollwood_Other Ic_Tp
205534	Northlake_Other Ic_Tp
205535	Corral City_Other Ic_Tp
205536	LONGVIEW_Other Ic_Tp
205545	Trophy Club_Other Ic_Tp
205546	Coppell Gas Lights Ic_Tp
205547	Iowa Park Gas Lights Ic_Tp
205596	Cashion Community_Other_Ic_Tp
205600	Wichita Falls_Other Ic_Tp
205617	Ovilla _ Other Ic_Tp
205630	Talty_Other Ic_TP
205638	Double Oak_Other Ic_Tp
205639	Parker_Other Ic_Tp
205640	Bartonville_Other IC TP
205644	Copper Canyon_Other Ic_Tp
205700	Waco_Other Ic_Tp
205704	Brazos Bend_Other Ic_Tp
205706	BRUCEVILLE_Other Ic_Tp
205708	DEL VALLE_Other Ic_Tp
205709	EDDY_Other Ic_Tp
205718	Ovalo Other Ic Tp
205720	Powderly_Other Ic_Tp
205721	SHEPPARD AFB_Other Ic_Tp
205722	VALLEY VIEW_Other Ic_Tp
205724	PORT ARTHUR_Other Ic_Tp
205726	CUNEY_Other Ic_Tp
205728	FLORENCE_Other Ic_Tp
205731	MERTENS_Other Ic_Tp
205732	NAVAL AIR STATION/ JRB_Other Ic_Tp
205733	TURKEY_Other Ic_Tp
205735	MILDRED_Other Ic_Tp
205736	ALEDO_Other Ic_Tp
205743	McLendon-Chisholm_Other Ic_Tp
205744	Coyote Flats_IC_TP
205745	HEBRON_Other Ic_TP
205850	Fort Worth_Other Ic_Tp
205851	Benbrook_Other Ic_Tp
205852	Edgecliff Village_Other Ic_Tp
205853	Forest Hill_Other Ic_Tp
205854	Haltom City_Other Ic_Tp
205855	Kennedale_Other Ic_Tp
205856	Lakeside Village_Other Ic_Tp
205857	Lake Worth_Other Ic_Tp
205858	N Richland Hills_Other Ic_Tp
205859	Richland Hills_Other Ic_Tp
205860	River Oaks_Other Ic_Tp
205861	Sansom Park_Other Ic_Tp
205862	Westover Hills_Other Ic_Tp
205863	Westworth Village_Other Ic_Tp
205864	White Settlement_Other Ic_Tp
205865	Blue Mound_Other Ic_Tp
205911	Dallas_Other Ic_Tp
205912	Highland Park_Other Ic_Tp

Service Area	Description
205913	University Park_Other Ic_Tp
205914	Cockrell Hill_Other Ic_Tp
205989	Lines C & D_Other
206001	Alvarado Oc_Other_Tp
206002	Baird Oc_Other_Tp
206006	BROWNWOOD_Other Oc_Tp
206008	Burleson_Other Oc_Tp
206010	Carrollton_Other Oc_Tp
206011	Cedar Hill_Other Oc_Tp
206014	Clyde Oc_Other_Tp
206018	ELECTRA_Other_Oc_Tp
206020	Emhouse Other Oc Tp
206021	Everman_Other Oc_Tp
206023	FERRIS_Other Oc_Tp
206025	Forreston Other_Oc_TP
206026	Frisco_Other Oc_Tp
206027	GARLAND_Other Oc_Tp
206028	Grandview Other_Oc_TP
206031	Boyd_Other Oc_Tp
206034	Hutchins_Other Oc_Tp
206035	Irving_Other Oc_Tp
206036	Italy Other_Oc_TP
206037	ITASCA_Other Oc_Tp
206039	Joshua_Other Oc_Tp
206040	Kaufman Oc_Other_Tp
206042	Lancaster_Other Oc_Tp
206045	Mansfield_Other Oc_Tp
206046	Maypearl Other_Oc_TP
206047	Mesquite_Other Oc_Tp
206048	Mexia_Other Oc_Tp
206049	Midlothian_Other_Oc_TP
206053	Plano_Other Oc_Tp
206054	Prosper_Other Oc_TP
206056	Rhome_Other Oc_Tp
206057	Richardson_Other Oc_Tp
206060	Rowlett_Other Oc_Tp
206063	Terrell_Other_Oc_Tp
206070	Trenton_Other Oc_Tp
206073	Whitewright_Other Oc_Tp
206074	Anna_Other Oc_Tp
206075	Abbott Other Oc_Tp
206083	Frost Other Oc_Tp
206088	Penelope Other Oc_Tp
206089	Savoy Other Oc_Tp
206092	WESTMINISTER_Other Oc_Tp
206098	Merkel_Other_Oc_Tp
206100	Dawson Other Oc_Tp
206106	Malone Other Oc_Tp
206107	Coolidge Other Oc_Tp
206111	College Station_Other Oc_Tp
206113	Bruceville-Eddy_Other Oc_Tp
206123	Aubrey_Other Oc_TP
206147	Allen_Other Oc_Tp
206155	SEYMOUR_Other Oc_Tp
206156	Benjamin_Other_Oc_Tp
206158	MUNDAY_Other Oc_Tp
206159	Goree_Other_Oc_Tp
206160	GRAND PRAIRIE_Other Oc_Tp
206161	Knox City_Other_Oc_Tp
206163	Weinert_Other_Oc_Tp
206164	Rochester_Other_Oc_Tp
206165	Rule_Other_Oc_Tp
206166	Haskell_Other_Oc_Tp
206168	Stamford_Other Oc_Tp
206169	HAMLIN_Other Oc_Tp
206170	Arlington_Other Oc_Tp
206173	Anson_Other Oc_Tp
206176	BRIDGEPORT_Other Oc_Tp
206180	Cleburne_Other Oc_Tp
206183	DENISON_Other Oc_Tp
206184	ENNIS_Other Oc_Tp
206186	McKinney_Other Oc_Tp
206187	SHERMAN_Other Oc_Tp
206190	IOWA PARK_Other Oc_Tp
206200	Tioga_Other Oc_Tp
206201	GATESVILLE_Other Oc_Tp
206208	Godley_Other_Oc_Tp
206212	TEAGUE_Other Oc_Tp
206215	Wilmer_Other OC_TP
206217	Novice Other Oc TP
206219	Buckholts_Other OC_TP
206222	Rogers_Other Oc_Tp
206223	Rockdale_Other_Oc_Tp
206226	Georgetown_Other Oc_Tp
206228	Saginaw_Other Oc_Tp
206229	Newark_Other Oc_Tp
206230	Milford Other_Oc_TP
206232	Hutto_Other Oc_Tp
206233	Bellmead_Other Oc_Tp
206234	Hutto_Other Oc_Tp
206240	Barry Other Oc_Tp
206241	Wylie_Other Oc_Tp
206242	Lindsay_Other_Oc_Tp

Service Area	Description
206243	Muenster_Other_Oc_Tp
206244	Myra_Other_Oc_Tp
206245	Saint Jo_Other Oc_Tp
206246	Howe-Van_Other Oc_Tp
206251	BROWNSBORO_Other Oc_Tp
206254	MORGAN_Other Oc_Tp
206257	CLARKSVILLE_Other Oc_Tp
206263	Seagoville_Other Oc_Tp
206265	Kemp_Other Oc_Tp
206266	ATHENS_Other Oc_Tp
206273	LOTT_Other Oc_Tp
206274	MALAKOFF_Other Oc_Tp
206281	Scurry_Other Oc_Tp
206284	Melissa_Other Oc_Tp
206285	Buffalo Gap Other Oc_TP
206287	Lawn Other Oc_Tp
206294	Pottsboro Oc_Other_Tp
206295	BOGATA_Other Oc_Tp
206304	Fredericksburg_ Other Oc_Tp
206315	Euless_Other Oc_Tp
206317	COMO_Other Oc_Tp
206319	RED OAK_Other Oc_Tp
206320	De Soto_Other Oc_Tp
206327	O'Brien_Other_Oc_Tp
206328	Keller_Other Oc_Tp
206329	Justin_Other Oc_Tp
206330	Roanoke_Other Oc_Tp
206336	Lake Dallas_Other Oc_Tp
206339	Springtown_Other Oc_Tp
206343	BURKBURNETT_Other Oc_Tp
206344	CHILDRESS_Other Oc_Tp
206352	QUANAH_Other Oc_Tp
206356	Pleasant Valley_Other Oc_Tp
206357	Sanctuary_Other Oc_Tp
206359	Azle_Other Oc_Tp
206360	TYLER_Other Oc_Tp
206362	Austin_Other Ic_Tp
206366	Blanket_Other_Oc_Tp
206378	Vera_Other_Oc_Tp
206379	Robinson_Other Oc_Tp
206382	Early_Other_Oc_Tp
206383	Sylvester Other Oc Tp
206386	Balch Springs_Other Oc_Tp
206388	Sunnyvale_Other Oc_Tp
206391	Carlsbad Oc_Other_Tp
206392	Wells Branch_Other Oc_Tp
206397	Sachse_Other Oc_Tp
206398	Coppell_Other Oc_Tp
206400	Abilene Other_Oc_TP
206404	Alba_Other_Oc_Tp
206405	Point_Other_Oc_Tp
206406	Lone Oak_Other_Oc_Tp
206409	Crowley_Other Oc_Tp
206412	Harker Heights Other Oc Tp
206415	Krum_Other Oc_Tp
206416	Ponder Oc Other Tp
206421	Tom Bean_Other Oc_Tp
206434	Edom_Other Oc_Tp
206435	BEN WHEELER_Other Oc_Tp
206440	Flower Mound_Other Oc_Tp
206442	MANOR_Other Oc_Tp
206443	Pflugerville_Other Oc_Tp
206447	Red Springs_Other_Oc_Tp
206452	Comanche_OC_TP
206453	Dublin_OC_TP
206454	De Leon_OC_TP
206458	Carbon_OC_TP
206459	Desdemona_OC_TP
206461	Reno - Lamar Co Other_Oc_Tp
206469	Evant Oc_Other_Tp
206478	Westlake_Other Oc_Tp
206483	Lavon_Other Oc_Tp
206485	Fairview_Other Oc_Tp
206487	Heath_Other Oc_Tp
206488	Haslet_Other Oc_Tp
206489	Southlake_Other Oc_Tp
206492	Avalon Other_Oc_TP
206494	Glenn Heights_Other Oc-Tp
206498	Little Elm_Other_Oc_Tp
206510	OLNEY_Other Oc_Tp
206514	Cedar Park_Other Oc_Tp
206515	THE COLONY_Other Oc_Tp
206518	Travis_Other OC_TP
206519	Crossroads_Other OC_TP
206521	Reno_Parker Co_Other_Oc_Tp
206523	Brushy Creek_Other Oc_Tp
206524	Corinth_Other Oc_Tp
206525	Leander_Other Oc_Tp
206527	McCaulley_Other Oc_Tp
206529	Buttercup Creek_Other Oc_Tp
206531	Lincoln Park_Other Oc_Tp
206535	Corral City_Other Oc_Tp
206536	LONGVIEW_Other Oc_Tp

Service Area	Description
206600	WICHITA FALLS_Other Oc_Tp
206617	Ovilla_Other Oc_Tp
206630	Talty_Other Oc_TP
206644	Copper Canyon_Other Oc_Tp
206700	WACO_Other Oc_Tp
206705	ARTHUR CITY_Other Oc_Tp
206707	Crowell_Other Oc_Tp
206708	DEL VALLE_Other Oc_Tp
206712	GLADEWATER_Other Oc_Tp
206714	JACKSONVILLE_Other Oc_Tp
206715	KILGORE_Other Oc_Tp
206718	Ovolo Other Oc Tp
206720	POWDERLY_Other Oc_Tp
206734	WARING_Other Oc_Tp
206736	ALEDO_Other Oc_Tp
206739	Winnsboro_Other Oc_Tp
206743	McLendon-Chisholm_Other Oc_Tp
206850	Fort Worth_Other Oc_Tp
206851	Benbrook_Other Oc_Tp
206853	Forest Hill_Other Oc_Tp
206855	Kennedale_Other Oc_Tp
206856	Lakeside Village_Other Oc_Tp
206858	North Richland Hills_Other Oc_Tp
206867	Rendon_Other Oc_Tp
207001	ALVARADO lc
207002	BAIRD lc
207003	BARDWELL lc
207004	PARIS lc
207005	BONHAM lc
207006	BROWNWOOD lc
207007	GAINESVILLE lc
207008	BURLESON lc
207009	CADDO MILLS lc
207010	CARROLLTON lc
207011	CEDAR HILL lc
207012	CELINA lc
207013	CHILLICOTHE lc
207014	CLYDE lc
207015	COMMERCE lc
207016	COVINGTON lc
207017	CUMBY lc
207018	ELECTRA lc
207019	OAKWOOD lc
207020	EMHOUSE lc
207021	EVERMAN lc
207022	FARMERSVILLE lc
207023	FERRIS lc
207024	FORNEY lc
207025	FORRESTON lc
207026	FRISCO lc
207027	GARLAND lc
207028	GRANDVIEW lc
207029	GREENVILLE lc
207030	HARROLD lc
207031	BOYD lc
207032	HENRIETTA lc
207033	HONEY GROVE lc
207034	HUTCHINS lc
207035	IRVING lc
207036	ITALY lc
207037	ITASCA lc
207038	JOSEPHINE lc
207039	JOSHUA lc
207040	KAUFMAN lc
207041	KEENE lc
207042	LANCASTER lc
207043	LEWISVILLE lc
207044	BEVERLY HILLS lc
207045	MANSFIELD lc
207046	MAYPEARL lc
207047	MESQUITE lc
207048	MEXIA lc
207049	MIDLOTHIAN lc
207050	MORAN lc
207051	NEVADA lc
207052	OKLAUNION lc
207053	PLANO lc
207054	PROSPER lc
207055	PUTNAM lc
207056	RHOME lc
207057	RICHARDSON lc
207058	RICHLAND lc
207059	ROCKWALL lc
207060	ROWLETT lc
207061	ROYSE CITY lc
207062	SANGER lc
207063	TERRELL lc
207064	VALLEY VIEW-COOKE CO lc
207065	VENUS lc
207066	VERNON lc
207067	WEST lc
207068	WORTHAM lc
207069	SULPHUR SPRINGS lc

Service Area	Description
207070	TRENTON lc
207071	ECTOR lc
207072	DODD CITY lc
207073	WHITEWRIGHT lc
207074	ANNA lc
207075	ABBOTT lc
207076	BLOOMING GROVE lc
207077	BELLS lc
207078	BELTON lc
207079	COOPER lc
207080	CAMPBELL lc
207081	CELESTE lc
207082	FAIRLIE lc
207083	FROST lc
207084	LADONIA lc
207085	LEONARD lc
207086	MARLIN lc
207087	MART lc
207088	PENELOPE lc
207089	SAVOY lc
207090	VAN ALSTYNE lc
207091	WOLFE CITY lc
207092	WESTMINSTER lc
207093	TEMPLE lc
207094	WINTERS lc
207095	BALLINGER lc
207096	TRINIDAD lc
207097	SWEETWATER lc
207098	MERKEL lc
207099	TRENT lc
207100	DAWSON lc
207101	ROSCOE lc
207102	TALPA lc
207103	COLORADO CITY lc
207104	LORAINE lc
207105	HUBBARD lc
207106	MALONE lc
207107	COOLIDGE lc
207108	BRYAN lc
207109	TROY lc
207110	LORENA lc
207111	COLLEGE STATION lc
207112	FATE lc
207113	BRUCEVILLE-EDDY lc
207114	WINDOM lc
207115	JEWETT lc
207116	MOODY lc
207117	HEARNE lc
207118	REAGAN lc
207119	MCGREGOR lc
207120	LILLIAN lc
207122	DUNCANVILLE lc
207123	AUBREY lc
207124	COLLINSVILLE lc
207125	PILOT POINT lc
207147	ALLEN lc
207148	STREETMAN lc
207151	DEPORT lc
207152	AURORA lc
207153	ENLOE lc
207154	RHINELAND lc
207155	SEYMOUR lc
207156	BENJAMIN lc
207157	TRUSCOTT lc
207158	MUNDAY lc
207159	GOREE lc
207160	GRAND PRAIRIE lc
207161	KNOX CITY lc
207162	LACY LAKEVIEW lc
207163	WEINERT lc
207164	ROCHESTER lc
207165	RULE lc
207166	HASKELL lc
207167	ELM MOTT lc
207168	STAMFORD lc
207169	HAMLIN lc
207170	ARLINGTON lc
207171	ROTAN lc
207172	ROBY lc
207173	ANSON lc
207174	SUNSET lc
207175	BOWIE lc
207176	BRIDGEPORT lc
207177	BELLEVUE lc
207178	ALVORD lc
207179	DECATUR lc
207180	CLEBURNE lc
207181	CORSICANA lc
207182	DENTON lc
207183	DENISON lc
207184	ENNIS lc
207185	HILLSBORO lc
207186	MCKINNEY lc

Service Area	Description
207187	SHERMAN lc
207188	WHITESBORO lc
207189	BYERS lc
207190	IOWA PARK lc
207191	GARRETT lc
207192	PETROLIA lc
207193	WAXAHACHIE lc
207194	ODELL lc
207195	BANGS lc
207196	CENTERVILLE lc
207197	NORMANGEE lc
207198	MADISONVILLE lc
207199	HICO lc
207200	TIOGA lc
207201	GATESVILLE lc
207202	OGLESBY lc
207203	CALVERT lc
207204	RIESEL lc
207205	ALBANY lc
207206	BROOKSTON lc
207207	DALWORTHINGTON GARDN lc
207208	GODLEY lc
207209	PETTY lc
207210	MONTAGUE lc
207211	ROXTON lc
207212	TEAGUE lc
207213	BREMOND lc
207214	SNYDER lc
207215	WILMER lc
207216	CHANDLER lc
207217	NOVICE lc
207218	SANTO lc
207219	BUCKHOLTS lc
207220	HOLLAND lc
207221	BARTLETT lc
207222	ROGERS lc
207223	ROCKDALE lc
207224	CAMERON lc
207225	GRANGER lc
207226	GEORGETOWN lc
207227	TAYLOR lc
207228	SAGINAW lc
207229	NEWARK lc
207230	MILFORD lc
207231	PALMER lc
207232	ROUND ROCK lc
207233	BELLMEAD lc
207234	HUTTO lc
207235	LITTLE RIVER-ACADEMY lc
207236	KERENS lc
207237	GROESBECK lc
207238	EASTLAND lc
207239	POWELL lc
207240	BARRY lc
207241	WYLIE lc
207242	LINDSAY lc
207243	MUENSTER lc
207244	MYRA lc
207245	SAINT JO lc
207246	HOWE lc
207247	GRAPEVINE lc
207248	WHITNEY lc
207249	GRANBURY lc
207250	RAVENNA lc
207251	BROWNSBORO lc
207252	GLEN ROSE lc
207253	MERIDIAN lc
207254	MORGAN lc
207255	WALNUT SPRINGS lc
207256	CLIFTON lc
207257	CLARKSVILLE lc
207259	DETROIT lc
207260	HAMILTON lc
207261	VALLEY MILLS lc
207262	CRANDALL lc
207263	SEAGOVILLE lc
207264	MABANK lc
207265	KEMP lc
207266	ATHENS lc
207267	STRAWN lc
207271	GORDON lc
207272	VALERA lc
207273	LOTT lc
207274	MALAKOFF lc
207275	ROSEBUD lc
207276	BLOSSOM lc
207277	PECAN GAP lc
207278	CHICO lc
207279	CHILTON lc
207280	OSCEOLA lc
207281	SCURRY lc
207282	TEHUACANA lc
207283	IREDELL lc

Service Area	Description
207284	MELISSA lc
207285	BUFFALO GAP lc
207286	TUSCOLA lc
207287	LAWN lc
207289	CALDWELL lc
207290	KILLEEN lc
207291	EUSTACE lc
207292	CISCO lc
207293	FARMERS BRANCH lc
207294	POTTSBORO lc
207295	BOGATA lc
207296	THORNDALE lc
207297	BUFFALO lc
207298	THRALL lc
207300	FAIRFIELD lc
207302	KERRVILLE lc
207303	LUEDERS lc
207304	FREDERICKSBURG lc
207305	LLANO lc
207306	SAN SABA lc
207307	BURNET lc
207308	LAMPASAS lc
207309	MARBLE FALLS lc
207310	GOLDTHWAITE lc
207311	LOMETA lc
207312	BERTRAM lc
207313	QUITMAN lc
207315	EULESS lc
207316	HURST lc
207317	COMO lc
207318	CANTON lc
207319	RED OAK lc
207320	DESOTO lc
207324	HERMLEIGH lc
207325	BRASHEAR lc
207326	POTTSVILLE lc
207327	OBRIEN lc
207328	KELLER lc
207329	JUSTIN lc
207330	ROANOKE lc
207331	LIPAN lc
207332	THORNTON lc
207333	CENTER POINT lc
207334	FRANKLIN lc
207335	BANDERA lc
207336	LAKE DALLAS lc
207337	MURPHY lc
207338	ADDISON lc
207339	SPRINGTOWN lc
207340	COMFORT lc
207341	BLACKWELL lc
207343	BURKBURNETT lc
207344	CHILDRESS lc
207345	DODSON lc
207346	JEAN lc
207347	KIRKLAND lc
207348	MEMPHIS lc
207349	NEWCASTLE lc
207352	QUANAH lc
207353	WELLINGTON lc
207354	PALESTINE lc
207355	LAKEVIEW lc
207356	PLEASANT VALLEY lc
207357	SANCTUARY lc
207358	KAMAY lc
207359	AZLE lc
207360	TYLER lc
207361	WHITEHOUSE lc
207362	AUSTIN lc
207363	BEDFORD lc
207364	SONORA lc
207365	CHRISTOVAL lc
207366	BLANKET lc
207367	MAY lc
207368	NORTH ZULCH lc
207369	SADLER lc
207370	HAWLEY lc
207371	HEWITT lc
207372	COPPERAS COVE lc
207373	NOLANVILLE lc
207374	TYE lc
207375	RANGER lc
207376	OLDEN lc
207378	VERA lc
207379	ROBINSON lc
207381	STAR lc
207382	EARLY lc
207383	SYLVESTER lc
207384	MURCHISON lc
207385	GUNTER lc
207386	BALCH SPRINGS lc
207388	SUNNYVALE lc
207389	WINGATE lc

Service Area	Description
207391	CARLSBAD lc
207392	WELLS BRANCH lc
207394	NOCONA lc
207395	WOODWAY lc
207397	SACHSE lc
207398	COPPELL lc
207399	FRANKSTON lc
207400	ABILENE lc
207401	BLUE RIDGE lc
207402	PRINCETON lc
207404	ALBA lc
207405	POINT lc
207406	LONE OAK lc
207407	QUINLAN lc
207408	EMORY lc
207409	CROWLEY lc
207411	WATAUGA lc
207412	HARKER HEIGHTS lc
207413	POYNOR lc
207415	KRUM lc
207416	PONDER lc
207417	CHAPEL HILL lc
207418	COLLEYVILLE lc
207419	IMPACT lc
207420	ELMO lc
207421	TOM BEAN lc
207423	ROBERT LEE lc
207424	TRUMBALL lc
207425	REESE lc
207426	PICKTON lc
207427	KOSSE lc
207428	SHADY SHORES lc
207429	YANTIS lc
207430	BLUM lc
207431	RIO VISTA lc
207432	PARADISE lc
207433	BRISTOL lc
207434	EDOM lc
207435	BEN WHEELER lc
207436	LEXINGTON lc
207437	CRAWFORD lc
207439	CAYUGA lc
207440	FLOWER MOUND lc
207441	HIGHLAND VILLAGE lc
207442	MANOR lc
207443	PFLUGERVILLE lc
207444	MIDWAY lc
207446	ARGYLE lc
207447	RED SPRINGS lc
207448	NORTHCREST lc
207449	JOHNTOWN lc
207451	STEPHENVILLE lc
207452	COMANCHE lc
207453	DUBLIN lc
207454	DE LEON lc
207455	GUSTINE lc
207456	COLEMAN lc
207457	SANTA ANNA lc
207458	CARBON lc
207459	DESDEMONA lc
207460	GORMAN lc
207461	RENO (LAMAR CO) lc
207462	SOUTH MOUNTAIN lc
207463	ANNONA lc
207464	AVERY lc
207465	THROCKMORTON lc
207466	SOUTHMAYD lc
207467	RUNAWAY BAY lc
207468	EDEN lc
207469	EVANT lc
207471	PADUCAH lc
207472	CAREY lc
207473	TELL lc
207474	NEWLIN ENVIRON lc
207475	ESTELLINE lc
207476	GOODLETT lc
207477	PANTEGO lc
207478	WESTLAKE lc
207479	ALMA lc
207480	RICE lc
207481	STAR HARBOR lc
207482	SOMERVILLE lc
207483	LAVON lc
207485	FAIRVIEW (COLLIN) lc
207486	HICKORY CREEK lc
207487	HEATH lc
207488	HASLET lc
207489	SOUTHLAKE lc
207490	OAK LEAF lc
207492	AVALON lc
207493	PAINT ROCK lc
207494	GLENN HEIGHTS lc
207495	RETREAT lc

Service Area	Description
207496	LEONA lc
207497	SALTILLO lc
207498	LITTLE ELM lc
207500	SAN ANGELO lc
207501	AVOCA lc
207502	MILES lc
207503	ROWENA lc
207504	BRONTE lc
207505	ARCHER CITY lc
207506	CLARENDON lc
207507	HEDLEY lc
207508	HOLLIDAY lc
207509	MEGARGEL lc
207510	OLNEY lc
207511	TOCO lc
207512	ANGUS lc
207513	ROSS lc
207514	CEDAR PARK lc
207515	THE COLONY lc
207516	GRAYSON CO IND PK lc
207518	TRAVIS lc
207519	CROSS ROADS (DENTON) lc
207521	RENO(PARKER CO) lc
207522	SUN VALLEY lc
207523	BRUSHY CREEK lc
207524	CORINTH lc
207525	LEANDER lc
207526	GOODLOW lc
207527	MCCAULLEY lc
207528	MARSHALL CREEK lc
207529	BUTTERCUP CREEK lc
207531	LINCOLN PARK lc
207532	KNOLLWOOD lc
207533	PECAN HILL lc
207534	NORTHLAKE lc
207535	CORRAL CITY lc
207536	LONGVIEW lc
207537	LAKEPORT lc
207538	ROLLING MEADOWS lc
207539	BAMBURG lc
207540	SABINE lc
207541	LELIA LAKE lc
207542	MOBILE CITY lc
207543	SAMNORWOOD lc
207544	VALLEY VIEW(WICHITA) lc
207545	TROPHY CLUB lc
207546	COPPELL GAS LIGHTS lc
207547	IOWA PARK GAS LIGHTS lc
207560	LOFTIN lc
207580	MAMBRINO lc
207592	GILLILAND lc
207593	KURTEN lc
207596	CASHION COMMUNITY lc
207597	RIVER CREEK lc
207598	HORSESHOE lc
207599	PECANWAY lc
207600	WICHITA FALLS lc
207617	OVILLA lc
207630	TALTY lc
207638	DOUBLE OAK lc
207639	PARKER lc
207640	BARTONVILLE lc
207644	COPPER CANYON lc
207698	WIXON VALLEY lc
207700	WACO lc
207701	STONEY RIDGE lc
207702	UNION HILL lc
207703	CROSSROADS-HENDERSON lc
207704	BRAZOS BEND lc
207705	ARTHUR CITY_lc
207706	BRUCEVILLE_lc
207707	CROWELL_lc
207708	DEL VALLE_lc
207709	EDDY_lc
207710	EDGEWOOD_lc
207711	FLINT_lc
207712	GLADEWATER_lc
207713	GRAPELAND_lc
207714	JACKSONVILLE_lc
207715	KILGORE_lc
207716	HENDERSON_lc
207717	ELKHART_lc
207718	OVALO_lc
207719	OVERTON_lc
207720	POWDERLY_lc
207721	SHEPPARD AFB_lc
207722	VALLEY VIEW_lc
207723	WILLS POINT_lc
207724	PORT ARTHUR_lc
207725	BAGWELL_lc
207726	CUNEY_lc
207727	DUNN_lc
207728	FLORENCE_lc

Service Area	Description
207729	HEIDENHEIMER_Ic
207730	KLONDIKE_Ic
207731	MERTENS_Ic
207732	NAVAL AIR STATION/ JRB_Ic
207733	TURKEY_Ic
207734	WARING_Ic
207735	MILDRED_Ic
207736	ALEDO_Ic
207738	Post Oak Bend Oc
207740	IOLA_Ic
207741	APR_Ic
207743	McLendon-Chisholm_Ic
207744	Coyote Flats Ic
207745	HEBRON_Ic
207746	MILLSAP_Ic
207751	DEW Ic
207800	RIGHT OF WAY Ic
207806	SOMMERVILLE GC101 Ic
207807	SOMMERVILLE GC102 Ic
207810	CENTRAL Ic
207820	SOMMERVILLE GC107 Ic
207821	MANOR-GC Ic
207822	COLLEGE STATION-GC Ic
207850	FORT WORTH Ic
207851	BENBROOK Ic
207852	EDGECLIFF VILLAGE Ic
207853	FOREST HILL Ic
207854	HALTOM CITY Ic
207855	KENNEDALE Ic
207856	LAKESIDE Ic
207857	LAKE WORTH Ic
207858	NORTH RICHLAND HILLS Ic
207859	RICHLAND HILLS Ic
207860	RIVER OAKS Ic
207861	SANSOM PARK VILLAGE Ic
207862	WESTOVER HILLS Ic
207863	WESTWORTH VILLAGE Ic
207864	WHITE SETTLEMENT Ic
207865	BLUE MOUND Ic
207867	RENDON Ic
207911	DALLAS Ic
207912	HIGHLAND PARK Ic
207913	UNIVERSITY PARK Ic
207914	COCKRELL HILL Ic
208001	ALVARADO Oc
208002	BAIRD Oc
208003	BARDWELL Oc
208004	PARIS Oc
208005	BONHAM Oc
208006	BROWNWOOD Oc
208007	GAINESVILLE Oc
208008	BURLESON Oc
208009	CADDO MILLS Oc
208010	CARROLLTON Oc
208011	CEDAR HILL Oc
208012	CELINA Oc
208013	CHILLICOTHE Oc
208014	CLYDE Oc
208015	COMMERCE Oc
208016	COVINGTON Oc
208017	CUMBY Oc
208018	ELECTRA Oc
208019	OAKWOOD Oc
208020	EMHOUSE Oc
208021	EVERMAN Oc
208022	FARMERSVILLE Oc
208023	FERRIS Oc
208024	FORNEY Oc
208025	FORRESTON Oc
208026	FRISCO Oc
208027	GARLAND Oc
208028	GRANDVIEW Oc
208029	GREENVILLE Oc
208030	HARROLD Oc
208031	BOYD Oc
208032	HENRIETTA Oc
208033	HONEY GROVE Oc
208034	HUTCHINS Oc
208035	IRVING Oc
208036	ITALY Oc
208037	ITASCA Oc
208038	JOSEPHINE Oc
208039	JOSHUA Oc
208040	KAUFMAN Oc
208041	KEENE Oc
208042	LANCASTER Oc
208043	LEWISVILLE Oc
208044	BEVERLY HILLS Oc
208045	MANSFIELD Oc
208046	MAYPEARL Oc
208047	MESQUITE Oc
208048	MEXIA Oc
208049	MIDLOTHIAN Oc

Service Area	Description
208050	MORAN Oc
208051	NEVADA Oc
208052	OKLAUNION Oc
208053	PLANO Oc
208054	PROSPER Oc
208055	PUTNAM Oc
208056	RHOME Oc
208057	RICHARDSON Oc
208058	RICHLAND Oc
208059	ROCKWALL Oc
208060	ROWLETT Oc
208061	ROYSE CITY Oc
208062	SANGER Oc
208063	TERRELL Oc
208064	VALLEY VIEW-COOKE CO Oc
208065	VENUS Oc
208066	VERNON Oc
208067	WEST Oc
208068	WORTHAM Oc
208069	SULPHUR SPRINGS Oc
208070	TRENTON Oc
208071	ECTOR Oc
208072	DODD CITY Oc
208073	WHITEWRIGHT Oc
208074	ANNA Oc
208075	ABBOTT Oc
208076	BLOOMING GROVE Oc
208077	BELLS Oc
208078	BELTON Oc
208079	COOPER Oc
208080	CAMPBELL Oc
208081	CELESTE Oc
208082	FAIRLIE Oc
208083	FROST Oc
208084	LADONIA Oc
208085	LEONARD Oc
208086	MARLIN Oc
208087	MART Oc
208088	PENELOPE Oc
208089	SAVOY Oc
208090	VAN ALSTYNE Oc
208091	WOLFE CITY Oc
208092	WESTMINSTER Oc
208093	TEMPLE Oc
208094	WINTERS Oc
208095	BALLINGER Oc
208096	TRINIDAD Oc
208097	SWEETWATER Oc
208098	MERKEL Oc
208099	TRENT Oc
208100	DAWSON Oc
208101	ROSCOE Oc
208102	TALPA Oc
208103	COLORADO CITY Oc
208104	LORAINE Oc
208105	HUBBARD Oc
208106	MALONE Oc
208107	COOLIDGE Oc
208108	BRYAN Oc
208109	TROY Oc
208110	LORENA Oc
208111	COLLEGE STATION Oc
208112	FATE Oc
208113	BRUCEVILLE-EDDY Oc
208114	WINDOM Oc
208115	JEWETT Oc
208116	MOODY Oc
208117	HEARNE Oc
208118	REAGAN Oc
208119	MCGREGOR Oc
208120	LILLIAN Oc
208122	DUNCANVILLE Oc
208123	AUBREY Oc
208124	COLLINSVILLE Oc
208125	PILOT POINT Oc
208147	ALLEN Oc
208148	STREETMAN Oc
208151	DEPORT Oc
208152	AURORA Oc
208153	ENLOE Oc
208154	RHINELAND Oc
208155	SEYMOUR Oc
208156	BENJAMIN Oc
208157	TRUSCOTT Oc
208158	MUNDAY Oc
208159	GOREE Oc
208160	GRAND PRAIRIE Oc
208161	KNOX CITY Oc
208162	LACY LAKEVIEW Oc
208163	WEINERT Oc
208164	ROCHESTER Oc
208165	RULE Oc
208166	HASKELL Oc

Service Area	Description
208167	ELM MOTT Oc
208168	STAMFORD Oc
208169	HAMLIN Oc
208170	ARLINGTON Oc
208171	ROTAN Oc
208172	ROBY Oc
208173	ANSON Oc
208174	SUNSET Oc
208175	BOWIE Oc
208176	BRIDGEPORT Oc
208177	BELLEVUE Oc
208178	ALVORD Oc
208179	DECATUR Oc
208180	CLEBURNE Oc
208181	CORSICANA Oc
208182	DENTON Oc
208183	DENISON Oc
208184	ENNIS Oc
208185	HILLSBORO Oc
208186	MCKINNEY Oc
208187	SHERMAN Oc
208188	WHITESBORO Oc
208189	BYERS Oc
208190	IOWA PARK Oc
208191	GARRETT Oc
208192	PETROLIA Oc
208193	WAXAHACHIE Oc
208194	ODELL Oc
208195	BANGS Oc
208196	CENTERVILLE Oc
208197	NORMANGEE Oc
208198	MADISONVILLE Oc
208199	HICO Oc
208200	TIOGA Oc
208201	GATESVILLE Oc
208202	OGLESBY Oc
208203	CALVERT Oc
208204	RIESEL Oc
208205	ALBANY Oc
208206	BROOKSTON Oc
208207	DALWORTHINGTON GARDN Oc
208208	GODLEY Oc
208209	PETTY Oc
208210	MONTAGUE Oc
208211	ROXTON Oc
208212	TEAGUE Oc
208213	BREMOND Oc
208214	SNYDER Oc
208215	WILMER Oc
208216	CHANDLER Oc
208217	NOVICE Oc
208218	SANTO Oc
208219	BUCKHOLTS Oc
208220	HOLLAND Oc
208221	BARTLETT Oc
208222	ROGERS Oc
208223	ROCKDALE Oc
208224	CAMERON Oc
208225	GRANGER Oc
208226	GEORGETOWN Oc
208227	TAYLOR Oc
208228	SAGINAW Oc
208229	NEWARK Oc
208230	MILFORD Oc
208231	PALMER Oc
208232	ROUND ROCK Oc
208233	BELLMEAD Oc
208234	HUTTO Oc
208235	LITTLE RIVER-ACADEMY Oc
208236	KERENS Oc
208237	GROESBECK Oc
208238	EASTLAND Oc
208239	POWELL Oc
208240	BARRY Oc
208241	WYLIE Oc
208242	LINDSAY Oc
208243	MUENSTER Oc
208244	MYRA Oc
208245	SAINT JO Oc
208246	HOWE Oc
208247	GRAPEVINE Oc
208248	WHITNEY Oc
208249	GRANBURY Oc
208250	RAVENNA Oc
208251	BROWNSBORO Oc
208252	GLEN ROSE Oc
208253	MERIDIAN Oc
208254	MORGAN Oc
208255	WALNUT SPRINGS Oc
208256	CLIFTON Oc
208257	CLARKSVILLE Oc
208259	DETROIT Oc
208260	HAMILTON Oc

Service Area	Description
208261	VALLEY MILLS Oc
208262	CRANDALL Oc
208263	SEAGOVILLE Oc
208264	MABANK Oc
208265	KEMP Oc
208266	ATHENS Oc
208267	STRAWN Oc
208271	GORDON Oc
208272	VALERA Oc
208273	LOTT Oc
208274	MALAKOFF Oc
208275	ROSEBUD Oc
208276	BLOSSOM Oc
208277	PECAN GAP Oc
208278	CHICO Oc
208279	CHILTON Oc
208280	OSCEOLA Oc
208281	SCURRY Oc
208282	TEHUACANA Oc
208283	IREDELL Oc
208284	MELISSA Oc
208285	BUFFALO GAP Oc
208286	TUSCOLA Oc
208287	LAWN Oc
208289	CALDWELL Oc
208290	KILLEEN Oc
208291	EUSTACE Oc
208292	CISCO Oc
208293	FARMERS BRANCH Oc
208294	POTTSBORO Oc
208295	BOGATA Oc
208296	THORNDALE Oc
208297	BUFFALO Oc
208298	THRALL Oc
208300	FAIRFIELD Oc
208302	KERRVILLE Oc
208303	LUEDERS Oc
208304	FREDERICKSBURG Oc
208305	LLANO Oc
208306	SAN SABA Oc
208307	BURNET Oc
208308	LAMPASAS Oc
208309	MARBLE FALLS Oc
208310	GOLDTHWAITE Oc
208311	LOMETA Oc
208312	BERTRAM Oc
208313	QUITMAN Oc
208315	EULESS Oc
208316	HURST Oc
208317	COMO Oc
208318	CANTON Oc
208319	RED OAK Oc
208320	DESOTO Oc
208324	HERMLEIGH Oc
208325	BRASHEAR Oc
208326	POTTSVILLE Oc
208327	OBRIEN Oc
208328	KELLER Oc
208329	JUSTIN Oc
208330	ROANOKE Oc
208331	LIPAN Oc
208332	THORNTON Oc
208333	CENTER POINT Oc
208334	FRANKLIN Oc
208335	BANDERA Oc
208336	LAKE DALLAS Oc
208337	MURPHY Oc
208338	ADDISON Oc
208339	SPRINGTOWN Oc
208340	COMFORT Oc
208341	BLACKWELL Oc
208343	BURKBURNETT Oc
208344	CHILDRESS Oc
208345	DODSON Oc
208346	JEAN Oc
208347	KIRKLAND Oc
208348	MEMPHIS Oc
208349	NEWCASTLE Oc
208352	QUANAH Oc
208353	WELLINGTON Oc
208354	PALESTINE Oc
208355	LAKEVIEW Oc
208356	PLEASANT VALLEY Oc
208357	SANCTUARY Oc
208358	KAMAY Oc
208359	AZLE Oc
208360	TYLER Oc
208361	WHITEHOUSE Oc
208362	AUSTIN Oc
208363	BEDFORD Oc
208364	SONORA Oc
208365	CHRISTOVAL Oc
208366	BLANKET Oc

Service Area	Description
208367	MAY Oc
208368	NORTH ZULCH Oc
208369	SADLER Oc
208370	HAWLEY Oc
208371	HEWITT Oc
208372	COPPERAS COVE Oc
208373	NOLANVILLE Oc
208374	TYE Oc
208375	RANGER Oc
208376	OLDEN Oc
208378	VERA Oc
208379	ROBINSON Oc
208381	STAR Oc
208382	EARLY Oc
208383	SYLVESTER Oc
208384	MURCHISON Oc
208385	GUNTER Oc
208386	BALCH SPRINGS Oc
208388	SUNNYVALE Oc
208389	WINGATE Oc
208391	CARLSBAD Oc
208392	WELLS BRANCH Oc
208394	NOCONA Oc
208395	WOODWAY Oc
208397	SACHSE Oc
208398	COPPELL Oc
208399	FRANKSTON Oc
208400	ABILENE Oc
208401	BLUE RIDGE Oc
208402	PRINCETON Oc
208404	ALBA Oc
208405	POINT Oc
208406	LONE OAK Oc
208407	QUINLAN Oc
208408	EMORY Oc
208409	CROWLEY Oc
208411	WATAUGA Oc
208412	HARKER HEIGHTS Oc
208413	POYNOR Oc
208415	KRUM Oc
208416	PONDER Oc
208417	CHAPEL HILL Oc
208418	COLLEYVILLE Oc
208419	IMPACT Oc
208420	ELMO Oc
208421	TOM BEAN Oc
208423	ROBERT LEE Oc
208424	TRUMBALL Oc
208425	REESE Oc
208426	PICKTON Oc
208427	KOSSE Oc
208428	SHADY SHORES Oc
208429	YANTIS Oc
208430	BLUM Oc
208431	RIO VISTA Oc
208432	PARADISE Oc
208433	BRISTOL Oc
208434	EDOM Oc
208435	BEN WHEELER Oc
208436	LEXINGTON Oc
208437	CRAWFORD Oc
208439	CAYUGA Oc
208440	FLOWER MOUND Oc
208441	HIGHLAND VILLAGE Oc
208442	MANOR Oc
208443	PFLUGERVILLE Oc
208444	MIDWAY Oc
208446	ARGYLE Oc
208447	RED SPRINGS Oc
208448	NORTHCREST Oc
208449	JOHNTOWN Oc
208451	STEPHENVILLE Oc
208452	COMANCHE Oc
208453	DUBLIN Oc
208454	DE LEON Oc
208455	GUSTINE Oc
208456	COLEMAN Oc
208457	SANTA ANNA Oc
208458	CARBON Oc
208459	DESDEMONA Oc
208460	GORMAN Oc
208461	RENO (LAMAR CO) Oc
208462	SOUTH MOUNTAIN Oc
208463	ANNONA Oc
208464	AVERY Oc
208465	THROCKMORTON Oc
208466	SOUTHMAYD Oc
208467	RUNAWAY BAY Oc
208468	EDEN Oc
208469	EVANT Oc
208471	PADUCAH Oc
208472	CAREY Oc
208473	TELL Oc

Service Area	Description
208474	NEWLIN ENVIRON Oc
208475	ESTELLINE Oc
208476	GOODLETT Oc
208477	PANTEGO Oc
208478	WESTLAKE Oc
208479	ALMA Oc
208480	RICE Oc
208481	STAR HARBOR Oc
208482	SOMERVILLE Oc
208483	LAVON Oc
208485	FAIRVIEW (COLLIN) Oc
208486	HICKORY CREEK Oc
208487	HEATH Oc
208488	HASLET Oc
208489	SOUTHLAKE Oc
208490	OAK LEAF Oc
208492	AVALON Oc
208493	PAINT ROCK Oc
208494	GLENN HEIGHTS Oc
208495	RETREAT Oc
208496	LEONA Oc
208497	SALTILLO Oc
208498	LITTLE ELM Oc
208500	SAN ANGELO Oc
208501	AVOCA Oc
208502	MILES Oc
208503	ROWENA Oc
208504	BRONTE Oc
208505	ARCHER CITY Oc
208506	CLARENDON Oc
208507	HEDLEY Oc
208508	HOLLIDAY Oc
208509	MEGARGEL Oc
208510	OLNEY Oc
208511	TOCO Oc
208512	ANGUS Oc
208513	ROSS Oc
208514	CEDAR PARK Oc
208515	THE COLONY Oc
208516	GRAYSON CO IND PK Oc
208518	TRAVIS Oc
208519	CROSS ROADS (DENTON) Oc
208521	RENO(PARKER CO) Oc
208522	SUN VALLEY Oc
208523	BRUSHY CREEK Oc
208524	CORINTH Oc
208525	LEANDER Oc
208526	GOODLOW Oc
208527	MCCAULLEY Oc
208528	MARSHALL CREEK Oc
208529	BUTTERCUP CREEK Oc
208531	LINCOLN PARK Oc
208532	KNOLLWOOD Oc
208533	PECAN HILL Oc
208534	NORTHLAKE Oc
208535	CORRAL CITY Oc
208536	LONGVIEW Oc
208537	LAKEPORT Oc
208538	ROLLING MEADOWS Oc
208539	BAMBURG Oc
208540	SABINE Oc
208541	LELIA LAKE Oc
208542	MOBILE CITY Oc
208543	SAMNORWOOD Oc
208544	VALLEY VIEW(WICHITA) Oc
208545	TROPHY CLUB Oc
208546	COPPELL GAS LIGHTS Oc
208547	IOWA PARK GAS LIGHTS Oc
208560	LOFTIN Oc
208580	MAMBRINO Oc
208592	GILLILAND Oc
208593	KURTEN Oc
208596	CASHION COMMUNITY Oc
208597	RIVER CREEK Oc
208598	HORSESHOE Oc
208599	PECANWAY Oc
208600	WICHITA FALLS Oc
208617	OVILLA Oc
208630	TALTY Oc
208638	DOUBLE OAK Oc
208639	PARKER Oc
208640	BARTONVILLE Oc
208644	COPPER CANYON Oc
208698	WIXON VALLEY Oc
208700	WACO Oc
208701	STONEY RIDGE Oc
208702	UNION HILL Oc
208703	CROSSROADS-HENDERSON Oc
208704	BRAZOS BEND Oc
208705	ARTHUR CITY_Oc
208706	BRUCEVILLE_Oc
208707	CROWELL_Oc
208708	DEL VALLE_Oc

Service Area	Description
208709	EDDY_Oc
208710	EDGEWOOD_Oc
208711	FLINT_Oc
208712	GLADEWATER_Oc
208713	GRAPELAND_Oc
208714	JACKSONVILLE_Oc
208715	KILGORE_Oc
208716	HENDERSON_Oc
208717	ELKHART_Oc
208718	OVALO_Oc
208719	OVERTON_Oc
208720	POWDERLY_Oc
208721	SHEPPARD AFB_Oc
208722	VALLEY VIEW_Oc
208723	WILLS POINT_Oc
208724	PORT ARTHUR_Oc
208725	BAGWELL_Oc
208726	CUNEY_Oc
208727	DUNN_Oc
208728	FLORENCE_Oc
208729	HEIDENHEIMER_Oc
208730	KLONDIKE_Oc
208731	MERTENS_Oc
208732	NAVAL AIR STATION/ JRB_Oc
208733	TURKEY_Oc
208734	WARING_Oc
208735	MILDRED_Oc
208736	ALEDO_Oc
208738	Post Oak Bend Ic
208739	Winnsboro Oc
208740	IOLA_Oc
208741	APR_Oc
208742	Weatherford Oc
208743	McLendon-Chisholm_Oc
208746	Charges w/o Service_Oc
208751	DEW Oc
208800	RIGHT OF WAY Oc
208806	SOMMERVILLE GC101 Oc
208807	SOMMERVILLE GC102 Oc
208810	CENTRAL Oc
208820	SOMMERVILLE GC107 Oc
208821	MANOR-GC Oc
208822	COLLEGE STATION-GC Oc
208850	FORT WORTH Oc
208851	BENBROOK Oc
208852	EDGECLIFF VILLAGE Oc
208853	FOREST HILL Oc
208854	HALTOM CITY Oc
208855	KENNEDALE Oc
208856	LAKESIDE Oc
208857	LAKE WORTH Oc
208858	NORTH RICHLAND HILLS Oc
208859	RICHLAND HILLS Oc
208860	RIVER OAKS Oc
208861	SANSOM PARK VILLAGE Oc
208862	WESTOVER HILLS Oc
208863	WESTWORTH VILLAGE Oc
208864	WHITE SETTLEMENT Oc
208865	BLUE MOUND Oc
208867	RENDON Oc
208911	DALLAS Oc
208912	HIGHLAND PARK Oc
208913	UNIVERSITY PARK Oc
208914	COCKRELL HILL Oc
700000	Atmos Pipeline - Texas
700001	State - Payment Only
700002	Anderson County
700003	Abbott
700004	Abilene
700006	Addison
700009	Allen
700011	Alvarado
700012	Bell County
700014	Brazos County
700017	Anson
700018	Argyle
700021	Arlington
700023	Athens
700024	Aubrey
700025	Austin
700026	Azle (Parker County)
700027	Comanche County
700028	Bangs
700030	Ballinger
700031	Cooke County
700032	Bardwell
700033	Coryell County
700034	Barry
700035	Bedford
700036	Delta County
700037	Bells
700038	Belton
700039	Blackwell

Service Area	Description
700040	Blooming Grove
700041	Erath County
700042	Falls County
700044	Bonham
700045	Boyd
700046	Franklin County
700047	Bowie
700048	Brownwood
700050	Bryan
700051	Bronte
700053	Buffalo
700054	Grimes County
700055	Burkburnett
700056	Burleson
700057	Burnet
700058	Caddo Mills
700060	Hamilton County
700061	Bethel Storage LSP Pipeline
700062	Opelika Comp-Henderson County
700063	North Henderson Comp LSP Pipe
700064	Tri-Cities M Line Comp LSP Pi
700065	Canton
700066	Tri-Cities Stor Comp LSP Pipe
700067	Hill County
700068	Hood County
700071	Carrollton
700072	Cayuga
700073	Cedar Hill
700074	Hunt County
700075	Cedar Park
700076	Jack County
700079	Cisco
700080	Clarksville
700081	Chapel Hill
700082	Cleburne
700083	Childress
700084	College Station
700085	Colleyville
700086	Lamar County
700087	Clyde
700089	Comanche
700090	Coleman
700091	Lampasas County
700092	Leon County
700094	Coppell
700096	Madison County
700097	Corinth
700098	Corsicana
700099	Mclennan County
700100	Midland County
700101	Milam County
700102	Mitchell County
700104	Dallas
700105	Navarro County
700106	Decatur
700107	Deer Park
700109	Denison
700110	Parker County
700111	Denton
700112	Desoto
700114	Rains County
700115	Dublin
700117	Duncanville
700118	Runnels County
700119	Early
700120	Eastland
700121	LSP Ntw-Lake Dallas Storage
700122	Lapan Storage LSP Pipeline
700123	New York Storage LSP Pipeline
700126	Edom
700127	San Saba County
700128	Line 73 Compressor LSP
700129	Scurry County
700130	Smith County
700131	Emhouse
700132	Emory
700133	Ennis
700134	Tom Green County
700135	Everman
700136	Fairfield
700137	Fairview (Collin)
700138	Fairview (Wise)
700139	Farmers Branch
700140	Fate
700141	Ferris
700143	Flower Mound
700144	Forney
700145	Wise County
700146	Fort Worth
700148	Frisco
700150	Fredericksburg
700151	Frost
700152	Gainesville

Service Area	Description
700153	Garland
700154	Gatesville
700155	Garrett
700156	Georgetown (Outside SPD)
700157	Glen Rose
700158	Godley
700159	Gordon
700160	Gorman
700161	Granbury
700162	Grand Prairie
700163	Grandview
700164	Greenville
700165	Grapevine
700166	Groesbeck
700167	Hamilton
700168	Haslet
700169	Hearne
700170	Iola Compressor LSP Pipeline
700171	Heath
700172	North Zulch Compressor LSP Net
700173	Haskell
700174	Gulf Coast Sys - Line V4 LSP P
700175	Katy Compressor LSP Pipeline
700176	Waller Compressor LSP Pipeline
700177	Henrietta
700178	Grosbeck Compressor LSP Pipeline
700180	Henderson
700181	Hickory Creek
700183	Hillsboro
700184	Holland
700185	Hubbard
700186	Hurst
700187	Hutchins
700188	Irving
700189	Iowa Park
700190	Itasca
700191	Jacksboro
700192	Josephine
700193	Joshua
700194	Justin
700195	Katy
700196	Kaufman
700197	Keene
700198	Keller
700199	Kemp
700200	Kerens
700201	Kerrville
700202	Killeen
700203	Knox City
700204	Lake Dallas
700205	Lakeside
700206	Lake Worth Village
700207	Lampasas
700208	Lancaster
700209	Lexington
700210	Lewisville
700211	Leander
700212	LSP Ntw-Abilene Compressor
700213	LSP Ntw-Stamford Compressor
700214	EPI-Stamford Compressor
700215	Little River Academy
700217	Longview (Gregg County)
700219	Waha Header LSP Pipeline
700222	LSP Ntw-Pecan Storage
700223	LSP Ntw-Clarkson Compressor
700224	LSP Ntw-Oakridge Compressor
700225	Maryneal Compressor LSP Pipe
700226	LSP Ntw-Snyder Compressor
700227	Huckaby Compressor-LSP
700228	Mansfield
700229	Marlin
700230	Maypearl
700231	Mckinney
700232	Madisonville
700233	Marble Falls
700234	Mesquite
700235	Mexia
700236	Midlothian
700237	Midlothian
700238	Monahans
700239	Moody
700240	Murchison
700241	Nevada
700242	Newark (Wise County)
700243	Nolanville
700244	Nocona
700245	North Richland Hills
700246	Northlake
700247	Oakwood
700248	Ovilla
700249	Howard Compressor LSP Pipeline
700250	O'Brien
700251	Palestine

Service Area	Description
700252	Palmer
700253	Paradise
700254	Paris
700256	Penelope
700257	Plano
700258	Pilot Point
700261	Poynor
700263	Prosper
700265	Quitman
700266	Ranger (Outside Hospital District)
700267	Red Oak
700268	Reno-Lamar Co
700269	Rhome
700270	Rice
700271	Richardson
700272	Richland
700273	Riesel
700274	Roanoke
700275	Robert Lee
700276	Rockwall
700277	Round Rock
700278	Rowlett
700279	Eastland Memorial Hospital District
700280	Royse City
700281	Runaway Bay
700282	San Angelo
700284	Saginaw
700285	Savoy
700287	Seagoville
700288	LSP Pipeline
700290	Shady Shores
700292	Sherman
700293	Snyder
700294	Somerville
700295	Indirect Const Overhead
700296	Santa Anna
700297	Fort Worth Crime Control District
700298	Sherman Compressor
700299	Springtown
700301	Stephenville
700302	Sugar Land
700303	Sulphur Springs
700304	Sunnyvale
700305	Sweetwater
700306	Taylor
700307	Teague
700308	Temple
700309	Terrell
700310	The Colony
700311	Tioga
700313	Tyler
700314	Vernon
700315	Venus
700316	Waco
700317	Tye
700318	Waxahachie
700319	Walnut Springs
700321	Whitehouse
700322	Wichita Falls (Wichita County)
700323	Wolfe City
700324	Wylie
700330	Oklaunion Unincorp
700331	Rolling Meadows Unincorp
700337	Outside City Limits-Accru Only
700338	Suspense Balance
700340	L8-B (2Nd)-Lsp
700341	Texas
700342	Texas TRC - Regulated
700343	Oklahoma
700344	Snyder Compressor Station
700501	Howard - Enbridge Compressor
700502	WAHA & Compressor Station
710000	NSL-Atmos Only
711000	NSL-Partnership
711001	NSL-Howard - ETF Compressors
711002	NSL-Ponder Compressors
800000	Storage-Corporate
800001	Barnsley
800002	Kansas
800003	Suspense Center
810000	TransLa Energy Services
810700	Lafayette-TL Energy Services
810701	TLES-Mansfield
810702	TLES-Natchitoches
810703	Winnfield-TL Energy Services
810706	Many-TL Energy Services
810729	Olla-TLES
810766	New Iberia-TL Energy Services
811000	WKG Energy Services
811500	Owensboro
811501	Beaver Dam
811502	Calhoun
811503	Cloverport

DOCKET NO. 14-00146
ATTACHMENT 1
TO MFR NO. 1-05

Service Area	Description
811504	Fordsville
811505	Hardinsburg
811506	Hartford
811507	Hawesville
811508	Whitesville
811515	Madisonville
811516	Earlington
811517	Hanson
811518	Morton's Gap
811519	Nortonville
811520	St Charles
811521	Sebree
811522	Dixon
811523	Slaughters
811524	South Henderson
811527	Wkg Measurement
811530	Princeton
811531	Cadiz
811532	Dawson Springs
811533	Eddyville
811534	Marion
811535	Fredonia
811537	Hopkinsville
811538	Crofton
811540	Greenville
811541	Central City
811542	Bremen
811543	Powderly
811544	Sacramento
811545	Rural Owensboro
811546	Rural Madisonville
811547	Rural Paducah
811548	Rural Bowling Green
811549	Rural Danville
811550	Paducah
811551	Calvert City
811552	Gilbertsville
811553	Grand Rivers
811555	Mayfield
811556	Water Valley
811557	Wingo
811558	Symsonia
811560	Bowling Green
811562	Russellville
811563	Adairville
811564	Elkton
811565	Franklin
811566	Auburn
811567	Woodburn
811570	Glasgow
811571	Cave City
811572	Hiseville
811573	Horse Cave
811574	Munfordville
811575	Oakland
811576	Park City
811577	Smith's Grove
811580	Danville
811581	Hustonville/Moreland
811582	Junction City
811583	Lancaster
811584	Perryville
811585	Stanford
811587	Lebanon
811588	Springfield
811590	Harrodsburg
811591	Greensburg
811592	Campbellsville
811593	Greensburg
811595	Shelbyville
811596	Lawrenceburg
811599	Wkg BU A&G
812000	United Cities Energy Services
812130	Union City
812135	Colombia
812140	Shelbyville
812144	Franklin
812145	Murfreesboro
812151	Maryville
812152	Johnson City
812153	Kingsport
812154	Tri-Cities
812155	Green
812156	Morristown
812157	Johnson City
812159	Elizabethtown
812162	Alcoa IS_CL
812163	Abingdon
812164	Marion
812165	Wytheville
812166	Pulaski
812168	Radford
812169	Blacksburg

Service Area	Description
812170	Gaffney SC
812175	Gainsville GA
812180	Columbus
812181	Virden
812182	Vandalia
812183	Bristol
812189	Keokuk
812191	Hannibal
812192	Canton
812195	Palmyra
812680	Bowling Green
812681	Edina
812682	Kahoka
812683	La Belle
812684	La Grange
812686	Memphis
812905	Elizabethton
812906	Bristol, VA
812907	Abingdon
813000	Greeley Energy Services
813250	Bonner Springs-GES
813251	Bonner Springs-GES
813252	Kansas City
813253	Edwardsville-GES
813254	Eudora-GES
813255	GES-Lawrence
813256	De Soto-GES
813257	Wilder-GES
813258	GES-Clearview City
813259	GES-Shawnee - R
813261	Lenexa-GES
813262	Olathe-GES
813263	Basehor-GES
813264	Rosedale-GES
813265	Lincoln Park-GES
813266	Parlin-GES
813267	Lake of the Forest-GES
813268	Monticello Twp-GES
813269	Wilsey-GES
813270	Almont
813271	Fairmont Township-GES
813273	Pleasanton-GES
813274	Mound City-GES
813275	GES-Prescott
813276	GES-Fulton
813277	GES-Redfield
813278	Fort Scott-GES
813279	Fairmont Township-GES
813280	Potosi Township-GES
813281	Sheridan Township-GES
813282	Freedom Twp-GES
813283	Marmation Twp-GES
813284	Osage Twp-GES
813285	Scott Township-GES
813286	Mill Creek Township-GES
813300	Herington-GES
813301	Delavan-GES
813302	Lost Springs-GES
813304	Township #7-GES
813330	Council Grove-GES
813331	Council Grove 2-GES
813332	White City-GES
813334	Cottonwood Falls-GES
813335	GES-Strong City
813345	Marion-GES
813346	Hillsboro-GES
813347	Lincolnville-GES
813348	GES-Marion Lake
813349	Peabody-GES
813350	Tampa-GES
813351	Pilsen-GES
813352	Aulne-GES
813353	Ramona
813354	Florence-GES
813356	Clear Creek Township-GES
813364	Peabody, KS-GES
813365	Yates Center-GES
813366	Yates Center-GES
813367	Coffeeville-GES
813368	Independence-GES
813369	Johnson County-Olathe
813370	Ness City-GES
813371	Bazine-GES
813372	GES-Alexander
813373	GES-McCraken
813374	Danville-GES
813375	Anthony, KS-GES
813376	GES-Hunnewell
813377	South Haven-GES
813378	Caldwell-GES
813379	GES-Hazelton
813380	Fredonia
813381	Galesburg

Service Area	Description
813382	Linwood
813383	Anthony-GES
813384	Mound Valley
813385	Eureka-GES
813386	Neal-GES
813387	Toronto-GES
813388	GES-Danville
813389	Spring Hill
813390	Batchelor Township-GES
813455	GES-Johnson
813456	Manter-GES
813457	Big Bow Township-GES
813458	Manter Township-GES
813459	Stanton Township-GES
813460	Richfield Township-GES
813461	Westola Township-GES
813465	Ulysses-GES
813466	Hickok-GES
813467	Sherman Township-GES
813468	Sullivan Township-GES
813469	Lincoln Township-GES
813470	Harmony Township-GES
813475	Syracuse-GES
813476	Kendall-GES
813477	Bear Creek Township-GES
813478	Coolidge Township-GES
813479	Kendall Township-GES
813480	Lamont Township-GES
813481	Liberty Township-GES
813482	Syracuse Township-GES
813483	Hartland Township-GES
813557	Big Bow Township-GES
813660	Rich Hill-GES
813661	Hume-GES
813800	Denver-GES
813810	Greeley
813811	Ault
813812	Eaton
813813	Evans
813814	GES-Garden City
813815	Gilcrest
813816	Hudson
813817	Keenesburg
813818	GES-Kersey
813819	LaSalle
813820	Lucerne-GES
813821	Platteville
813823	Pierce
813824	Prospect Valley-GES
813825	Roggen
813826	Nunn
813827	Outside Ault-GES
813828	Outside Eaton-GES
813831	Outside Gilcrest-GES
813832	Outside Greeley-GES
813838	Outside Platteville-GES
813845	Graig
813846	Meeker
813847	Hayden
813849	Outside Hayden-GES
813850	Outside Graig-GES
813855	Steamboat Springs
813856	Milner-GES
813857	Outside Steamboat Springs-GES
813860	Canon City
813861	Florence, Co
813862	Portland-GES
813863	Penrose
813864	Williamsburg
813865	Rockvale-GES
813866	Outside Canon City-GES
813873	Salida
813874	GES-Poncha Springs
813875	GES-Nathrop
813877	Outside Poncha-GES
813880	Gunnison
813881	Crested Butte
813882	Mount Crested Butte-GES
813883	Outside Crested Butte-GES
813885	Outside Gunnison-Gunnison County-GES
813901	Lamar
813902	GES-Energy Park I
813903	GES-McClave
813904	Brandon
813905	Eads
813906	Bristol
813907	Granada
813908	Hartman
813909	GES-Holly
813910	Kornman-GES
813911	Wiley
813921	Outside Lamar-GES
813922	Outside Wiley-GES

Service Area	Description
813924	Springfield
813925	GES-Pritchett
813926	Two Buttes-GES
813927	Vilas
813928	Walsh
813930	Outside Springfield-GES
813935	Durango
813936	Outside Durango-GES
813938	Cortez
813939	Dolores
813940	Mancos
813941	Dove Creek
813942	Cahone-GES
813943	Egnar-GES
813944	Outside Cortez-GES
814000	Energas Energy Services Trust
814001	Big Spring
814002	Forsan-EES
814003	Coahoma
814006	Pampa
814007	Panhandle
814009	West Texas Div Office
814010	Amarillo
814015	Fritch
814016	Sanford
814020	Dalhart
814021	Channing
814022	Hartley-EES
814031	Palisades
814032	Hereford
814033	Friona
814034	Bovina
814035	Dimmitt
814036	Canyon
814037	Happy
814038	Tulia
814039	Kress
814040	Plainview
814041	Hale Center
814042	Petersburg
814043	Floydada
814044	Lockney
814045	Silverton
814046	Quitaque
814047	Turkey
814048	Littlefield
814049	Muleshoe
814050	Sudan
814051	Amherst-EES
814052	Anton
814053	Olton
814054	Earth
814055	Levelland
814056	Lubbock
814057	Abernathy
814058	Shallowater
814059	Idalou
814060	Ralls
814061	Lorenzo
814062	Crosbyton
814063	Slaton
814064	Southland
814065	Post
814066	Wilson
814067	Tahoka
814068	O'Donnell
814069	Lamesa
814070	Brownfield
814071	Ropesville-EES
814072	Meadow
814073	Seagraves
814074	Seminole
814075	Midland
814076	Stanton
814077	Odessa
814078	Whitharral-EES
814079	Wolfforth
814080	New Deal
814081	Springlake-EES
814082	Vega
814083	Hart
814086	Welch
814087	Edmonson-EES
814088	New Home
814089	Smyer-EES
814090	Village of Tanglewood-EES
814091	Nazareth
814092	Wellman
814093	Ransom Canyon
814094	EES-Timbercreek Canyon
814096	Los Ybanez
814097	Opdyke
814098	Buffalo Spring Lake

Service Area	Description
814110	Bushland
814114	Dawn
814149	Spade
814171	Lenorah
814201	Claude
815000	Atmos Energy Marketing LLC
816000	Atmos Nonregulated Shared Services
817000	WKG Storage Inc
817001	WKG Storage-East Diamond
817002	WKG Storage-Crofton
817003	WKG Storage-Alcan Pipeline
817004	WKG Storage-Tar Springs Storage Field
818000	Atmos Pipeline & Storage Inc (Formerly
818001	Atmos Storage Lafayette Storage Field
818002	Atmos Storage Ft Necessity
820000	AEHI Corporate
821000	Woodward Corporate
821001	Southern Resources
822000	TLGS-Corporate
822001	TLGS-Ft Necessity
823000	TLIG-Corporate
824000	WMLLC Franklin
825000	AEM - Owensboro, KY
825001	AEM - Louisville, KY
826000	WMLLC New Orleans
827000	WMLLC Dallas
828000	AEM-Louisiana
829000	Fort Necessity Gas Storage, LLC
830000	Blueflame
831000	AEM-Fair Hope, AL
832000	AEM-Olathe, KS
833000	AEM-Virginia Beach, VA
834000	AEM - Louisville, KY
835000	Straight Creek Gathering, LP
840000	PDH Holdings
850000	Propane
861000	Shrewsbury
862000	Atlas Engineering Interconnect
863000	O'Brien Resources
864000	NHHG LLC
865000	Straight Cr Gathering LP
866000	Phoenix Gas Gathering Company
867000	Straight Cr Gathering Co LLP
867001	Illinois Gas Transmission
868000	Park City
869000	Pioneer CBM
870000	Utility Services
870001	No name on file
870002	No name on file
870003	No name on file
870004	No name on file
870005	Exploration
870006	Woodward Marketing
870007	General Office
870008	General Office
870009	No name on file
870010	Utility Services
870011	Field Services
870012	Natural Gas Brokerage
870013	Energy Marketing
870014	Applianceguard
870015	Suspense Center
870170	Gaffney SC
870175	Gainsville GA
870180	Columbus GA
871000	Kentucky Blue Gas
872000	Perdue Farms
880000	Rental
880130	Union City-Rental Division
880132	Brentwood Corporate Office
880135	Columbia-Rental Division
880140	Shelbyville-Rental Division
880144	Franklin
880145	Murfreesboro-Rental Division
880151	Maryville-Rental Division
880153	Kingsport
880154	Bristol-Rental Division
880155	Greeneville-Rental Division
880156	Morristown-Rental Division
880157	Johnson City
880164	Marion
880165	Wytheville
880166	Pulaski
880168	Radford
880169	Blacksburg
880170	Gaffney-Rental Division
880175	Gainesville
880180	Columbus
880181	Virden
880182	Vandalia-Rental Division
880184	Salem
880185	Harrisburg-Rental Division
880186	Metropolis-Rental Division

Service Area	Description
880189	Keokuk
880190	Neelyville
880191	Hannibal
880192	Canton
880365	Wyandotte
880366	Yates Center
880367	Coffeyville
880368	Independence
880369	Olathe
880901	Overland Park
880902	Energy Park I
880903	Energy Park II
880904	Energy Park III
880905	Elizabethton-Rental Division
880906	Bristol, VA
880907	Abingdon
880908	Exploration Division
880909	General Office
880910	No name on file
880911	No name on file
880912	No name on file
890000	Atmos Power Systems (Formerly Leasing)
890001	Number of Propane Customers
890002	No Center Name on File
890003	Suspense Center
890004	Tenn Power Projects
890005	Bolivar
890006	Staley
890100	COLUMBUS - RENTAL
890144	GENERAL OFFICE - RENTAL
890170	GAFFNEY - RENTAL
890175	GAINESVILLE - RENTAL
900000	Non-utility Eliminations
910000	AEM Intracompany Elims
930000	MS Energy
940000	MS Water
950000	Mississippi Wastewater
979000	Amarillo Elimination
980000	Triangle Elimination
981000	Atmos Energy Corporation Cons (Elim)
982000	Atmos Energy Company (BU Elim)
983000	Atmos Storage (Elim)
984000	Atmos Energy Services (Elim)Atmos Stora
985000	Enertrust Inc (Elim)
986000	Atmos Energy Marketing (Elim)
987000	Other Operating Companies (Elim)
988000	West Texas Div Enermaty (Elim)
989000	Blueflame (Elim)
990000	Mid-Tex Eliminations
991000	Straight Creek Eliminations
999999	Suspense

REQUEST:

Provide copies of all rate case orders for the LDC, its Parent, Multi-State Utility, or Affiliated Utility Service Company issued since the LDC's last rate case or within the past three (3) years, whichever time is shorter.

RESPONSE:

Please see the below list of Atmos Energy rate cases in which Commission orders or recommended decisions were issued since June 2012. Please see Attachment 1 for a copy of the orders and recommended decisions.

Colorado	Docket No. 13AL-0496G
Colorado	Docket No. 14AL-0330G
Kansas	Docket No. 12-ATMG-564-RTS
Kansas	Docket No. 14-ATMG-320-RTS
Kentucky	Case No. 2013-00148
Mid-Tex	GUD 10170
Tennessee	Docket Number 12-00064
Virginia	PUE-2013-00124
West Texas	GUD 10174
West Texas	City Jurisdiction (see one ordinance for an example of what the Cities approved)

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_1-06_Att1 - Rate Orders.pdf, 517 Pages.

Respondent: Patricia Childers

Decision No. R14-0198

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 13AL-0496G

IN THE MATTER OF ADVICE LETTER NO. 497, FILED BY ATMOS ENERGY CORPORATION TO PLACE INTO EFFECT TARIFF SHEET CHANGES TO BE EFFECTIVE ON JUNE 10, 2013.

RECOMMENDED DECISION OF ADMINISTRATIVE LAW JUDGE G. HARRIS ADAMS APPROVING STIPULATION AND SETTLEMENT AGREEMENT

Mailed Date: February 24, 2014

TABLE OF CONTENTS

I. STATEMENT

1. This matter comes before the Commission for consideration of the Stipulation and Settlement Agreement filed on January 15, 2014 (Settlement Agreement), in the above-captioned rate case proceeding initiated by Atmos Energy Corporation (Atmos Energy or the Company). The Settlement Agreement (including Attachments 1 and 2 thereto), attached hereto as **Appendix A**, is signed by Atmos Energy; the Trial Staff of the Public Utilities Commission of the State of Colorado (Staff); the Colorado Office of Consumer Counsel (OCC); and Energy Outreach Colorado (EOC), (collectively the Parties and individually a Party). The Settlement Agreement is unopposed.

2. Now being fully advised in the matter, the Administrative Law Judge (ALJ) finds that the resolution of this proceeding, as achieved by the Settlement Agreement, is just and reasonable and in the public interest, and that the Settlement Agreement results in just and reasonable rates for the utility service provided by the Company in Colorado. For the reasons set forth below, the ALJ approves the resolution of the proceeding agreed to by the Parties and as reflected in the Settlement Agreement, since it is consistent with the standards of § 40-3-101, C.R.S.

A. Procedural History

3. On May 8, 2013, Atmos Energy filed Advice Letter No. 497 to implement an increase in its gas department base rates.[1] Atmos Energy requested that the tariffs become effective on June 10, 2013. Atmos Energy filed testimony with Advice Letter No. 497 and proposed a multi-year rate plan (MYP) based on Forecasted Test Years (FTYs) for 2014 through 2016. The Company sought a rate increase of approximately $10.4 million over three years.

4. On May 24, 2013, by Decision No. C13-0620, the Commission suspended the proposed effective date of the proposed tariff sheets filed with Advice Letter No. 497 until October 9, 2013, set the matter for hearing pursuant to § 40-6-111(1), C.R.S., and referred the matter to the undersigned ALJ for a recommended decision.

B. Staff and the OCC Timely Intervened of Right.

5. Decision No. R13-1022-I, issued on August 19, 2013, granted EOC and Public Service Company of Colorado (Public Service) intervenor status; further suspended the proposed effective date of the tariff sheets filed with Advice Letter No. 497 until December 31, 2013; established a procedural schedule; and approved an across-the-board General Rate Schedule Adjustment (GRSA) of 12.85 percent to be placed in effect on January 1, 2014, subject to a refund condition and subject to whether or not the Commission established new rates by that date.

[1] An amended Advice Letter No. 497 was filed on May 9, 2013, to correct clerical errors.

6. Decision No. R13-1301-I, issued October 17, 2013, modified the procedural schedule to allow additional time in the schedule for the intervenors to file Answer Testimony. On November 12, 2013, Staff, EOC, and the OCC filed Answer Testimony. On December 17, 2013, by Decision No. R13-1547-I, Public Service's request to withdraw its intervention in this proceeding was granted. Public Service is no longer a party to the proceeding.

7. On December 20, 2013, Atmos Energy, Staff, and EOC filed a Stipulation and Settlement Agreement (Partial Settlement Agreement). Decision No. R13-1593-I, issued December 24, 2013, modified Decision No. R13-1022-I to reflect a GRSA of 5.14 percent to go into effect on January 1, 2014 subject to a refund condition, and permitted the filing of testimony in support of the Partial Settlement Agreement.

8. On December 26, 2013, Atmos Energy filed Advice Letter No. 506 with its accompanying tariff sheets to reflect the 5.14 percent GRSA in Proceeding No. 13AL-1377G and such went into effect on January 1, 2014 pursuant to Commission Decision No. R13-1583-I issued December 24, 2013.

9. On January 8, 2014, Atmos Energy filed Rebuttal Testimony. On January 8, 2014, Atmos Energy, Staff, and EOC filed Direct Testimony in support of the Partial Settlement Agreement.

10. On January 15, 2014, Atmos Energy, Staff, EOC, and the OCC filed the Settlement Agreement, which sought to replace the Partial Settlement Agreement and resolved all of the issues that were raised by all of the Parties in this proceeding.

11. On January 21, 2014, Decision No. R14-0075-I modified Decision No. R13-1583-I, and authorized Atmos Energy to make a compliance filing changing the GRSA to 4.06 percent subject to a refund condition, to become effective March 1, 2014 consistent with

the provisions of the Settlement Agreement. Also on January 21, 2014, by Decision No. R14-0078-I, the procedural schedule was modified, the continued hearing dates of February 13 and 14, 2014 were vacated, and a single day of hearing on the Settlement Agreement was scheduled for February 12, 2014.

12. On February 7, 2014, by Decision No. R14-0156-I, the hearing scheduled to commence on February 12, 2014 was vacated. Pursuant to the terms of the Settlement Agreement, the Parties waived cross-examination and agreed to the admission of all pre-filed testimony and exhibits filed in this proceeding, as corrected on February 5, 2014. Such pre-filed testimony and exhibits will be admitted and relied upon for determination of the pending motion.

II. DISCUSSION

A. Summary of the Pre-Filed Testimony

1. Atmos Energy

13. Along with Advice Letter 497, Atmos Energy filed the direct testimony of ten witnesses, which is summarized below:

- Karen P. Wilkes: Introduced the Company's other witnesses, provided an overview of the Company and the proposed MYP, setting forth the principal factors requiring Atmos Energy to file the rate application, and summarizing: (1) the Company's request for a statewide Gas Cost Adjustment (GCA); (2) the Company's request to recover its investment in Advanced Metering Infrastructure (AMI); (3) the Company's proposed approach to recover infrastructure investments related to the System Safety and Integrity Program (SSIP); (4) the Company's request to recover gas and non-gas components of uncollectible accounts in base rates; and (5) the Company's request for additional tariff revisions associated with this filing.
- Joe T. Christian: Discussed the MYP and associated earnings test, the Company's MYP cost of service studies, projected operation and maintenance as well as the taxes -- other than income taxes -- included in the FTY cost of service studies, the inclusion of all AMI investment in base rates, and the importance and recovery of the Company's proposed SSIP.

- John M. Willis: Described the Company's Colorado gas system and pipeline safety, overall capital spending included in the proposed MYP, and the SSIP.

- Ann E. Bulkley: Provided a recommendation regarding the need for a fair and reasonable return on equity and the Company's proposed capital structure to be used for ratemaking purposes.

- William H. Meckling: Presented and supported the Company's proposed cost allocation, rate design, the proposed rates, and changes to the Company's construction allowance.

- Thomas H. Petersen: Discussed the Company's rate base calculation and the calculation of depreciation expense and Cash Working Capital, and presented the Company's Class Cost of Service Study.

- Ryan C. Hockin: Presented the Company's MYP revenues and associated billing determinants in support of the respective base rate revenue increases over each of the three FTY periods.

- Jason L. Schneider: Provided support for the Company's historic Books and Records, sponsored the Company's Cost Assignment and Allocation Manual, and presented the methodology for cost allocation and the Shared Services allocations.

- John C. Johnson: Presented the Shared Services Depreciation Study as well as the current and proposed depreciation rates applicable to the Company's Shared Services assets.

- Jared N. Geiger: Discussed the need for consolidation of Atmos Energy's GCA rates and the request for a single statewide GCA rate, applicable to all rate areas within Atmos Energy's Colorado Service Area.

2. Commission Staff

14. In response to Atmos Energy's direct testimony, Staff filed answer testimony of five witnesses, which are summarized below:

- Karlton Kunzie: Introduced Staff's other witnesses and addressed the Company's proposed FTYs and MYP, the Company's proposed rate base calculation, the Company's proposal for inclusion of AMI costs, the Company's proposal to include gas storage inventory costs in rate base, the Company's proposal for inclusion of construction work in progress in rate base, and provided Staff's recommended revenue requirement increase based on Staff's historic test year (HTY).

- Dr. Scott E. England: Discussed the Company's requested capital structure and rate of return on rate base, provided Staff's recommended rate of return on equity and the proper level of debt and cost of debt to use in the overall rate of return, provided Staff's recommended return on rate base (or weighted average cost of capital) for Staff's HTY, provided Staff's recommended return on rate base for each of the Company's FTYs, and discussed the earnings test and Staff's recommendation that it be rejected.

- Richard Reis: Addressed the Company's proposal to consolidate its existing GCA zones from four into one average system-wide calculation and rate, discussed the Company's proposal to increase the facility charge for residential customers from the existing $10.00 per bill to $16.10, and provided Staff's analysis regarding certain rate case expenses.

- Sandi M. Kahl: Addressed the Company's proposal to include estimated capital investment in each of the FTYs and provided Staff's recommendations on the proper rate case expense recovery mechanism.

- William W. Harris: Addressed weather normalized billing determinants and the associated revenues for Staff's HTY and the Company's FTYs.

3. OCC

15. In response to Atmos Energy's direct testimony, the OCC filed answer testimony of three witnesses, which are summarized below:

- Cory Skluzak: Introduced the OCC's other witnesses and addressed the Company's MYP proposal, the Company's baseline test year which was the starting point for the OCC's recommended HTY, the OCC's 19 proposed adjustments to the Company's adjusted baseline test year rate base and income statement which were used to develop the OCC's HTY recommended revenue requirement, the OCC's HTY revenue requirement model, the Company's Phase II proposals regarding cost allocation and rate design change to increase the fixed customer charge, and the Company's proposal to consolidate the GCA rates and areas into a single GCA.

- Thomas Dixon: Addressed historic and FTY issues in general, the Company's proposal to use three future test years, and the OCC's recommendation to continue using an HTY approach to establish the Company's revenue requirement.

- Ronald Fernandez: Addressed adjustments to the OCC's revenue requirement model for the HTY on rate of return issues, including the OCC's recommended capital structure and return on equity proposals, and addressed the Company's earnings sharing and stay-out provision proposals that were included as part of the Company's MYP.

16. In response to Atmos Energy's direct testimony, EOC filed answer testimony of one witness, which is summarized below:

4. EOC

- William B. Marcus: Identified and addressed issues with the Company's proposed revenue requirement and cost of service study that reduce both the residential class allocation and the residential customer cost and addressed the Company's proposal to increase the residential customer charge.

17. In addition to the direct and answer testimony filed in this proceeding, Atmos Energy filed the rebuttal testimony of seven witnesses (Ms. Wilkes, Mr. Christian, Mr. Willis, Ms. Bulkley, Mr. Meckling, Mr. Petersen, and Mr. Hockin). The Company (Ms. Wilkes), Staff (Mr. Kunzie), and the EOC (Mr. Arnold) all provided additional testimony in support of the Partial Settlement Agreement. The Company (Ms. Wilkes), EOC (Mr. Arnold), and the OCC (Mr. Skluzak) all provided additional testimony in support of the Settlement Agreement.

B. Summary of the Contested Issues

18. The Parties' initial positions on the issues relevant to the Settlement Agreement are summarized below.

C. Test Year

19. Atmos Energy proposed the implementation of an MYP based on FTYs for 2014 through 2016. The Company sought a rate increase of approximately $10.4 million over three years. The MYP included earnings test and "stay-out" provisions. Staff recommended that the Commission reject the FTYs and MYP as proposed by Atmos Energy and advocated for the use of the 2012 historic test year (HTY), with adjustments. The OCC recommended that the

Commission reject the FTYs and MYP based on the FTYs and adopt an HTY for the 12 months ended December 31, 2012, as adjusted by the OCC.

D. Return on Equity and Capital Structure

20. Atmos Energy identified 10.25 to 10.75 percent as the range of reasonableness for its Return on Equity (ROE) and proposed an authorized ROE of 10.50 percent. The Company proposed a capital structure consisting of 52.68 percent common equity and 47.32 percent long-term debt, based on the historical period ending December 31, 2012. For the HTY, Staff recommended a capital structure of 47.43 percent debt and 52.57 percent equity and an authorized ROE of 9.42 percent. The OCC recommended that if the Commission utilized an HTY, then the Commission should adopt an authorized ROE for Atmos Energy of 9.0 percent and a capital structure of 52.7 percent equity and 47.3 percent debt.

E. End of Year vs. 13 Month Average Rate Base

21. The Company used an end of year rate base (as of December 31, 2012) to prepare the baseline cost of service study (referred to as the "HTY"). Staff and OCC both recommended that the Commission reject Atmos Energy's use of year-end rate base and use a 13-month average rate base instead.

F. Gas Storage Inventory

22. Atmos Energy proposed to include net plant in service, storage gas, accumulated deferred income tax, customer advances, customer deposits, prepaid pension, other prepayments, and Cash Working Capital (CWC) requirements in rate base. Staff and the OCC recommended that gas storage inventory should be removed from rate base and a carrying charge based upon short-term interest rates should be collected in the Gas Cost Adjustment (GCA).

The OCC also recommended adjustments due to the inclusion of prepayments in CWC and the absence of interest on long-term debt in CWC.

G. GCA Rate Areas

23. Atmos Energy requested authority to transition to a single statewide GCA, rather than continuing the use of four separate rate zones and GCAs. Staff and the OCC recommended that the Commission deny the Company's proposal to consolidate its four GCA rate zones into a single statewide GCA.

H. Advanced Metering Infrastructure

24. Atmos Energy requested authority to include all of its investment in Advanced Metering Infrastructure (AMI) in rate base and the discontinuation of the Advanced Metering Infrastructure Surcharge (AMIS). The OCC recommended that the Commission reject Atmos Energy's proposal to include all of the investment in AMI in rate base and recommended that recovery of the investment in the Greeley Pilot Project be continued through the existing AMIS mechanism. Staff recommended that the Commission eliminate all investment and depreciation expenses related to the investment in AMI, except for the costs associated with the Greeley Pilot Project, from the revenue requirement calculation. EOC did not believe that the benefits of the Greeley Pilot Project were commensurate with its costs, causing customer costs to increase.

I. System Safety and Integrity Program

25. Atmos Energy requested authority to implement a System Safety and Integrity Program (SSIP) to address the accelerated replacement of all unprotected bare steel and PVC pipeline and services over a ten-year period, along with an approach to recovering infrastructure investments related to the SSIP. Both Staff and the OCC recommended that the Commission reject the SSIP.

J. Data Integration Project

26. Atmos Energy requested authority to conduct a three-year program to convert historic records to current GIS systems, at a cost of $1 million ($333,333 per FTY period). Staff and the OCC recommended that the Commission reject the data integration project.

K. Building Projects

27. Atmos Energy requested authority to pursue three significant capital building projects as part of the MYP, consisting of the Greeley Building Project, the Cañon City Building Project, and the Salida and Gunnison Building Project. Staff recommended that the Commission should remove the estimated capital expense for the proposed building projects (totaling $13,857,000) from rate base. The OCC recommended that the Commission reject the capital building projects.

L. Residential Facilities Charge

28. Atmos Energy proposed to increase the Residential Facilities Charge from $10 per month to $16.10 per month. Staff, EOC, and the OCC recommended that the Commission deny the Company's proposal to increase the Facilities Charge for Residential customers.

M. Operation & Maintenance (O&M) and Administrative & General Expenses

29. Staff recommended removing the Company's projected rate case expenses from the Company's requested revenue requirement for base rates and replacing the projection with actual rate case expenses, and recommended that rate case expenses be recovered through a separate GRSA mechanism based upon a 36-month amortized period. Staff also recommended that the requested rate case expense for Mr. Meckling be disallowed.

30. EOC recommended that the Commission reduce the Company's administrative and general expenses by $808,000 in areas relating to the compensation of executives and

directors. EOC also recommended that the Commission reduce Atmos Energy's labor and payroll tax costs by $62,000 to correct an error in calculation of benefits from AMI. EOC recommended that the Commission should change Atmos Energy's cost allocation to allocate each type of distribution O&M expense by each type of distribution plant instead of all expenses by all plant; to allocate gas supply and transportation administration costs separately from other administration and general expenses; and to make other smaller changes.

31. The OCC recommended that construction work in progress (CWIP) not be included in the HTY rate base due to a significant imbalance (known as "slippage") between the amount of and return on CWIP, and the amount of and return on allowance for funds used during construction and which would result in a decrease in rate base of $5,407,823. The OCC also recommended that $450,000 in rate case expense be shared equally between shareholders and ratepayers, which would result in $225,000 being amortized over three years (or $75,000 per year).

N. The Settlement Agreement

32. The Settlement Agreement proposes the following resolution to all of the issues which were raised in this proceeding:

(1) The Parties agreed that Atmos Energy should be authorized a rate increase in annual base revenues consisting of two steps. Regarding the first step, for January through February 2014 Atmos Energy should be authorized an increase in annual base revenues of $1,644,000 (First Settlement Rate Increase). Regarding the second step, for the period of March 1, 2014 onwards, the authorized annual base revenue of $1,644,000 discussed in the first step should be reduced by $344,000 and Atmos Energy should be authorized an increase in annual base revenues of $1,300,000 (Second Settlement Rate Increase) as measured against the base revenues existing prior to January 1, 2014. Attachment 1 to the Settlement Agreement (pages 16-20 of Attachment A) provides the calculations supporting the First Settlement Rate Increase and Attachment 2 to the Settlement Agreement (pages 21-25 of Attachment A) provide the calculations supporting the Second Settlement Rate Increase.

(2) To calculate the First and Second Settlement Rate Increases, the Parties utilized a historic test period of the twelve months ending December 31, 2012 (the Settlement Test Period) and calculated the Settlement Test Period Rate Base using the 13-month average methodology.

(3) Both the First and Second Settlement Rate Increases utilized a rate of return on equity of 9.72 percent and a weighted average cost of capital of 8.07 percent. The rate of return calculations are set forth in greater detail in the Settlement Agreement at Attachment 1 (Schedule 2 Return on Rate Base) and Attachment 2 (Schedule 2 Return on Rate Base) (pages 17 and 22 of Attachment A). The Parties agreed that Atmos Energy's authorized rate of return on equity going forward shall be any rate of return on equity within the range of 9.5 percent to 10 percent.

(4) The Parties agreed that both Settlement Rate Increases include the revenue impact of including all of Atmos Energy's per book investments in AMI as of December 31, 2012 in base rates rather than reflecting these costs in a separate rate rider. In conjunction with the implementation of interim GRSA rates on January 1, 2014, Atmos Energy set the AMIS at $0.00. The Parties agreed that as part of the compliance filing following approval of the Settlement Agreement, Atmos Energy will discontinue the existing AMIS. Within 60 days following the final approval of the Settlement Agreement, Atmos Energy will file a final reconciliation of the AMIS through the end of 2013 as well as a proposed mechanism, if necessary, to account for any over or under collected amounts that may exist.

(5) The Parties agreed that both Settlement Rate Increases reflect the inclusion of average gas storage inventory costs during the Settlement Test Period in base rates as proposed by Atmos Energy rather than reflecting these costs in Atmos Energy's GCA mechanism. However, Staff, EOC, and the OCC specifically reserved the right to argue in a future proceeding that a different treatment of gas storage costs is appropriate.

33. Both Settlement Rate Increases reflect adjustments to the Company's filed Operations and Maintenance Expense. Specifically:

(1) The Parties agreed that authorized rate case expenses should be reduced by $100,000 (from $450,000 to $350,000) and amortized over three years.

(2) The Parties accepted Atmos Energy's proposal to include $333,333 in the revenue requirement in this case as a known and measurable adjustment to the Settlement Test Period expenses associated with Atmos Energy's data integration project which will convert Atmos Energy's historic records of its pipeline system into a geo-coded digital format. Without agreeing to the prudence of specific future expenditures for this project, the Parties agreed that the data integration project is reasonable and should proceed forward.

(3) The Parties agreed to a negative adjustment to the revenue requirement in this case to reflect imputed cost savings associated with Atmos Energy's AMI program. Atmos Energy's filing included $310,741 in AMI savings in the historic test period which decreased the proposed overall revenue requirement. In the First Settlement Rate Increase calculation, those imputed savings are increased by $289,259 to a total of $600,000 in the Settlement Test Period. In the Second Settlement Rate Increase calculation, those imputed savings are increased by an additional $344,000 to a total of $944,000 in the Settlement Test Period.

(4) The Parties agreed to a negative adjustment of $107,330 to the revenue requirement in this case based on unspecified adjustments.

(5) The Settlement Test Period O&M Expense adjustments are set forth in greater detail in the Settlement Agreement at Attachment 1 (Schedule 3 Adjustments to Operation and Maintenance Expense) and Attachment 2 (Schedule 3 Adjustments to Operation and Maintenance Expense) (pages 18 and 23 of Attachment A).

34. Both Settlement Rate Increases reflect the Parties' agreement with respect to the Settlement Test Period Rate Base. Specifically:

(1) The Parties agreed, except for the OCC who does not contest, that Atmos Energy's investments in the statewide AMI deployment are reasonable and prudent. Therefore, both Settlement Rate Increases reflect the inclusion of the per book AMI investments as of December 31, 2012 in the Settlement Test Period Rate Base.

(2) Both Settlement Rate Increases also reflect the inclusion of Atmos Energy's gas storage costs in Rate Base.

(3) The parties agreed to remove from Rate Base the post-test period changes in net plant in service that were proposed by Atmos Energy.

(4) The Rate Base agreement and adjustments are set forth in greater detail in the Settlement Agreement at Attachment 1 (Schedule 4 Adjustments to Rate Base) and Attachment 2 (Schedule 4 Adjustments to Rate Base) (pages 19 and 24 of Attachment A).

35. Both Settlement Rate Increases are proposed to be implemented in customer rates as follows:

(1) The Parties agreed to a Residential monthly Facilities Charge of $10.75. With respect to the other customer classes, the Settling Parties agreed to the monthly Facilities Charges reflected in the Settlement Agreement at

Attachment 1 (Proof of Rates) and Attachment 2 (Proof of Rates) (pages 20 and 25 of Attachment A).

(2) The Parties agreed to utilize Atmos Energy's filed Class Cost of Service Study to calculate each customer class' revenue requirement and the Distribution System Rates for each customer class.

(3) The parties agreed to maintain Atmos Energy's four separate GCA rate areas.

(4) The specific rate changes that would result from the Settlement Agreement are set forth in greater detail in the Settlement Agreement at Attachment 1 (Proof of Rates) and Attachment 2 (Proof of Rates) (pages 20 and 25 of Attachment A). Upon approval of the Settlement Agreement, Atmos Energy has committed to make a compliance Advice Letter filing to implement the rates set forth in the Settlement Agreement at Attachment 2 (Proof of Rates) (page 25 of Attachment A) and to discontinue the GRSA. To the extent a Commission Decision approving the Settlement Agreement is issued with sufficient time to allow Atmos Energy to place the approved rates into effect prior to March 1, 2014, Atmos Energy will withdraw its interim 4.06 percent GRSA rate and discontinue the GRSA.

(5) Pursuant to Commission Decision No. R13-1583-I, Advice Letter No. 506 implementing a GRSA of 5.14 percent went into effect on January 1, 2014. The GRSA of 5.14 percent is consistent with the level of the First Settlement Rate Increase. Consistent with the level of the Second Settlement Rate Increase, the parties agreed that Atmos Energy shall make an Advice Letter filing to reflect a 4.06 percent GRSA proposed to become effective on March 1, 2014. Both GRSAs shall continue to be subject to the refund conditions set forth in Advice Letter Nos. 497, 505, and 506. Both Settlement Rate Increases went into effect as interim rates so that if the Settlement Rate Increases are approved without modification, the refund conditions will not be applicable.

36. The parties agreed with the proposed modifications to Atmos Energy tariff sheets R18 (regarding Interruptible customers), R25 (regarding construction allowances), sheet 23 (deleting an unnecessary footnote), and sheets 27 and 28 (regarding the elimination of the AMIS).

37. The Parties agreed that Atmos Energy shall utilize the depreciation rates set forth in the 2010 SSU (Shared Services Unit) Depreciation Rate Study attached to the Direct Testimony and Exhibits of Mr. John C. Johnson. The Parties also agreed that the depreciation rates for the remaining rate base assets are as approved in Proceeding No. 09AL-507G.

38. Atmos Energy committed to apply for a Certificate of Public Convenience and Necessity for the Greeley Building Project, the Canon City Building Project, and the Salida and Gunnison Building Project prior to commencing construction.

39. Notwithstanding Atmos Energy's agreement in this case not to move forward with a multiyear plan, Atmos Energy reserved the right to seek deferred accounting treatment, new rate riders, or other alternative regulatory mechanisms to recover the costs associated with the building projects and Atmos Energy's SSIP. Neither Staff, the OCC, nor EOC agreed to any position regarding any such future filing.

40. Finally, the parties agreed that Atmos Energy shall use the specific regulatory principles reflected in the Settlement Agreement for purposes of Atmos Energy's Annual Reports, Appendix A, and GCA calculations.

III. REGULATORY PRINCIPLES

41. Under §§ 40-3-101 and 102, C.R.S., it is the Commission's duty to ensure that all rates charged by public utilities, such as Atmos Energy, are just and reasonable. The Commission's determination as to what is a fair, just, and reasonable rate is a matter of discretion. *Consumer Counsel v. P.U.C.,* 786 P.2d 1086 (Colo. 1990). In exercising this discretion, the Commission's findings and conclusions must be based on substantial evidence.

See Pub. Serv. Co. of Colo. v. Trigen-Nations Energy Co., 982 P.2d 316, 322 (Colo. 1999) (*en banc*).

42. The Commission must exercise reasoned judgment in setting rates. Ratemaking is a legislative function (*City and County of Denver v. Public Utilities Commission*, 129 Colo. 41, 266 P.2d 1105 (1954)) and not an exact science (*Public Utilities Commission v. Northwest Water Corporation*, 168 Colo. 154, 551 P.2d 266 (1963)). As a consequence, the Commission "may set rates based on the evidence as a whole" and "need not base its decision on specific empirical support in the form of a study or data." *Colorado Office of Consumer Counsel v. Colorado Public Utilities Commission*, 275 P.3d 656, 660 (Colo. 2012).

43. Under the just and reasonable standard, the Commission has the primary responsibility for balancing "the investor's interest in avoiding confiscation and the consumer's interest in prevention of exorbitant rates" (*Colorado Municipal League v. Public Utilities Commission*, 687 P.2d 416, 418 (Colo. 1984)) and for setting rates that "protect both (1) the right of the public utility company and its investors to earn a return reasonably sufficient to maintain the utility's financial integrity; and (2) the right of consumers to pay a rate which accurately reflects the cost of service rendered." *Public Service Company of Colorado v. Public Utilities Commission*, 644 P.2d 933, 939 (Colo. 1982). The utility's right to earn a reasonable return incorporates the principle that the Commission-authorized rate of return (ROR) is a return that the utility has a reasonable opportunity to realize and is not an ROR that the utility is guaranteed to realize.

44. In the context of ratemaking, the Colorado Supreme Court recently "reiterated that 'it is the result reached, not the method employed, which determines whether a rate is just and reasonable.'" *Glustrom v. Colorado Public Utilities Commission*, 280 P.3d 662, 669 (Colo. 2012), quoting *Colorado Ute Electric Association, Inc. v. Public Utilities Commission*, 198 Colo. 534, 602 P.2d 861, 864 (Colo. 1979) (citing *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944)).

45. Furthermore, it is recognized that "[t]he public and judicial policies in Colorado" favor settlement. *Colorado Ins. Guar. Ass'n v. Harris*, 872 P.2d 1139, 1142 (Colo. 1992) (*en banc*) (citing *Davis v. Flatiron Materials Co.*, 511 P.2d 28, 32 (Colo. 1973). All of the Parties support approval of the Settlement Agreement without modification. The undersigned ALJ finds that the Settlement Agreement represents a just, equitable, and reasonable resolution of issues that were contested among the Parties in this proceeding. The Settlement Agreement should be and will be accepted as filed and without modification.

IV. CONCLUSION

46. Based on the record in this proceeding, including the testimony, attachments, and Settlement Agreement, the ALJ finds that the terms, conditions, and rates contained in the Settlement Agreement comport with Commission standards.

47. The ALJ further finds that the terms, conditions, and rates contained in the Settlement Agreement are just and reasonable and in the public interest. Approval of the Settlement Agreement is in the public interest and will result in just and reasonable rates consistent with §§ 40-3-101 and 102, C.R.S. The compromises agreed to by each of the Settling Parties as well as the testimony in support of the terms of the Settlement Agreement provide a strong basis to find that the terms of the Settlement Agreement are in the public interest.

Therefore, the terms and conditions of the Settlement Agreement will be approved and adopted without modification.

48. In accordance with § 40-6-109(2), C.R.S., it is recommended that the Commission enter the following order.

V. ORDER

A. The Commission Orders That:

1. The Settlement Agreement filed on January 15, 2014 by Atmos Energy Corporation (Atmos Energy), Staff of the Public Utilities Commission, Energy Outreach Colorado, and the Colorado Office of Consumer Counsel (attached to this Decision as **Appendix** A) is admitted into evidence in this proceeding.

2. All pre-filed testimony and attachments thereto, as corrected on February 5, 2014, are admitted into evidence in this proceeding.

3. The tariff sheets filed on May 8, 2013 with Advice Letter No. 497, as amended on May 9, 2013, are permanently suspended.

4. The Settlement Agreement filed on January 15, 2014 is approved in its entirety and without modification.

5. Atmos Energy shall make a compliance Advice Letter filing to implement the rates set forth in the Settlement Agreement on Attachment 2 (Proof of Rates) (page 25 of Attachment A) and to discontinue the GRSA on not less than two business days' notice. The advice letter and tariff shall be filed as a new advice letter proceeding. In calculating the proposed effective date, the date the filing is received at the Commission is not included in the notice period and the entire notice period must expire prior to the effective date.

The advice letter and tariff must comply in all substantive respects to this Decision in order to be filed as a compliance filing on shortened notice.

6. The Settlement Agreement being approved without modification, the refund conditions set forth in Commission Decision Nos. R13-1022-I, R13-1583-I, and R14-0075-I are no longer applicable.

7. Within 60 days following the effective date of this Decision, Atmos Energy shall file a final reconciliation of the Advanced Metering Infrastructure Surcharge through the end of 2013 as well as a proposed mechanism, if necessary, to account for any over or under collected amounts that exist.

8. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

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

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

b) If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the administrative law judge and the parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

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

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

G. HARRIS ADAMS

Administrative Law Judge

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

No. C13-0620, the Commission suspended Advice Letter No. 497 until October 9, 2013, and referred the matter to an Administrative Law Judge ("ALJ") for a Recommended Decision.

3. Interventions in this Proceeding were filed by Staff, EOC, the OCC, and Public Service Company of Colorado ("PSCo"). Decision No. R13-1022-I, issued on August 19, 2013, granted the interventions, further suspended the effective date of Advice Letter No. 497 until January 1, 2014, established a procedural schedule, and approved an across-the-board General Rate Schedule Adjustment ("GRSA") of 12.85 percent to be placed in effect on January 1, 2014 subject to a refund condition. Decision No. R13-1583-I, issued on December 24, 2013, modified Decision No. R13-1022-I to reflect a GRSA of 5.14 percent to go into effect on January 1, 2014. On December 26, 2013, Atmos Energy filed Advice Letter No. 506 with its accompanying tariff sheets to reflect the 5.14 percent GRSA in Docket No. 13AL-1377G and such went into effect on January 1, 2014 pursuant to Commission Decision No. R13-1583-I.

4. Decision No. R13-1301-I, issued on October 17, 2013, modified the procedural schedule by providing additional time in the schedule for the intervenors to file Answer Testimony. On November 12, 2013, Staff, EOC, and OCC filed Answer Testimony. On December 2, 2013, PSCo withdrew its Intervention in this Proceeding.

5. On December 20, 2013, Atmos Energy, Staff and EOC filed a Stipulation and Settlement Agreement. Decision No. R13-1593-I, issued December 24, 2013, modified the procedural schedule to permit the filing of testimony in support of the Stipulation and Settlement Agreement.

6. On January 8, 2014, Atmos Energy filed Rebuttal Testimony. On January 8, 2014, Atmos Energy, Staff, and EOC filed Direct Testimony in support of the Stipulation and Settlement Agreement.

7. Through a series of negotiations, the Settling Parties arrived at this replacement Stipulation which resolves all of the issues that were raised by the Settling Parties in this Proceeding. This Stipulation replaces and supersedes the Stipulation and Settlement Agreement between Atmos Energy, Staff and EOC which was filed on December 20, 2013.

Settlement Terms and Conditions

8. The Settling Parties agree that Atmos Energy should be authorized a rate increase in annual base revenues consisting of two steps. Regarding the first step, for January through February 2014 Atmos Energy should be authorized an increase in annual base revenues of $1,644,000 ("First Settlement Rate Increase"). Regarding the second step, for the period of March 1, 2014 onwards, the authorized annual base revenue of $1,644,000 discussed in the first step should be reduced by $344,000 and Atmos Energy should be authorized an increase in annual base revenues of $1,300,000 ("Second Settlement Rate Increase"). Attachment 1 provides the calculations supporting the First Settlement Rate Increase and Attachment 2 provides the calculations supporting the Second Settlement Rate Increase ("Attachments").

9. To calculate both Settlement Rate Increases, the Settling Parties utilized a historic test period of the twelve months ending December 31, 2012 (the "Settlement Test Period") and calculated the Settlement Test Period Rate Base using the 13-month average methodology.

10. Both Settlement Rate Increases utilize a rate of return on equity of 9.72 percent and a weighted average cost of capital of 8.07 percent. The rate of return calculations are set forth in greater detail on the Attachments (Schedule 2 Return on Rate Base). The Settling Parties agree that Atmos Energy's authorized rate of return on equity going forward shall be any rate of return on equity within the range of 9.5 percent to 10 percent.

11. The Settling Parties agree that both Settlement Rate Increases include the revenue impact of including all of Atmos Energy's per book investments in Advanced Metering Infrastructure ("AMI") as of December 31, 2012 in base rates rather than reflecting these costs in a separate rate rider. In conjunction with the implementation of interim GRSA rates on January 1, 2014, Atmos Energy set the AMI surcharge ("AMIS") at $0.00. As part of the compliance filing following approval of the Stipulation, Atmos Energy will discontinue the existing AMIS. Within 60 days following the final approval of the Stipulation, Atmos Energy will file a final reconciliation of the AMIS through the end of 2013 as well as a proposed mechanism, if necessary, to account for any over or under collected amounts that may exist.

12. The Settling Parties agree that both Settlement Rate Increases reflect the inclusion of average gas storage inventory costs during the Settlement Test Period in base rates as proposed by Atmos Energy rather than reflecting these costs in Atmos Energy's Gas Cost Adjustment ("GCA") mechanism. However, Staff, EOC and the OCC specifically reserve the right to argue in a future proceeding that a different treatment of gas storage costs is appropriate.

13. Both Settlement Rate Increases reflect adjustments to the Company's filed Operations and Maintenance Expense. Specifically:

a. The Settling Parties agree that authorized rate case expenses should be reduced by $100,000 (from $450,000 to $350,000) and amortized over three years. This adjustment does not specifically accept or reject any particular adjustment or regulatory principle proposed by any of the parties to this proceeding.

b. The Settling Parties accept Atmos Energy's proposal to include $333,333 in the revenue requirement in this case as a known and measurable adjustment to the Settlement Test Period expenses associated with Atmos Energy's data integration project which will convert Atmos Energy's historic records of its pipeline system into a geo-coded digital format. Without agreeing to the prudence of specific future expenditures for this project, the Settling Parties agree that the data integration project is reasonable and should proceed forward.

c. The Settling Parties agree to a negative adjustment to the revenue requirement in this case to reflect imputed cost savings associated with Atmos Energy's AMI program. Atmos Energy's filing included $310,741 in AMI savings in the historic test period which decrease the proposed overall revenue requirement. In the First Settlement Rate Increase calculation, those imputed savings are increased by $289,259 to a total of $600,000 in the Settlement Test Period. In the Second Settlement Rate Increase calculation, those imputed savings are increased by an additional $344,000 to a total of $944,000 in the Settlement Test Period. These adjustments do not specifically accept or reject any particular adjustment or regulatory principle proposed by any of the parties to this proceeding.

d. The Settling Parties further agree to a negative adjustment of $107,330 to the revenue requirement in this case. This adjustment does not specifically accept or reject any particular adjustment or regulatory principle proposed by any of the parties to this proceeding.

e. The Settlement Test Period Operation and Maintenance Expense adjustments are set forth in greater detail on the Attachments (Schedule 3 Adjustments to Operation and Maintenance Expense).

14. Both Settlement Rate Increases reflect the Settling Parties agreement with respect to the Settlement Test Period Rate Base. Specifically:

a. The Settling Parties agree, except for the OCC who does not contest, that Atmos Energy's investments in the statewide AMI deployment are reasonable and prudent. Therefore, both Settlement Rate Increases reflect the inclusion of the per book AMI investments as of December 31, 2012 in the Settlement Test Period Rate Base.

b. Both Settlement Rate Increases also reflect the inclusion of Atmos Energy's gas storage costs in Rate Base as discussed in Paragraph 10 above.

c. The Settling Parties agree to remove from Rate Base the post-test period changes in net plant in service that were proposed by Atmos Energy.

d. The Rate Base agreement and adjustments are set forth in greater detail on the Attachments (Schedule 4 Adjustments to Rate Base).

15. Both Settlement Rate Increases are proposed to be implemented in customer rates as follows:

a. The Settling Parties agree to a Residential monthly Facilities Charge of $10.75. With respect to the other customer classes, the Settling Parties agree to the monthly Facilities Charges reflected in the Attachments (Proof of Rates).

b. The Settling Parties agree to utilize Atmos Energy's filed Class Cost of Service Study to calculate each customer class' revenue requirement and the Distribution System Rates for each customer class.

c. The Settling Parties agree to maintain Atmos Energy's four separate GCA rate areas.

d. The specific rate changes that would result from this Stipulation are set forth in greater detail on the Attachments (Proof of Rates). Upon approval of this Stipulation, Atmos Energy will make a compliance Advice Letter filing to implement the rates set forth on Attachment 2 and to discontinue the GRSA. To the extent a Commission Decision approving this Stipulation is issued with sufficient time to allow Atmos Energy to place the approved rates into effect prior to March 1, 2014, Atmos Energy will withdraw its interim 4.06 percent GRSA rate and discontinue the GRSA.

e. Pursuant to Commission Decision No. R13-1583-I, Advice Letter No. 506 implementing a GRSA of 5.14 percent went into effect on January 1, 2014. The GRSA of 5.14 percent is consistent with the level of the First Settlement Rate Increase. Consistent with the level of the Second Settlement Rate Increase, the Settling Parties agree that Atmos Energy shall make an Advice Letter filing to reflect a 4.06 percent GRSA proposed to become effective on March 1, 2014. Both GRSAs shall continue to be subject to the refund conditions set forth in

Advice Letter Nos. 497, 505 and 506. The Settling Parties' intent is to reflect both Settlement Rate Increases in interim rates so that if the Settlement Rate Increases are approved without modification, the refund conditions will not be applicable.

16. The Settling Parties agree with the proposed modifications to Atmos Energy tariff sheets R18 (regarding Interruptible customers), R25 (regarding construction allowances), sheet 23 (deleting an unnecessary footnote), and sheets 27 and 28 (regarding the elimination of the AMIS).

17. The Settling Parties agree that Atmos Energy shall utilize the depreciation rates set forth in the 2010 SSU ("Shared Services Unit") Depreciation Rate Study attached to the Direct Testimony and Exhibits of Mr. John C. Johnson. The Settling Parties agree that the depreciation rates for the remaining rate base assets are as approved in Docket No. 09AL-507G.

18. Atmos Energy commits to apply for a Certificate of Public Convenience and Necessity ("CPCN") for the Greeley Building Project, the Canon City Building Project, and the Salida and Gunnison Building Project prior to commencing construction.

19. Notwithstanding Atmos Energy's agreement in this case not to move forward with a multiyear plan, Atmos Energy reserves the right to seek deferred accounting treatment, new rate riders, or other alternative regulatory mechanisms to recover the costs associated with the building projects and Atmos Energy's System Safety and Integrity Project. Neither Staff, the OCC, nor EOC agree to any position regarding any such future filing.

20. The Settling Parties agree that Atmos Energy shall use the specific regulatory principles reflected in this Stipulation for purposes of Atmos Energy's Annual Reports, Appendix A, and GCA calculations.

General Terms and Conditions

21. The Settling Parties agree that this Stipulation is in the public interest and will be supported by the Settling Parties' testimony and/or statements of counsel in this proceeding. The Settling Parties agree to support this Stipulation as being in the public interest in proceedings before the Commission and to advocate in good faith that the Commission approve this Stipulation in its entirety.

22. The Settling Parties agree that this Stipulation represents a compromise in the positions of all Settling Parties and has been negotiated as a packaged settlement. As such, the Settling Parties acknowledge that their support and advocacy of the Stipulation is based upon the Stipulation as a whole and not based upon its individual components viewed in isolation. Additionally, evidence of conduct or statements made in the negotiation and discussion phases of this Stipulation will not be admissible as evidence in any proceeding before the Commission or any court.

23. The Settling Parties agree that all negotiations relating to this Stipulation are privileged and confidential, and in addition, that no party will be bound by any position asserted in the negotiations, except to the extent expressly stated in this Stipulation.

24. The Settling Parties agree that except as otherwise expressly noted in this Stipulation: (a) the execution of this Stipulation will not be deemed to constitute an acknowledgment of any Settling Party of the validity or invalidity of any particular method,

theory or principle of ratemaking or regulation, and no Settling Party will be deemed to have agreed that any principle, method or theory of regulation employed in arriving at this Stipulation is appropriate for resolving any issue in any other proceeding; (b) the execution of the Stipulation will not constitute the basis of estoppel or waiver in future proceedings by any Settling Party; and (c) no Settling Party will be deemed to be bound by any position asserted by any other Settling Party, and no finding of fact or conclusion of law other than those expressly stated will be deemed to be implicit in this Stipulation. Any specific reservation of future litigation rights contained in the Stipulation should not be deemed to waive the applicability of this general reservation of litigation rights in future proceedings as to all matters contained in the Stipulation.

25. The Settling Parties agree to the admission of all pre-filed testimony and exhibits filed in Proceeding No. 13AL-0496G, as corrected on February 5, 2014. The Settling Parties waive cross examination on such pre-filed testimony and exhibits.

26. The Settling Parties acknowledge that their support and advocacy of the Stipulation may be compromised by material alterations thereto. In the event the Commission rejects or materially alters the Stipulation, the Settling Parties agree that within seven days of such Commission Decision any Settling Party may provide notice to the other Settling Parties of its objection to the Stipulation as modified. Upon such objection, the Settling Parties will no longer be bound by its terms and will not be deemed to have waived any of their respective procedural or due process rights under Colorado law. If a Settling Party objects to the Stipulation as modified, it may withdraw from the Stipulation and proceed with its case by filing a notice of withdrawal with the Commission and in accordance with procedures established by the Commission at such time.

27. If the Commission chooses to adopt and approve the Stipulation, this Stipulation resolves all disputed matters relative to this proceeding between the Settling Parties. Any disputed matters will be deemed resolved to the extent that the Stipulation is not compromised by material alterations.

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

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

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

BASED ON THE FOREGOING, the Settling Parties respectfully request that the Commission issue an Order approving this Stipulation and adopting the terms and conditions of this Stipulation.

DATED this 15th day of January, 2014.

RESPECTFULLY SUBMITTED,

ATMOS ENERGY CORPORATION

By: ______________________
Karen P. Wilkes,
Vice President, Regulatory & Public Affairs
Atmos Energy Corporation
1555 Blake Street, Suite 400
Denver, CO 80202
karen.wilkes@atmosenergy.com

HOLLAND & HART LLP

____
Thorvald A. Nelson, #24715
Emanuel T. Cocian, #36562
Holland & Hart LLP
6380 South Fiddlers Green Circle, Suite 500
Greenwood Village, CO 80111
Telephone: (303) 290-1601
tnelson@hollandhart.com
etcocian@hollandhart.com

ATTORNEYS FOR
ATMOS ENERGY CORPORATION

TRIAL STAFF OF THE COLORADO
PUBLIC UTILITIES COMMISSION

By:____________________

Charles B. Hernandez, CPA
Colorado Public Utilities Commission
Chief Economist, Energy and Water
1560 Broadway, Suite 250
Denver, Colorado 80202
Charles.hernandez@state.co.us

____

David M. Nocera, #28776
Scott C. Dunbar, #44521
Ralph L. Carr Colorado Judicial Center
1300 Broadway, 8th Floor
Denver, Colorado 80203
Tel: (720) 508-6333
Fax: (720) 508-6038
Dave.nocera@state.co.us
Scott.dunbar@state.co.us

ATTORNEYS FOR TRIAL STAFF

ENERGY OUTREACH COLORADO

By:____________________

Skip Arnold, Executive Director
Energy Outreach Colorado
225 E. 16th Avenue, Suite 200
Denver, Colorado 80203
sarnold@energyoutreach.org

____

Jeffrey G. Pearson, # 5874
Jeffrey G. Pearson, LLC
1570 Emerson Street
Denver, CO 80218
Tel: 303.618.0686
Fax: 303.837.1557
Jpearson @jgp-law.com

ATTORNEY FOR ENERGY OUTREACH COLORADO

COLORADO OFFICE OF CONSUMER COUNSEL

By:______________________

Cory W. Skluzak
Financial Analyst
Office of Consumer Counsel
1560 Broadway, Suite 200
Denver, CO 80202

____

Gregory E. Bunker, #24111
Stephen W. Southwick, #30389
Office of the Attorney General
1300 Broadway, 7th Floor
Denver, CO 80203
Tel: (720) 508-6212
Gregory.Bunker@state.co.us

ATTORNEYS FOR THE COLORADO
OFFICE OF CONSUMER COUNSEL

Schedule 1 - Revenue Requirement

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.		Company Filed with End of Year Rate Base HTY - EOP RB	Company Filed with Average Rate Base HTY-13 Avg RB	Staff Adjustments	Staff Filed	Settlement Adjustments	Settlement
1	Revenue at Present Rates (Normalized)	85,601,417	85,601,417	470,547	86,071,964	(470,547)	85,601,417
2	Cost of Gas (Normalized & Adjusted)	51,775,138	51,775,138	363,883	52,139,021	(363,883)	51,775,138
3	Operations and Maintenance Expense	13,799,563	13,799,563	(172,592)	13,626,971	(257,330)	13,369,641
4	Depreciation and Amortization Expense	8,112,178	8,112,178	(693,761)	7,418,417	228,126	7,646,543
5	Taxes Other Than Income Taxes	2,265,142	2,265,142		2,265,142	0	2,265,142
6	AFUDC	(10,337)	(10,337)	1,961	(8,376)	(1,961)	(10,337)
7	Total	75,941,684	75,941,684	(864,392)	75,441,175		75,046,127
8							
9	Rate Base	110,926,902	107,802,543	(5,915,652)	101,886,891	5,267,394	107,154,285
10							
11	Return on Rate Base	8.48%	8.48%		7.91%		8.07%
12							
13	Required Earnings	9,401,055	9,136,266		8,056,197		8,647,351
14							
15	Income Taxes	3,754,876	3,649,116		3,090,229		3,353,929
16	Taxable Trust - After Tax	198,010	198,010		198,010		198,010
17							
18	Revenue Requirement	89,295,625	88,925,076		86,785,611		87,245,417
19							
21	Revenue Increase/(Decrease)	3,694,208	3,323,659		713,647		1,644,000

Schedule 2 - Return on Rate Base

Line No.	(a)	(b)	(c)	(d)
1	**Company Filed**		Average	Wtd Ave
2		Ratio	Cost	Cost
3	Long Term Debt	47.43%	6.230%	2.96%
4	Equity	52.57%	10.50%	5.52%
5	Weighted Cost of Capital			8.475%
6				
7	Combined Marginal Tax Rate			38.01%
8	Pretax Weighted Cost of Capital			11.86%
9				
10	**Staff Filed**			
11			Average	Wtd Ave
12		Ratio	Cost	Cost
13	Long Term Debt	47.430%	6.230%	2.955%
14	Equity	52.570%	9.420%	4.952%
15				7.907%
16				
17	Combined Marginal Tax Rate			38.01%
18	Pretax Weighted Cost of Capital			10.94%
19				
20	**Settlement**		Average	Wtd Ave
21		Ratio	Cost	Cost
22	Long Term Debt	47.432%	6.23%	2.96%
23	Equity	52.568%	9.72%	5.11%
24				8.07%
25				
26	Combined Marginal Tax Rate			38.01%
27	Pretax Weighted Cost of Capital			11.20%

Schedule 3 - Adjustments to Operation and Maintenance Expense

Line No.	(a)	(b) Company Filed	(c) Staff Adjustments	(d) Staff Filed	(e) Settlement Adjustments	(f) Settlement
1	Total Operation and Maintenance Expenses - Unadjusted	13,170,838		13,170,838		13,170,838
2						
3	Adjustments to Operation & Maintenance Expenses					
4						
5	Salaries	124,658		124,658		124,658
6	Benefits	368,964		368,964		368,964
7	Allocation of Adjusted General Office Costs	1,147		1,147		1,147
8	Promotional and Advertising Exclusions	(24,490)		(24,490)		(24,490)
9	Interest on Customer Deposits	9,076		9,076		9,076
10	Adjust Uncollectible Expense to the Level of Normalized Sales Revenue	(869)		(869)		(869)
11	Adjust Test Year Uncollectibles	63,495		63,495		63,495
12	Rate Case Expense	150,000	(150,000)	-	116,667	$ 116,667
13	Expense Report Adjustments	(85,848)		(85,848)		(85,848)
14	Data Integration Adjustment	333,333	(333,333)	-	333,333	333,333
15	AMI Savings Adjustment	(310,741)	310,741	-	(600,000)	(600,000)
16	Consolidated O&M Reflecting Staff/OCC Adjustments				(107,330)	(107,330)
17	Total Adjustments	628,725	(172,592)	456,133		198,803
18						
19	Total Adjusted Operation and Maintenance Expenses	13,799,563		13,626,971		13,369,641
20						
21	Source: Exhibit JTC-12, Schedule 4					

Schedule 4 - Adjustments to Rate Base

Line No.	(a)	(b) Company Filed (1)	(c) Staff Adjustments	(d) Staff Filed	(e) Settlement Adjustments	(f) Settlement
1	Average Rate Base					
2	Plant in Service	201,194,736	(3,242,628)	197,952,108	3,242,628	201,194,736
3	Accumulated Depreciation	(82,291,931)	239,801	(82,052,130)	(239,801)	(82,291,931)
4	Net Plant	118,902,805		115,899,978	3,002,827	118,902,805
5	Work in Progress	5,407,823	(1,025,932)	4,381,891	1,025,932	5,407,823
6	Average Storage Gas	2,562,416	(2,562,416)	-	2,562,416	2,562,416
7	Accumulated Deferred Income Taxes	(14,909,205)	1,327,964	(13,581,241)	(1,327,964)	(14,909,205)
8	Customer Advances for Construction	(1,691,852)		(1,691,852)	-	(1,691,852)
9	Customer Deposits	(2,669,360)		(2,669,360)	-	(2,669,360)
10	Prepaid Pension Expense	1,564,884		1,564,884	-	1,564,884
11	Working Capital:					
12	Prepayments	755,316		755,316	-	755,316
13	Cash Requirements	(2,772,725)		(2,772,725)	4,183	(2,768,542)
14	Adjustment for Known and Measurable					
15	Changes in Net Plant In Service	652,441	(652,441)	-		
16	Total Average Rate Base	107,802,543	(5,915,652)	101,886,891		107,154,285
17						
18	(1) Source: Exhibit JTC-12, Schedule 8 Average Rate Base					

Settlement Proof of Rates

Atmos Energy Corp. - Colorado Service Areas
Summary of Revenue at Present Rates
Twelve Months Ended December 31, 2012

Line No.	Description	Number of Bills	Volume Ccf Average 14.65 psi	Adjustments to Bills	Adjustments to Volume Ccf	Total Bills	Total Volumes	Adjusted Customer Charge	Adjusted Commodity Charge	Adjusted Present Base Revenue	Adjusted Gas Cost Revenues	Adjusted Present Total Revenue	Settlement Customer Charge	Settlement Commodity	Settlement Revenue	Increase By Class
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
1	Residential	1,190,903	67,285,221	(17,589)	5,604,696	1,173,314	72,889,917	$ 10.00	$ 0.14385	$ 22,218,355	$ 31,351,263	$ 53,569,618	$ 10.75	$ 0.16301	$ 55,846,174	2,276,556
2	Commercial	143,918	44,265,498	(1,409)	3,021,596	142,509	47,287,094	24.00	0.11242	8,736,231	20,351,818	29,088,049	$ 25.00	$ 0.10048	28,665,950	(422,099)
3	Irrigation	69	90,932	(1)	0	68	90,932	40.00	0.09444	11,308	37,998	49,306	$ 40.00	$ 0.09250	49,129	(177)
4																
5	Total Colorado Sales Revenue	1,334,890	111,641,652	(18,999)	8,626,292	1,315,891	120,267,944			$ 30,965,894	$ 51,741,079	$ 82,706,973			$ 84,561,253	1,854,280
6																
7	Transportation Revenues															
8	Max Rate - Commercial	1,446	7,047,460	42	532,170	1,488	7,579,630	34	0.11242	$ 902,694		$ 902,694	$ 75.00	$ 0.08220	$ 734,646	(168,048)
9	Max Rate - Industrial	41	830,790	7	246,260	48	1,077,050	275	0.11242	134,282		134,282	$ 75.00	$ 0.08220	$ 92,134	(42,148)
10	Special Contract	2,597	51,562,320	7	-	2,604	51,562,320			1,525,944	$ 34,059	1,560,004			1,560,004	-
11	Transportation and Other	4,084	59,440,570	56	778,430	4,140	60,219,000			$ 2,562,920	$ 34,059	$ 2,596,980			$ 2,386,783	(210,197)
12																
13	Other Revenues									$ 297,465		$ 297,465			$ 297,465	0
14																
15	Total Colorado Revenue									$ 33,826,279	$ 51,775,138	$ 85,601,417			$ 87,245,501	$ 1,644,083

Schedule 1 - Revenue Requirement

Line No.	(a)	(b) Company Filed with End of Year Rate Base HTY - EOP RB	(c) Company Filed with Average Rate Base HTY-13 Avg RB	(d) Staff Adjustments	(e) Staff Filed	(f) Settlement Adjustments	(g) Settlement
1	Revenue at Present Rates (Normalized)	85,601,417	85,601,417	470,547	86,071,964	(470,547)	85,601,417
2	Cost of Gas (Normalized & Adjusted)	51,775,138	51,775,138	363,883	52,139,021	(363,883)	51,775,138
3	Operations and Maintenance Expense	13,799,563	13,799,563	(172,592)	13,626,971	(601,330)	13,025,641
4	Depreciation and Amortization Expense	8,112,178	8,112,178	(693,761)	7,418,417	228,126	7,646,543
5	Taxes Other Than Income Taxes	2,265,142	2,265,142		2,265,142	0	2,265,142
6	AFUDC	(10,337)	(10,337)	1,961	(8,376)	(1,961)	(10,337)
7	Total	75,941,684	75,941,684	(864,392)	75,441,175		74,702,127
8							
9	Rate Base	110,926,902	107,802,543	(5,915,652)	101,886,891	5,267,394	107,154,285
10							
11	Return on Rate Base	8.48%	8.48%		7.91%		8.07%
12							
13	Required Earnings	9,401,055	9,136,266		8,056,197		8,647,351
14							
15	Income Taxes	3,754,876	3,649,116		3,090,229		3,353,929
16	Taxable Trust - After Tax	198,010	198,010		198,010		198,010
17							
18	Revenue Requirement	89,295,625	88,925,076		86,785,611		86,901,417
19							
21	Revenue Increase/(Decrease)	3,694,208	3,323,659		713,647		1,300,000

Schedule 2 - Return on Rate Base

Line No.	(a)	(b)	(c)	(d)
1	**Company Filed**		Average	Wtd Ave
2		Ratio	Cost	Cost
3	Long Term Debt	47.43%	6.230%	2.96%
4	Equity	52.57%	10.50%	5.52%
5	Weighted Cost of Capital			8.475%
6				
7	Combined Marginal Tax Rate			38.01%
8	Pretax Weighted Cost of Capital			11.86%
9				
10	**Staff Filed**			
11			Average	Wtd Ave
12		Ratio	Cost	Cost
13	Long Term Debt	47.430%	6.230%	2.955%
14	Equity	52.570%	9.420%	4.952%
15				7.907%
16				
17	Combined Marginal Tax Rate			38.01%
18	Pretax Weighted Cost of Capital			10.94%
19				
20	**Settlement**		Average	Wtd Ave
21		Ratio	Cost	Cost
22	Long Term Debt	47.432%	6.23%	2.96%
23	Equity	52.568%	9.72%	5.11%
24				8.07%
25				
26	Combined Marginal Tax Rate			38.01%
27	Pretax Weighted Cost of Capital			11.20%

Schedule 3 - Adjustments to Operation and Maintenance Expense

Line No.	(a)	(b) Company Filed	(c) Staff Adjustments	(d) Staff Filed	(e) Settlement Adjustments	(f) Settlement
1	Total Operation and Maintenance Expenses - Unadjusted	13,170,838		13,170,838		13,170,838
2						
3	Adjustments to Operation & Maintenance Expenses					
4						
5	Salaries	124,658		124,658		124,658
6	Benefits	368,964		368,964		368,964
7	Allocation of Adjusted General Office Costs	1,147		1,147		1,147
8	Promotional and Advertising Exclusions	(24,490)		(24,490)		(24,490)
9	Interest on Customer Deposits	9,076		9,076		9,076
10	Adjust Uncollectible Expense to the Level of Normalized Sales Revenue	(869)		(869)		(869)
11	Adjust Test Year Uncollectibles	63,495		63,495		63,495
12	Rate Case Expense	150,000	(150,000)	-	116,667	$ 116,667
13	Expense Report Adjustments	(85,848)		(85,848)		(85,848)
14	Data Integration Adjustment	333,333	(333,333)	-	333,333	333,333
15	AMI Savings Adjustment	(310,741)	310,741	-	(944,000)	(944,000)
16	Consolidated O&M Reflecting Staff/OCC Adjustments				(107,330)	(107,330)
17	Total Adjustments	628,725	(172,592)	456,133		(145,197)
18						
19	Total Adjusted Operation and Maintenance Expenses	13,799,563		13,626,971		13,025,641
20						
21	Source: Exhibit JTC-12, Schedule 4					

Schedule 4 - Adjustments to Rate Base

Line No.	(a)	(b) Company Filed (1)	(c) Staff Adjustments	(d) Staff Filed	(e) Settlement Adjustments	(f) Settlement
1	Average Rate Base					
2	Plant in Service	201,194,736	(3,242,628)	197,952,108	3,242,628	201,194,736
3	Accumulated Depreciation	(82,291,931)	239,801	(82,052,130)	(239,801)	(82,291,931)
4	Net Plant	118,902,805		115,899,978	3,002,827	118,902,805
5	Work in Progress	5,407,823	(1,025,932)	4,381,891	1,025,932	5,407,823
6	Average Storage Gas	2,562,416	(2,562,416)	-	2,562,416	2,562,416
7	Accumulated Deferred Income Taxes	(14,909,205)	1,327,964	(13,581,241)	(1,327,964)	(14,909,205)
8	Customer Advances for Construction	(1,691,852)		(1,691,852)	-	(1,691,852)
9	Customer Deposits	(2,669,360)		(2,669,360)	-	(2,669,360)
10	Prepaid Pension Expense	1,564,884		1,564,884	-	1,564,884
11	Working Capital:					
12	Prepayments	755,316		755,316	-	755,316
13	Cash Requirements	(2,772,725)		(2,772,725)	4,183	(2,768,542)
14	Adjustment for Known and Measurable					
15	Changes in Net Plant In Service	652,441	(652,441)	-		
16	Total Average Rate Base	107,802,543	(5,915,652)	101,886,891		107,154,285
17						
18	(1) Source: Exhibit JTC-12, Schedule 8 Average Rate Base					

Docket No. 13AL-0496G
Stipulation and Settlement Agreement
Attachment 2
January 15, 2014

Settlement Proof of Rates

Atmos Energy Corp. - Colorado Service Areas
Summary of Revenue at Present Rates
Twelve Months Ended December 31, 2012

Line No.	Description	Number of Bills	Volume Ccf Average 14.65 psi	Adjustments to Bills	Adjustments to Volume Ccf	Total Bills	Total Volumes	Adjusted Customer Charge	Adjusted Commodity Charge	Adjusted Present Base Revenue	Adjusted Gas Cost Revenues	Adjusted Present Total Revenue	Settlement Customer Charge	Settlement Commodity	Settlement Revenue	Increase By Class
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
1	Residential	1,190,903	67,285,221	(17,589)	5,604,696	1,173,314	72,889,917	$ 10.00	$ 0.14385	$ 22,218,355	$ 31,351,263	$ 53,569,618	$ 10.75	$ 0.15957	$55,595,433	2,025,815
2	Commercial	143,918	44,265,498	(1,409)	3,021,596	142,509	47,287,094	24.00	0.11242	8,736,231	20,351,818	29,088,049	$ 25.00	$ 0.09868	28,580,833	(507,216)
3	Irrigation	69	90,932	(1)	0	68	90,932	40.00	0.09444	11,308	37,998	49,306	$ 40.00	$ 0.09124	49,015	(291)
4																
5	Total Colorado Sales Revenue	1,334,890	111,641,652	(18,999)	8,626,292	1,315,891	120,267,944			$ 30,965,894	$ 51,741,079	$ 82,706,973			$84,225,280	1,518,308
6																
7	<u>Transportation Revenues</u>															
8	Max Rate - Commercial	1,446	7,047,460	42	532,170	1,488	7,579,630	34	0.11242	$ 902,694		$ 902,694	$ 75.00	$ 0.08122	$ 727,218	(175,476)
9	Max Rate - Industrial	41	830,790	7	246,260	48	1,077,050	275	0.11242	134,282		134,282	$ 75.00	$ 0.08122	$ 91,078	(43,204)
10	Special Contract	2,597	51,562,320	7	-	2,604	51,562,320			1,525,944	$ 34,059	1,560,004			1,560,004	-
11	Transportation and Other	4,084	59,440,570	56	778,430	4,140	60,219,000			$ 2,562,920	$ 34,059	$ 2,596,980			$ 2,378,299	(218,680)
12																
13	Other Revenues									$ 297,465		$ 297,465			$ 297,465	0
14																
15	Total Colorado Revenue									$ 33,826,279	$ 51,775,138	$ 85,601,417			$86,901,044	$ 1,299,627

Decision No. R14-1027

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 14AL-0300G

IN THE MATTER OF ADVICE LETTER NO. 511 FILED BY ATMOS ENERGY CORPORATION TO PLACE INTO EFFECT TARIFF SHEET CHANGES TO BE EFFECTIVE ON MAY 5, 2014

RECOMMENDED DECISION OF ADMINISTRATIVE LAW JUDGE MELODY MIRBABA APPROVING STIPULATION AND SETTLEMENT AGREEMENT

Mailed Date: August 26, 2014

TABLE OF CONTENTS

I. STATEMENT

1. This matter comes before the Commission for consideration of the Stipulation and Settlement Agreement filed on August 8, 2014 (Settlement Agreement), in the above-captioned rate case proceeding initiated by Atmos Energy Corporation (Atmos Energy or the Company). The Settlement Agreement (including Attachments 1, 2, and 3 thereto), attached hereto as Appendix A, is signed by Atmos Energy, Trial Staff for the Public Utilities Commission of the State of Colorado (Staff), the Colorado Office of Consumer Counsel (OCC), and Energy Outreach Colorado, (EOC), (collectively, the Parties and individually a Party). The Settlement Agreement is unopposed.

2. Now being fully advised in the matter, and for the reasons and authorities set forth herein, the Administrative Law Judge (ALJ) finds that the resolution of this proceeding, as achieved by the Settlement Agreement, is just and reasonable, and in the public interest, and that the Settlement Agreement results in just and reasonable rates that are nondiscriminatory for the utility service provided by the Company in Colorado. For the reasons set forth below,

the ALJ approves the resolution of the proceeding as agreed to by the Parties and reflected in the Settlement Agreement, since it is consistent with the standards of § 40-3-101, C.R.S.

A. Procedural Background.

3. On April 2, 2014, Atmos Energy filed Advice Letter No. 511 (Advice Letter) to implement an increase in its gas base rates. Atmos Energy requested that the tariffs become effective on May 5, 2014. Atmos Energy filed Direct Testimony and Exhibits with the Advice Letter, proposing an increase to the Company's annual revenues by $4,847,370, or approximately 4.43 percent, based on the 12 months ended on December 31, 2013.

4. During its weekly meeting held April 30, 2014, the Commission referred this matter to an ALJ for disposition. Decision No. C14-0452. At the same time, the Commission suspended the proposed effective date of the tariff page(s) filed by Atmos Energy with the Advice Letter for 120 days until September 2, 2014, or until further order of the Commission. *Id.* The Commission ordered that anyone wishing to intervene in this proceeding file a motion to intervene with the Commission within 30 days after the mailing date of Decision No. C14-0452. The Decision was mailed on May 2, 2014. Interventions were due by June 1, 2014.

5. On May 9, 2014, the ALJ scheduled a prehearing conference in this matter to take place on June 5, 2014. Decision No. R14-0494-I. The same Decision further suspended the effective date of the tariff page(s) to December 1, 2014.

6. The OCC and Staff timely intervened of right. Staff and the OCC requested an evidentiary hearing on the Advice Letter and tariff sheets.

7. On May 14, 2014, EOC filed a Motion to Intervene, seeking permissive intervention in this proceeding. By Decision No. R14-0618-I, the ALJ granted EOC's Motion to Intervene.

8. On June 5, 2014, the prehearing conference was held. During the hearing, the Parties agreed to, and the ALJ approved, hearing dates, public comment hearing dates, and procedural deadlines. Decision No. R14-0618-I.

9. On June 17, 2014, Atmos Energy re-filed its Direct Testimony as Hearing Exhibits 2 through 13.

10. On July 8, 2014, Answer Testimony was submitted by Staff as Hearing Exhibits 100 through 104, the EOC as Hearing Exhibits 200 through 201, and the OCC as Hearing Exhibits 300 through 301. Additionally, the OCC submitted its Intervention as Hearing Exhibit 302.

11. On July 28, 2014, Atmos Energy submitted its Rebuttal Testimony as Hearing Exhibits 14 through 20. The Rebuttal Testimony of the Company resulted in a lowering of the requested revenue requirement increase from $4,847,370 to $4,431,533.

12. On July 30, 2014, the Parties participated in a settlement conference.

13. On August 1, 2014, EOC filed a "Motion to Strike Certain Rebuttal Testimony" (Motion to Strike).

14. On August 8, 2014, Atmos Energy, Staff, EOC, and the OCC filed the Settlement Agreement which resolved all of the issues that were raised by all of the Parties in this proceeding. Pursuant to the terms of the Settlement Agreement, the Parties agreed to the admission of all pre-filed testimony and exhibits filed in this proceeding and waived cross-examination on such pre-filed testimony and exhibits.

15. Simultaneously with the Settlement Agreement, Atmos Energy filed an "Unopposed Joint Motion to Approve Stipulation and Settlement Agreement, to Modify Procedural Schedule and For Waiver of Response Time" (Unopposed Joint Motion).

16. Decision No. R14-0976-I granted the Unopposed Joint Motion in part, vacating the remaining procedural deadlines, vacating the final prehearing conference, vacating the deadline to respond to EOC's Motion to Strike, vacating the hearing scheduled for August 13 and 15, 2014, but retaining the August 14, 2014 hearing date.

17. On August 14, 2014, the Parties appeared for an evidentiary hearing to provide testimony in support of the Settlement Agreement pursuant to Decision No. R14-0976-I. During the course of the hearing, the Parties provided additional testimony in support of the Settlement Agreement (Appendix A). In particular, Mr. Christian, Mr. Kunzie, Mr. Arnold, and Mr. Skluzak testified at the hearing.

18. During the course of the hearing, the following exhibits were admitted into evidence by administrative notice: Hearing Exhibits 2 through 22; Hearing Exhibits 100 through 104; Hearing Exhibits 200 through 201; and Hearing Exhibits 300 through 302, including all attachments to such Hearing Exhibits.[1] Hearing Exhibit 1 was also admitted into evidence, (but not by administrative notice).

II. PUBLIC COMMENTS

19. Based on its long-standing practice, the Commission invited public comment on the issues presented in this matter. The Commission believes that, although institutions such as the OCC represent the interests of certain consumers before the Commission, it is important to have a direct connection to interested and affected individuals and groups.

[1] With the exception of Hearing Exhibit 1, the electronic, pre-filed copies in the Commission's administrative record of all Hearing Exhibits were admitted by administrative notice. The fact administratively noticed is that the electronic pre-filed copy in the administrative record is the content of the otherwise admissible hearing exhibit.

20. In this Proceeding, the Commission received 53 written comments. The topics include general opposition to the increase, the poor economy and ratepayers' inability to pay for an increase, the difference in the proposed increase for residential customers versus commercial customers, and the low price of natural gas.

21. Two public comment hearings were held in this proceeding. On June 19, 2014, several people attended the Greeley public comment hearing although no one chose to speak. The second public comment hearing was held in Canon City on July 1, 2014, but no members of the public attended.

22. As is the Commission's practice, the ALJ read and considered the written comments from members of the public.

III. FINDINGS AND DISCUSSION

A. Summary of the Pre-Filed Testimony.

1. Atmos Energy

23. Along with its Advice Letter, Atmos Energy filed the direct testimony of seven witnesses, which are summarized below:

- Karen P. Wilkes: Introduced the Company's other witnesses, provided an overview of the Company's operations, and discussed the principal factors leading Atmos Energy to make the rate filing.
- Joe T. Christian: Discussed the basis for the 2014 rate filing; sponsored the revenue requirements, the Company's cost of service studies, projected operation and maintenance (O&M) as well as the taxes (other than income taxes), included in the cost of service studies; explained the inclusion of all AMI investment in base rates; supported the Company's proposed capital structure and imbedded cost of debt; and updated the proposed construction allowances to reflect the updated imbedded cost of mains and services.
- Ann E. Bulkley: Provided a recommendation regarding the need for a fair and reasonable return on equity.

- Paul H. Raab: Presented and supported the Company's class cost of service study and proposed cost allocation, rate design, and the proposed rates.

- Thomas H. Petersen: Discussed the Company's rate base calculation and the calculation of depreciation expense and cash working capital.

- Jared N. Geiger: Presented the Company's billing determinants in support of the respective base rate revenue increases over the test period.

- Jason L. Schneider: Provided support for the Company's historic books and records, sponsored the Company's cost assignment and allocation manual, and presented the methodology for cost allocation and the shared services allocations.

2. Commission Staff

24. In response to Atmos Energy's direct testimony, Staff filed answer testimony of five witnesses, which are summarized below:

- Karlton Kunzie: Introduced Staff's other witnesses and addressed the timing of the Company's rate filing, the Company's proposed rate base calculation, the Company's proposal for inclusion of AMI costs, the Company's proposal to include gas storage inventory costs in rate base, the Company's proposal for inclusion of construction work in progress in rate base, the Company's proposal to amortize a one-time increase in executive retirement expenses, the Company's proposal on rate case expenses, and Staff's recommended revenue requirement increase.

- Dr. Scott E. England: Discussed the Company's requested capital structure and rate of return on rate base; provided Staff's recommended rate of return on equity and the proper level of debt and cost of debt to use in the overall rate of return; and provided Staff's recommended return on rate base (or weighted average cost of capital) for Staff's test period.

- Richard Reis: Addressed the Company's cost classification and allocation methodology and discussed the Company's proposal to increase the facility charge for residential customers from the existing $10.75 per bill to $15.75.

- Sandi M. Kahl: Categorized and summarized more than 50 public comments received regarding this proceeding.

- William W. Harris: Addressed weather normalized billing determinants, the Company's proposal on the use of a declining usage factor, and the associated revenues for Staff's revenue requirement.

3. OCC

25. In response to Atmos Energy's direct testimony, the OCC filed answer testimony of two witnesses, which are summarized below:

- Cory Skluzak: Introduced the OCC's other witness; addressed the Company's history of rate increases, their impact on ratepayers, the recently concluded 2013 rate case proceeding, the Company's adjusted historic test year (HTY) rate base and income statement items; recommended numerous adjustments to the Company's rate base and income statement as well as several conditional recommendations; sponsored the OCC's revenue requirement model; and addressed the Company's Phase II proposals regarding cost allocation and rate design change to increase the fixed customer charge.

- Ronald Fernandez: Addressed adjustments to the OCC's revenue requirement model for the HTY ending December 31, 2013 on rate of return issues, including the OCC's recommended capital structure and return on equity proposals.

4. EOC

26. In response to Atmos Energy's direct testimony, EOC filed answer testimony of two witnesses, which is summarized below:

- William B. Marcus: Identified and addressed certain incentive compensation and other head office cost issues related to the Company's proposed revenue requirement; sponsored a cost of service study that reduced both the allocation of costs to the residential class and the residential customer cost; and addressed the Company's proposal to increase the residential customer charge.

- Sanders Arnold: Provided information regarding the demographics and usage characteristics of the low-income utility customer population and the impact on such customers of the Company's proposed residential customer charge.

5. Atmos Energy's Rebuttal

27. In addition to the direct and answer testimony filed in this proceeding, Atmos Energy filed the rebuttal testimony of seven witnesses, which is summarized below:

- Joe T. Christian: Introduced the Company's other rebuttal witnesses; responded to issues raised by the OCC and Staff related to the Company's proposed capital structure and adjustments to certain income statement expenses; responded to issues raised by the OCC and EOC regarding incentive compensation; and commented on Staff's testimony related to the public comments filed in this proceeding.

- Ann E. Bulkley: Responded to Staff and the OCC as it relates to the just and reasonable return on equity and the appropriate capital structure for Atmos Energy in Colorado.

- Paul H. Raab: Responded to Staff, OCC, and EOC's assertions related to the Company's class cost of service study, implied class revenue responsibility, proposed rate design and the relationship between income and usage; presented and supported the Company's final class cost of service study and resulting rate designs, based on a revised revenue requirement that reflects a Staff O&M adjustment and to reflect the adjustment to rate case expense disclosed in discovery.

- Thomas H. Petersen: Responded to the OCC and Staff regarding the Company's rate base calculation, the calculation of depreciation expense, and the cash working capital.

- Jared N. Geiger: Responded to Staff and the OCC regarding the proration adjustment to bills, weather normalization, and the declining usage adjustment.

- John M. Robbins: Responded to the OCC and EOC regarding Atmos Energy's incentive compensation plans.

- John R. Ellerman: Further responded to the OCC and EOC regarding Atmos Energy's incentive compensation plans.

28. At the hearing on August 14, 2014, Mr. Christian, Mr. Kunzie, Mr. Arnold, and Mr. Skluzak testified in support of the Settlement Agreement. *Supra,* ¶¶ 49-56.

B. Summary of the Contested Issues.

29. The Parties' initial positions on the issues relevant to the Settlement Agreement are summarized below.

1. Return on Equity and Capital Structure.

30. Atmos Energy identified 10.00 to 10.75 percent as a reasonable range for its Return on Equity (ROE) and proposed an authorized ROE of 10.40 percent. The Company proposed a capital structure consisting of 55.78 percent common equity and 44.22 percent

long-term debt, based on the end of the period, February 28, 2014. Staff recommended a capital structure of 48.76 percent debt and 51.24 percent equity and an authorized ROE of 9.57 percent. The OCC recommended an ROE for Atmos Energy of 9.20 percent and a test period end capital structure of 52.01 percent equity and 47.99 percent debt.

2. End of Year v. 13-Month Average Rate Base.

31. The Company used end of year rate base (as of December 31, 2013) to prepare the baseline cost of service study. Staff and OCC both recommended that the Commission reject Atmos Energy's use of year-end rate base and use of 13-month average rate base instead.

3. Gas Storage Inventory and Working Capital.

32. Atmos Energy proposed to include net plant in service, storage gas, accumulated deferred income tax, customer advances, customer deposits, prepaid pension, other prepayments, and cash working capital requirements in rate base. Staff and the OCC recommended that gas storage inventory should be removed from rate base and a carrying charge based upon short-term interest rates should be collected in the Gas Cost Adjustment (GCA). The OCC also recommended adjustments due to the inclusion of prepayments in working capital and cash requirements in cash working capital.

4. Residential Facilities Charge.

33. Atmos Energy proposed to increase the residential facilities charge (also known as fixed facilities charge or services and facilities charge) from $10.75 per month to $15.75 per month, an increase of approximately 47 percent. Staff, EOC, and the OCC recommended that the Commission deny the Company's proposal to increase the facilities charge for residential customers. Staff recommended a General Rate Schedule Adjustment (GRSA) of 2.36 percent be

applied to all base rates for all services and to both the facilities charge and the usage charge to account for the class cost of service results.

5. Operation and Maintenance (O&M) and Administrative and General Expenses.

34. Staff recommended, in its Answer Testimony, a correction reducing rate case expense by $251,733, and that the Company use actual rate case expenses rather than projected or estimated rate case expenses. The OCC recommended, based on the Company's admission in a discovery response, a correction reducing rate case expense by $251,733. Further, the OCC recommended that the Company's proposed rate case expense for this proceeding of $553,466 be reduced to $310,455, and that the reduced rate case expense amount be amortized over three years.

35. The OCC recommended reversing and removing $333,333 from O&M as a result of the data integration (GIS) project. As a conditional recommendation, the OCC recommended that, if the Commission accepts the inclusion of $333,333 for the GIS project, that $130,378 of savings associated with this project should be applied as an offset.

36. Staff recommended a denial of one-time retirement cost adjustment of $88,124. The OCC recommended a denial of one-time retirement cost adjustment of $88,124 and recommended a denial of certain of the Company's incentive compensation programs and associated expense. EOC recommended executive compensation disallowance as follows: (1) short term incentives – disallow $715,016 in expenses and $361,352 in capitalized incentives; (2) long term incentives – disallow $484,931 expense that is allocated to Colorado; (3) supplemental executive retirement program – disallow $197,544 in test year expenses;

(4) disallow pensions for board of directors of $49,539 allocated to Colorado; and (5) disallow $23,727 of directors' and officers' liability insurance.

6. Test Year Revenues.

37. Staff recommended denying a Company adjustment that decreased revenues by $373,793 related to a declining usage projection. The OCC supports a revenue reduction of $341,684 based on its weather normalization methodology.

C. The Settlement Agreement.

38. The Settlement Agreement (Appendix A) is incorporated by reference in this Decision as if fully set forth herein and is summarized below.[2]

39. The Parties stipulate the Settlement Agreement proposes a resolution to all of the issues raised in this proceeding. Atmos Energy will be authorized a rate increase in annual base revenues of $2,400,000 (Settlement Rate Increase). The Company states this is an overall increase to customer bills of 2.11 percent. Attachment 1 to the Settlement Agreement (Appendix A) provides the calculations supporting the Settlement Rate Increase.

40. The revenue requirement is based on a historic test period of the 12 months ending December 31, 2013 (Settlement Test Period). The Settlement Rate Increase is calculated based on a rate base of $111,296,658 using the 13-month average methodology for the 2013 Historical Test Period.

41. A rate of return (ROR) on equity of 9.72 percent was utilized, which is the same percentage authorized in Proceeding No. 13AL-0496G. The capital structure consists of the

[2] The description of the Settlement Agreement is not intended to be a full and complete description of the entire Settlement Agreement. The Settlement Agreement speaks for itself and is incorporated by reference in this Decision as Appendix A.

actual test period year-end percentages of 48 percent debt and 52 percent equity. This results in a weighted average cost of capital of 8.04 percent. The Parties agreed that Atmos Energy's authorized ROR on equity for the purposes of any earnings evaluation and calculations in Atmos Energy's annual filing pursuant to Rule 4006(a) of the Rules Regulating Gas Utilities and Pipeline Operators, 4 *Code of Colorado Regulations* (CCR) 723-4, (also known as an Appendix A filing), until the effective date of rates in the next rate case shall be any ROR on equity determined to be within the range of 9.5 percent to 10 percent.

42. The Settlement Agreement addresses the revenue impact of all of Atmos Energy's per book investments associated with its statewide deployment of Advanced Metering Infrastructure (AMI). For purposes of this proceeding only, the Parties have agreed to a negative adjustment to the revenue requirement in this case to reflect imputed cost savings associated with Atmos Energy's AMI program in the amount of $624,000. This adjustment does not specifically accept or reject any particular adjustment or regulatory principle proposed by any of the Parties to this proceeding. The Parties intend that the imputed annual savings stated above shall accrue to customers by being reflected in rates at least through December 31, 2015.

43. The Settlement Agreement reflects rate case expenses of $350,000 for this proceeding and amortizes those expenses over two years. Atmos Energy agreed that it will not seek to reflect in its revenue requirement in any future rate case any unamortized balance of rate case expenses associated with this proceeding or Atmos Energy's last general rate case (Proceeding No. 13AL-0496G).

44. The Settlement Rate Increase includes a decrease in test year revenue of $341,684 associated with the adoption of the Weather Normalization Adjustment that uses the weather

normalization methodology from Atmos Energy's prior rate case (Proceeding No. 13AL-0496G) as described in Answer Testimony of OCC Witness Cory Skluzak.

45. As stated in the Settlement Agreement, the Settlement Rate Increase is allocated to the customer classes by increasing the non-gas revenues collected from each customer class (residential, small commercial and commercial, irrigation service, and transportation service) by a uniform 7.11 percent. Atmos Energy states the overall impact of the $2.4 million increase in annual base revenues will be an increase to customers' bills of 2.11 percent. Each class's rates were designed and included in the tariffs as Attachment 3 to the Settlement Agreement (Appendix A).

46. The Settlement Rate Increase shall go into effect as soon as practical but no later than November 1, 2014. Support for the calculation of the agreed-upon base rate increase and the derivation of the specific distribution system rates is provided in Attachment 2 to the Settlement Agreement (Appendix A). Upon approval of the Settlement Agreement, Atmos Energy will make a compliance Advice Letter filing on no less than two-day notice to implement tariff sheets included in Attachment 3 to the Settlement Agreement (Appendix A).

47. The Parties also reached agreements relating to Atmos Energy's future rate case filings. In particular, Atmos Energy agreed that any general rate case filed on or before December 31, 2015: (a) will be limited to revenue requirement issues (*i.e.,* will not include any class cost of service issues, also known as rate design issues and "Phase II" issues); and (b) will include a proposal by Atmos Energy that any Commission-approved revenue increase be implemented through a GRSA that applies a uniform percentage increase to all non-gas facilities charges and distribution system rates.

48. In addition, in any future rate case setting rates effective on or after January 1, 2016, the Staff, the OCC, and EOC each agree that they: (a) will not propose any adjustment to Atmos Energy's per book investments included as of December 31, 2013 associated with Atmos Energy's statewide deployment of AMI; and (b) will not propose any negative adjustment to Atmos Energy's revenue requirement to reflect imputed cost savings associated with the costs incurred and as reflected in Atmos Energy's per book investments associated with Atmos Energy's AMI program as of December 31, 2013. Finally, the Parties agreed that Atmos Energy shall use the regulatory principles reflected in their Settlement Agreement for purposes of Atmos Energy's Annual Reports, GCA calculations, and its annual filing pursuant to Rule 4006(a), 4 CCR 723-4, (also known as an "Appendix A" filing).

D. Hearing Testimony in Support of Settlement Agreement.

1. Atmos Energy.

49. Mr. Christian testified on behalf of Atmos Energy in support of the Settlement Agreement. Mr. Christian testified that the Settlement Agreement (as a whole) reflects consideration of all the Parties' positions on the issues in this proceeding, and strikes a fair balance between the Parties. He testified that the Settlement Agreement fairly represents the interests of EOC, OCC and Staff's constituencies, while also striking a balance with Atmos Energy's interests. Mr. Christian testified that because the comprehensive Settlement Agreement considers and balances all Parties' interests, it results in just and reasonable rates that are in the public interest.

50. Mr. Christian explained how the Parties calculated the agreed-upon $2.4 million increase to the Company's annual revenues. Starting with the revenue requirement presented in the Company's rebuttal testimony, the Parties made various adjustments addressing the contested

issues, with the goal of reaching the $2.4 million figure. *See* Attachment 1 to Appendix A. The Parties did not apply a strict formula to reach the $2.4 million figure.

51. Mr. Christian explained Hearing Exhibit 22. Hearing Exhibit 22 (Table 1) depicts the average monthly bill for each ratepayer class, and provides an uncomplicated picture of the impact the proposed increase will have on a monthly basis for each ratepayer class, based on their average monthly bill. It illustrates how the overall 2.11 percent increase is allocated to customers in Atmos Energy's four rate areas. For example, based on the average monthly bill, residential ratepayers will see an increase of 2.43 percent, or approximately $1.47 (per month); commercial ratepayers will see an increase of 1.55 percent or approximately $4.15 (per month); irrigation ratepayers will see an increase of 1.16 percent or approximately $12.28 (per month); and transportation ratepayers will see an increase of 6.87 percent or approximately $35.98 (per month). Hearing Exhibit 22, Table 1. Similarly, Table 2 of Hearing Exhibit 22 illustrates the impact of the proposed increase based upon the average bill for each ratepayer class during a peak usage month (January 2013). The overall percentage increase anticipated by the Settlement Agreement is less than half of the increase Atmos Energy originally requested.

2. EOC.

52. Mr. Arnold testified on behalf of EOC in support of the Settlement Agreement. He believes the Settlement Agreement represents a fair compromise of the issues presented in this proceeding. From the perspective of EOC, the Settlement Agreement is just, reasonable, nondiscriminatory, and in the public interest because it protects its constituency -- low income households -- from a disparate impact of the rate increase. Mr. Arnold believes the cap on the increase to the residential facilities charge (also known as the fixed facilities charge or the services and facilities charge), and the $0.25 increase to residential rate payers (as opposed to the

$5 increase originally sought by Atmos Energy) is especially beneficial to low income households based upon historical data. In addition, EOC also believes the Settlement Agreement's provision spreading the rate increase evenly across ratepayer classes further supports a finding that the Agreement is just, reasonable, nondiscriminatory, and in the public interest. Finally, from the EOC's perspective, the moratorium on the Company filing a rate case raising "Phase II" issues (until December 31, 2015) benefits the public interest.

3. Staff

53. Mr. Kunzie testified on behalf of Staff in support of the Settlement Agreement. He agreed with Mr. Christian's testimony. In addition, Staff supports the Settlement Agreement because Atmos Energy did experience increased costs to provide its service which had not been recovered. Those increased costs, in Mr. Kunzie's view, justify the rate increase proposed by the Settlement Agreement. Mr. Kunzie explained that it is in the public interest to ensure that a utility is able to recover the costs for the service it provides, which includes expenses and an opportunity to earn a reasonable return on its investment. Indeed, recovery of costs and opportunity to earn a reasonable return on its investment enables utilities to continue to provide reliable and safe service. Mr. Kunzie believes the Settlement Agreement accomplishes these goals. And, according to Mr. Kunzie, the Settlement Agreement evenly increases rates across all classes of ratepayers, rather than focusing its increase on residential ratepayers (as originally proposed by Atmos Energy). This demonstrates that the rates resulting from the revenue requirement increase are nondiscriminatory. This is an additional reason Mr. Kunzie believes the Settlement Agreement results in just, reasonable, and nondiscriminatory rates that are in the public interest. Mr. Kunzie also pointed out that the agreed-upon revenue increase ($2.4 million) is close to the figure Staff proposed in response to Atmos Energy's original position.

4. OCC

54. Mr. Skluzak testified in support of the Settlement Agreement on behalf of the OCC. He testified that the Settlement Agreement is the result of negotiations between the parties wherein they all represented their best interests or their constituencies' best interests. He believes the Settlement Agreement represents a fair and complete resolution of the issues presented through the testimony filed by the Parties in this proceeding. The overall increase in rates is less than half of that requested originally by Atmos Energy. Mr. Skluzak highlighted this as a reason the OCC supports the Settlement Agreement. And, the Settlement Agreement results in lower litigation costs to all Parties and eliminates the uncertainty created by litigating all disputed issues. Mr. Skluzak also believes the Settlement Agreement is in the public interest because it spreads the rate increase evenly across all classes of ratepayers, as opposed to allocating the majority of the increase on residential ratepayers, as Atmos Energy originally proposed.

55. In addition, Mr. Skluzak believes the OCC's constituency receives another benefit from the Settlement Agreement's moratorium (until December 31, 2015) against Atmos Energy filing a rate case that raises "Phase II" issues. That moratorium allows the OCC in a future rate proceeding to focus its limited resources on the Company's request for a revenue increase, rather than divert resources to "Phase II" issues. For that reason, Mr. Skluzak believes the moratorium is in both in the public interest and the best interests of the OCC's constituency. Moreover, Mr. Skluzak also agreed with Mr. Kunzie's testimony that the Settlement Agreement is in the public interest because it allows Atmos Energy to recover its investment related costs, operating expenses, and to have an opportunity to earn a reasonable return on those investments.

56. Mr. Skluzak testified that the resulting rates from the increased revenue requirement reflect the Company's cost of service, and are just, reasonable, nondiscriminatory, and in the public interest. An important factor in the OCC signing onto the Settlement Agreement—and one which supports a conclusion that the rates are just, reasonable, nondiscriminatory, and in the public interest—is that it proposes a uniform increase among all rate classes for base non-gas revenues. In addition, the Settlement Agreement caps the increase to the fixed facilities customer charge at $11 for residential ratepayers, and allows for a small increase of $0.25 to residential ratepayers, as opposed to the Company's original request for a $5 increase. Mr. Skluzak believes these terms of the Settlement Agreement further support a conclusion that the resulting rates are just, reasonable, nondiscriminatory, and in the public interest.

E. Applicable Regulatory Principles and Governing Law.

57. The Commission must ensure that all rates charged by public utilities, including Atmos Energy, are just, nondiscriminatory, and reasonable. §§ 40-3-101 and 102, C.R.S. The Commission's determination as to what is a fair, just, and reasonable rate is a matter of discretion. *Consumer Counsel v. Public Utils. Comm'n,* 786 P.2d 1086, 1097 (Colo. 1990), citing *Mountain States Telephone & Telegraph Co. v. Public Utils. Comm'n,* 182 Colo. 269, 279-80, 513 P.2d 721, 726 (1973). In exercising this discretion, the Commission's findings and conclusions must be based on substantial evidence. *See Pub. Serv. Co. of Colo. v. Trigen-Nations Energy Co.,* 982 P.2d 316, 322 (Colo. 1999) (*en banc*).

58. The Commission must exercise reasoned judgment in setting rates. Ratemaking is a legislative function and not an exact science. *Public Utils. Comm'n v. Northwest Water Corporation*, 168 Colo. 154, 173, 551 P.2d 266, 276 (1963); *City and County of Denver v. Public*

Utils. Comm'n, 129 Colo. 41, 43, 266 P.2d 1105, 1106 (1954). As a consequence, the Commission "may set rates based on the evidence as a whole" and "need not base its decision on specific empirical support in the form of a study or data." *Colorado Office of Consumer Counsel v. Public Utils. Comm'n*, 275 P.3d 656, 660 (Colo. 2012).

59. Under the just and reasonable standard, the Commission has the primary responsibility for balancing "the investor's interest in avoiding confiscation and the consumer's interest in prevention of exorbitant rates" (*Colorado Municipal League v. Public Utils. Comm'n*, 687 P.2d 416, 418 (Colo. 1984)), and for setting rates that "protect both (1) the right of the public utility company and its investors to earn a return reasonably sufficient to maintain the utility's financial integrity; and (2) the right of consumers to pay a rate which accurately reflects the cost of service rendered." *Public Service Company of Colorado v. Public Utils. Comm'n*, 644 P.2d 933, 939 (Colo. 1982). The utility's right to earn a reasonable return incorporates the principle that the Commission-authorized rate of return ("ROR") is a return that the utility has a reasonable opportunity to realize, and is not an ROR that the utility is guaranteed to realize.

60. The Commission has supported the approval of ranges for the authorized ROE. Decision No. C13-1568, in Proceeding No. 12AL-1268G, issued December 11, 2013; Decision No. C11-1373, in Consolidated Proceeding No. 11AL-382E and 11AL-387E, issued December 6, 2011. Allowing a range for the authorized ROE allows the utility to maintain its financial integrity and to attract capital in today's market.

61. In the context of ratemaking, the Colorado Supreme Court recently reiterated "that 'it is the result reached, not the method employed, which determines whether a rate is just and reasonable.'" *Glustrom v. Public Utils. Comm'n*, 280 P.3d 662, 669 (Colo. 2012), quoting *Colorado Ute Electric Association, Inc. v. Public Utils. Comm'n*, 198 Colo. 534, 539, 602 P.2d

861, 864 (1979)(citing *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944)).

62. Moreover, it is recognized that "[t]he public and judicial policies in Colorado" favor settlement. *Colorado Ins. Guar. Ass'n v. Harris,* 872 P.2d 1139, 1142 (Colo. 1992) (*en banc*), citing *Davis v. Flatiron Materials Co.*, 511 P.2d 28, 32 (Colo. 1973).

F. Conclusions.

63. The Parties' witnesses provided substantial credible evidence that the Settlement Agreement results in rates that are just, reasonable, nondiscriminatory, and in the public interest. *Supra,* ¶¶ 49-56. The following are several examples of that evidence: the $2.4 million decrease in the Company's original rate increase request of $4.8 million; the cap on fixed facilities charges to residential customers; the $0.25 increase on fixed facilities charges to residential customers (as opposed to the $5 across the board increase originally proposed); the uniform increase of non-gas revenue across all classes of ratepayers; the moratorium on filing a rate case raising "Phase II" issues until after December 31, 2015; and the increased revenue requirement in an amount which allows Atmos Energy to recover its costs to provide safe, reliable and efficient service, while also having an opportunity to earn a reasonable return on its investment. The Settlement Agreement embodies compromises, which resolve the Parties' disputes in a manner that is in the public interest. The ALJ finds that the Settlement Agreement (Appendix A) represents a just, equitable, and reasonable resolution of issues that were contested among the Parties in this proceeding.

64. All of the Parties support approval of the Settlement Agreement without modification. Based on the record in this proceeding, including the testimony, attachments, the Settlement Agreement, (Appendix A), and as oral testimony presented at the evidentiary hearing,

the ALJ finds that the terms, conditions, and rates contained in the Settlement Agreement comport with Commission standards.

65. For the foregoing reasons and authorities, the ALJ finds that the terms, conditions, and rates contained in the Settlement Agreement and are just, reasonable, nondiscriminatory, and in the public interest. Approval of the Settlement Agreement is in the public interest and will result in just, reasonable, and nondiscriminatory rates consistent with §§ 40-3-101 and 102, C.R.S. Therefore, the terms and conditions of the Settlement Agreement will be approved and adopted without modification.

66. In accordance with § 40-6-109(2), C.R.S., it is recommended that the Commission enter the following order.

IV. ORDER

A. The Commission Orders That:

1. The Settlement Agreement and Attachments 1 through 3 thereto (attached to this Decision as Appendix A), executed by Atmos Energy Corporation (Atmos Energy), Trial Staff for the Public Utilities Commission of the State of Colorado, the Colorado Office of Consumer Counsel, and Energy Outreach Colorado, are incorporated by reference as if fully set forth herein.

2. The Settlement Agreement (Appendix A), is approved in its entirety and without modification.

3. The tariff sheets filed on April 2, 2014 with Advice Letter No. 511 are permanently suspended.

4. Atmos Energy shall make a compliance Advice Letter filing to implement the rates set forth in the Settlement Agreement and the attachments thereto (Appendix A) on not less

than two business days' notice. The advice letter and tariff shall be filed as a new advice letter proceeding and shall comply with all applicable rules. In calculating the proposed effective date, the date the filing is received at the Commission is not included in the notice period, and the entire notice period must expire prior to the effective date. The advice letter and tariff must comply in all substantive respects with this Decision in order to be a compliance filing on shortened notice.

5. Energy Outreach Colorado's "Motion to Strike Certain Rebuttal Testimony" is denied as moot.

6. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

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

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

b) If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the Parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the ALJ and the Parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

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

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

MELODY MIRBABA

Administrative Law Judge

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE STATE CORPORATION COMMISSION OF THE STATE OF KANSAS

Before Commissioners: Mark Sievers, Chairman
Thomas E. Wright

In the Matter of the Application of Atmos Energy for Adjustment of Its Natural Gas Rates in the State of Kansas.))) Docket No. 12-ATMG-564-RTS

ORDER GRANTING JOINT MOTION TO APPROVE STIPULATION AND AGREEMENT

This matter comes before the State Corporation Commission of the State of Kansas (Commission) on the Application of Atmos Energy (Atmos) seeking approval to adjust its natural gas rates. After reviewing the pleadings, files, and records, the Commission makes the following findings and conclusions:

I. BACKGROUND

1. Atmos is a natural gas public utility operating in Kansas. Atmos provides retail natural gas service to approximately 128,502 customers in Kansas, in 106 communities and two unincorporated irrigation customers in 32 counties.

2. On January 26, 2012, Atmos filed its Application to adjust its natural gas rates pursuant to K.S.A. 66-117, K.S.A. 66-1,200, *et seq.,* and K.A.R. 82-1-231. In its Application, Atmos requested a gross annual revenue increase of $9,705,116 and an overall rate of return of 8.78%. Atmos proposed an increase in the monthly facility charge, which it believed would more appropriately provide for recovery of fixed costs and an annual rate adjustment provision.

3. In support of its Application, Atmos submitted testimony from eight witnesses and the schedules required by K.A.R. 82-1-231.

4. On February 9, 2012, the Prehearing Officer granted intervention to the Citizens' Utility Ratepayer Board (CURB).

5. On February 15, 2012, the Commission issued a Suspension Order suspending the Application until September 22, 2012, 240 days from the date of the Application. Since September 22, 2012 falls on a Saturday, the due date for the Commission's Order is extended to September 24, 2012. K.A.R. 82-1-217(a).

6. On April 24, 2012, a public hearing was held, allowing ratepayers to hear about the proposed rate increase and share their concerns with the Commission.

7. On June 8, 2012, Commission Staff (Staff) filed direct testimony from seven witnesses, recommending Atmos receive a rate increase of $1.06 million.

8. On June 8, 2012, CURB filed testimony from three witnesses, recommending Atmos receive a revenue increase of no more than $2.95 million. On June 22, 2012, CURB filed cross-answering testimony by two witnesses, revising their recommended revenue increase to $3.02 million.

9. On June 27, 2012, Atmos filed its rebuttal testimony from six witnesses.

10. At the July 2, 2012 Settlement Conference, the parties met to discuss the issues in this docket. On July 5, 2012, Atmos and Staff (collectively the Signatories) filed the resulting Joint Motion to Approve Stipulation and Agreement. The Stipulation and Agreement is attached as Attachment 1. CURB neither joined in, nor opposed the proposed settlement.

11. On July 10, 2012, Atmos submitted the testimony of Joe T. Christian and Staff submitted the testimony of Laura Bowman in support of the Stipulation and Agreement.

12. On July 18, 2012, the Commission held a hearing on the proposed Settlement and Agreement. Atmos, Staff, and CURB participated in the hearing.

II. TERMS OF THE STIPULATION AND AGREEMENT

13. The Signatories agreed to a $2.8 million annual revenue increase for Atmos.

14. The Signatories agreed that the $2.8 million revenue requirement would include a decrease in Atmos's depreciation expense consistent with the rates proposed by Staff witness William W. Dunkel. Atmos is only agreeing to the depreciation rates proposed by Dunkel, not his policy recommendations. Dunkel's policy recommendations (ALG v. ELG, third-party reimbursements, and FERC Order No. 631 dealing with the present value treatment of legal asset retirement obligations) may be addressed in Docket No. 08-GIMX-1142-GIV, a generic depreciation docket pending before the Commission.

15. The Signatories agreed that Atmos may continue to book the depreciation rates approved by the Colorado Public Service Commission for its Colorado/Kansas Division.

16. The agreed upon revenue requirement includes Staff's proposed incentive compensation adjustments, described in William E. Baldry's prefiled direct testimony, and is consistent with the Commission's Order in the 10-KCPE-415-RTS docket.[1] The Signatories also agreed that nothing in the Stipulation and Agreement constitutes Atmos's consent to Staff's proposed adjustments to incentive compensation. Furthermore, nothing in the Stipulation prevents the parties from challenging any future adjustments to incentive compensation.

17. The Signatories agreed that costs related to Atmos's own gas storage will continue to be recovered through base rates.

18. Atmos agreed to withdraw its requested customer rate stabilization tariff and Staff agreed to withdraw its recommendation allowing Atmos to implement a decoupling mechanism.

[1] November 22, 2010 Order: 1) Addressing Prudence; 2) Approving Application, in Part; & 3) Ruling on Pending Requests.

19. The Signatories agreed that Atmos will establish and identify post-retirement benefit expense and pension expense for Kansas direct employees and will be allowed to maintain trackers for both post-retirement benefits and pension expense for its shared service employees. The post-retirement benefits and pension expense for its Colorado/Kansas Division are included in the base rates expense for other Kansas direct divisions and thus do not require a separate base rate or tracker.

20. Atmos agreed to implement the changes proposed by Staff witness Dorothy J. Myrick to its miscellaneous tariffs.

21. The Signatories agreed to $5,843,777 in expense, including $89,711 of capitalized expense, as the Kansas jurisdictional ad valorem tax costs included in base rates. The $5,843,777 will be prorated over the remaining months of 2012 for purposes of calculating the property tax surcharge. The rates approved in Docket No. 10-ATMG-495-RTS will be used for months prior to the effective date of the new rates.

22. The Stipulation and Agreement established a three-year amortization period for actual rate case expense and pension and post-retirement benefits trackers ($61,046 in Kansas direct and $33,163 in shared services).

23. The Signatories agreed that base rates for Atmos's pension tracker going forward should include pension expense ($385,271 in Kansas direct and $181,879 in shared services) and post-retirement benefits expense ($338,194 in Kansas direct and $144,849 in shared services).

24. The Signatories agreed that to the extent possible, the rate increase should be equitably distributed among the various customer classes.

25. Atmos shall file compliance tariffs in this docket.

III. FINDINGS AND CONCLUSIONS

26. At the outset, the Commission notes that Atmos did not consider energy efficiency when proposing its rates.[2] There were also no discussions between Atmos and Staff addressing how to measure or verify any energy efficiency savings associated with the proposed rate design.[3] Staff witness Myrick testified that in developing Staff's rate design, she reduced the volume discounts in two customers classes that currently enjoy declining block rate structures – those classes being large industrial customers (two customers) and interruptible transport (39 customers).[4] Atmos testified that its industrial customers can take advantage of special tariff rate discounts[5], so reducing the price discount in the standard declining block rates for these customer classes appears to have no substantive impact on energy efficiency. The Commission finds CURB's argument that energy efficiency for all customers would be better promoted through rate design with a higher proportion of costs recovered through volumetric charges for all customers compelling. But based on the record before it, the Commission was unable to ascertain how CURB's proposal would affect Atmos's customers. The Commission concludes that the rate design approved in this proceeding is not intended to promote energy efficiency. In the future, when rate design is proposed as being energy efficient, the resulting savings must be measurable.

[2] Transcript of July 18, 2012 Hearing (Transcript) at 50.

[3] Transcript at 53.

[4] Transcript at 101-102.

[5] Transcript at 47-48.

27. A unanimous settlement agreement is one entered into by all parties or not opposed by any party.[6] Here, Atmos and Staff are signatories to the settlement and CURB does not oppose the settlement. Therefore, the proposed Stipulation and Agreement is a unanimous settlement agreement. Even in the case of non-unanimous settlement agreements, the Commission may approve the agreement provided the Commission makes an independent finding, which is supported by substantial evidence on the record as a whole, and results in just and reasonable rates.[7]

28. Generally, Kansas law encourages settlement.[8] Settlements are beneficial when the parties agree upon a rate which is in the public interest, and without the expense of litigation.[9]

29. The Commission is charged with determining whether rates for natural gas public utilities are just and reasonable.[10] In making that determination, the Commission's goal should be to set a rate fixed within the "zone of reasonableness" after applying a balancing test which weighs the interests of all concerned parties.[11] The interests of (1) the utility's investors vs. ratepayers; (2) present vs. future ratepayers; and (3) the public interest must be weighed when determining whether a rate is in the "zone of reasonableness".[12]

---

[6] K.A.R. 82-1-230a(2).

[7] *Farmland Industries, Inc. v. Kansas Corp. Comm'n*, 24 Kan. App.2d 172, 186, 943 P.2d 470, 484, *rev. denied*, 263 Kan. 885 (1997).

[8] *Bright v. LSI Corp.*, 254 Kan. 853, 858, 869 P.2d 686, 690 (1994).

[9] *Farmland Industries*, 24 Kan. App.2d at 195, 943 P.2d at 489.

[10] K.S.A. 66-1,202.

[11] *Kansas Gas & Elec. Co. v. State Corp. Comm'n*, 239 Kan. 483, 491, 720 P.2d 1063, 1072 (1986).

[12] *Id.*

30. The Commission must find that the settlement is supported by substantial, competent evidence based on the record as a whole. In an earlier rate case involving Atmos, Docket No. 08-ATMG-280-RTS, the Commission established a five factor test to evaluate proposed settlement agreements. The five factors are: (1) Did opposing parties have an opportunity to be heard and offer their grounds for opposition; (2) Is the stipulation supported by substantial, competent evidence; (3) Does the stipulation and agreement conform with applicable law; (4) Does the stipulation and agreement result in just and reasonable rates; and (5) Is the stipulation and agreement in the public interest.[13]

31. As to the first factor, CURB did not oppose the Stipulation and Agreement.[14] Therefore, there were no parties who opposed the Stipulation and Agreement. Furthermore, CURB was given an opportunity to participate in the Settlement Hearing, and chose to do so by presenting its own witness and cross-examining witnesses testifying on behalf of both Atmos and Staff. Not only did CURB not oppose the Stipulation and Agreement, but its counsel admitted, "we do think that in general the terms are very good for consumers. The Settlement embodies a lot of the terms that CURB asked for in the Settlement. In fact, we were very, very close to a settlement."[15] CURB's counsel also added, "I would agree with both parties that they have got a Settlement here that is pretty good for customers. If the Company thinks it's good for them, then I think we have got a deal that everybody can walk away and feel good about."[16]

---

[13] *In the Matter of the Application of Atmos Energy for Adjustment of Its Natural Gas Rates in the State of Kansas*, Docket No. 08-ATMG-280-RTS, Order Approving Contested Settlement Agreement, filed May 12, 2008,¶ 11.

[14] Transcript at 28.

[15] Transcript at 28.

[16] Transcript at 29.

32. The Stipulation and Agreement is supported by substantial, competent evidence. The parties prefiled direct testimony from eighteen witnesses, including eight on behalf of Atmos, three of behalf of CURB, and seven on behalf of Staff. The parties also prefiled schedules, cross-answering testimony, and rebuttal testimony. All of the prefiled testimony was entered into the record and reviewed by the Commission.

33. The Commission also received prefiled testimony and heard live testimony in support of the proposed Stipulation and Agreement. The Commission finds the testimony filed by Christian and Bowman to be credible and to be supportive of adoption of the Stipulation and Agreement.

34. While the Commission believes the proposed Stipulation and Agreement, when viewed in its entirety,[17] is supported by substantial, competent evidence, it is concerned that there is not more detail supporting the parties' decisions to allocate costs among classes in rate design. Having the parties offer some justification for their cost allocation and rate design would allow the Commission to more effectively evaluate the fairness and reasonableness of a proposed rate design. In future dockets, the Commission would hope that the parties articulate the rationale behind their adjustments and rate design as well as an assessment of the impact of the rate changes on customers.

35. The Stipulation and Agreement conforms to applicable law. Counsel for the Signatories reminded the Commission that settlements are generally encouraged under Kansas law.[18] Staff testified that it "negotiated this settlement consistent with its understanding of

[17] In applying the substantial, competent evidence standard, the Commission does not address the individual terms of the proposed Stipulation and Agreement, instead the Commission reviewed the Stipulation and Agreement, as a whole.

[18] Transcript at 21, 25.

Staff's legally authorized role in settling a rate case and Staff's understanding of applicable laws, regulations, and controlling authority. All attempts were made to ensure that this Stipulation conforms to applicable laws".[19]

36. Counsel for Atmos explained that the Stipulation and Agreement is very similar in form and substance to previous rate cases and Commission orders, including the three most recent Atmos cases.[20] Additionally, counsel for Atmos identified three recent dockets involving other natural gas utilities operating in Kansas where similar settlements were approved by the Commission. Those three dockets are: (1) Docket No. 06-MDWG-1027-RTS (Midwest Energy); (2) Docket No. 06-KGSG-1209-RTS (Kansas Gas Service); and (3) Docket No. 07-AQLG-431-RTS (Black Hills Energy).[21] Furthermore, there is nothing in the evidentiary record that suggests the terms of the Stipulation and Agreement violate any applicable laws or regulations.

37. The Stipulation and Agreement will result in just and reasonable rates. Bowman testified that

> the agreed-upon revenue requirement increase strikes the proper balance between the Company's desire to have a reasonable assurance that it will earn sufficient revenues and cash flows to meet its financial obligations and the need to keep rates as low as possible for the customers, while providing reliable natural gas service.[22]

[19] Bowman Testimony in Support of Stipulation and Agreement (Bowman) at 8-9.

[20] Transcript at 21; Atmos Exhibit 1 at 33.

[21] Atmos Exhibit 1 at 32.

[22] Bowman at 9.

The Signatories agreed to a revenue increase of $2,800,000, which is between Atmos's adjusted request for $9.1 million and Staff's recommended $1,067,000 increase. The agreed-upon revenue increase is also within CURB's recommended range of below $2.95 million.

38. Both Staff and Atmos believe that the agreed-upon rates fall within the "zone of reasonableness" as defined by Kansas courts.[23] Under the zone of reasonableness standard, the Commission must weigh the interests of the utility's shareholders vs. the ratepayers; present vs. future ratepayers; and the public interest.[24] The proposed Stipulation and Agreement strikes an appropriate balance between the interests of the utility shareholders and the ratepayers. Staff's testimony indicates there are no intergenerational issues in this docket, so the interests of present and future ratepayers are balanced.[25]

39. The rates proposed in the Settlement and Agreement make only modest adjustments to the rates which the Commission found to be just and reasonable roughly two years ago in Docket No. 10-ATMG-495-RTS. For example, under the rates proposed in the Settlement and Agreement, residential customers will have an average increase of $1.48 or 5.92% in their monthly bills and industrial customers will have an average increase of $18.04 or 4.5% in their monthly bills.[26] Therefore, the Commission finds these adjustments will not be unduly burdensome on consumers and that the new rates are just and reasonable and within the "zone of reasonableness".

[23] Bowman at 9; Christian Testimony in Support of Stipulation and Agreement (Christian) at 9.

[24] *Kansas Gas,* 239 Kan. at 491, 720 P.2d at 1072.

[25] Bowman at 10.

[26] Atmos Exhibit 4.

40. One measure of whether a rate is just and reasonable and not unduly preferential or discriminatory is to compare the proposed rate to those in other states or from other companies providing similar services. The Commission is troubled that the average monthly bill for Kansas consumers would be higher than those for consumers in nine of the eleven other states served by Atmos[27] and there appears to be no apparent relationship between residential and commercial rates. For example, Atmos reports that its average residential monthly bill in Kansas is $50.36 and the average commercial bill is $168.22, about three times higher than the average residential bill. In Illinois, which is at roughly the same latitude as Kansas, the average residential monthly bill is reported to be $33.87 (33% lower than Kansas) and the average commercial bill is $145.12 (14% lower than Kansas).[28] Why does the relationship between Kansas residential rates versus Illinois residential rates not manifest itself in a similar way with commercial rates? The Commission recognizes that rates will naturally vary by state due to their different climates, topography, soil, and other factors.[29] Yet, that analysis was not part of how the Signatories developed cost allocations and rate design – rate design in this case was primarily an accounting rather than an economic analysis. Based on the record before it, the Commission finds the agreed-upon rates fall within the "zone of reasonableness".

41. The Stipulation and Agreement is in the public interest. First, the interests of multiple parties are represented. CURB represents the interests of the ratepayers, Atmos represents the interests of its management and shareholders, and the Staff represents the interests

[27] Atmos Exhibit 4.

[28] Atmos Exhibit 4.

[29] Transcript at 80-81.

of the public generally and attempts to balance the interests of all parties.[30] Both the prefiled testimony and the testimony offered at the July 18, 2012 Hearing demonstrate that the proposed Settlement and Agreement is in the public interest.

42. Atmos's representative, Joe Christian, testified that the public interest is served by Atmos providing gas service in a safe and reliable manner, while providing a fair opportunity for Atmos to earn its return on investment.[31] Atmos's position is "the 'total effect' of the terms of the Stipulation will result in just and reasonable rates and represents an equitable balancing of the interest of all the Parties. Thus, the Stipulation is in the public interest and should be adopted by the Commission in its entirety."[32]

43. Counsel for Staff explained that the public interest is served by protecting ratepayers from unreasonably high or discriminatory rates or unreliable service.[33] Staff agreed to the proposed Settlement and Agreement because it results in a reasonable revenue increase for Atmos and provides Atmos with sufficient revenue and cash flow to meet its obligations and provide reliable service.[34] Lastly, approval of the proposed Settlement and Agreement is in the public interest because it avoids a costly and time-consuming fully-litigated hearing.[35]

---

[30] Bowman at 11.

[31] Transcript at 80.

[32] Christian at 12.

[33] Transcript at 27.

[34] Bowman at 11.

[35] Bowman at 11.

44. Counsel for CURB testified, "both parties ... have got a Settlement here that is pretty good for customers."[36]

45. For the reasons stated above, the Commission finds the proposed Stipulation and Agreement is in the public interest and should be approved.

IT IS, THEREFORE, BY THE COMMISSION ORDERED:

A. The Commission grants the Joint Motion to Approve Stipulation and Agreement in this docket.

B. The terms of the attached Stipulation and Agreement are incorporated into this Order.

C. The parties have 15 days from the date of electronic service of this Order to petition the Commission for reconsideration. K.S.A. 66-118b; K.S.A. 2011 Supp. 77-529(a)(1).

D. This Order is designated as precedent pursuant to K.S.A. 2011 Supp. 77-415, that may be relied upon in any subsequent adjudication.

E. The Commission retains jurisdiction over the subject matter and parties for the purpose of entering such further orders as it may deem necessary.

[36] Transcript at 29.

BY THE COMMISSION IT IS SO ORDERED.

Sievers, Chmn.; Wright, Com.

Dated: AUG 2 2 2012

ORDER MAILED AUG 2 2 2012

Patrice Petersen-Klein
Executive Director

BGF

ATTACHMENT 1

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Atmos Energy for Adjustment of its Natural Gas Rates in the State of Kansas	)))	Docket No. 12-ATMG-564-RTS

STIPULATION AND AGREEMENT

As a result of discussions between the Staff of the State Corporation Commission of the State of Kansas ("Staff") and Atmos Energy ("Atmos") (referred to collectively as the "Parties"), Staff and Atmos hereby submit to the Kansas Corporation Commission ("Commission") for its consideration and approval, the following Stipulation and Agreement ("Stipulation").

I. ATMOS'S APPLICATION

1. On January 26, 2012, Atmos filed an Application with the Commission to make certain changes in its rates and charges for natural gas service, which was docketed as the above captioned proceeding. Pursuant to a Commission Order, the effective date of this Application was suspended until September 24, 2012.

2. The schedules filed with Atmos's Application indicated a gross revenue deficiency of $9.70 million based upon normalized operating results for the 12 months ending September 30, 2011, adjusted for known and measurable changes in revenues, operating and maintenance expenses, cost of capital and taxes, and other adjustments.

3. In support of its Application, Atmos submitted the testimony of eight witnesses and the schedules required by K.A.R. 82-1-231.

II. STAFF AND OTHER PARTIES' PREFILED POSITIONS

4. On June 8, 2012, Staff filed its direct testimony in the above docket, recommending a rate increase of $1.06 million for Atmos. Staff recommended additional adjustments to Atmos's

proposed depreciation rates and raised several policy questions related to the calculation of depreciation rates. Staff also made recommendations regarding return on equity and adjustments to the income statement and rate base.

5. Also on June 8, 2012, CURB filed testimony in which it recommended a revenue increase of no greater than $2.95 million. CURB also reserved its right to adopt recommendations that may be made by Staff with regard to proposed depreciation rates.

6. On June 22, 2012, CURB filed cross-answering testimony on various cost allocation and rate design matters. Additionally, CURB pointed out a calculation error that occurred in the calculation of rate case expense. This error, when corrected, resulted in a revised revenue requirement of $3.02 million.

7. Atmos filed rebuttal testimony on June 27, 2012.

8. Subsequently, on July 2, 2012, Staff, Atmos and CURB met collectively to discuss the possible settlement of the issues in this matter.

III. TERMS OF THE STIPULATION

Staff and Atmos have agreed upon the following terms that settle all issues raised in this case. CURB has indicated to Staff and Atmos it is not opposed to the Stipulation but does not intend to become a signatory.

A. STIPULATED REVENUE REQUIREMENT

9. Staff and Atmos agree that Atmos's overall annual revenue increase will be two million eight hundred thousand dollars ($2.8 million).

B. MISCELLANEOUS ISSUES

10. Staff and Atmos agree the revenue requirement specified in paragraph 9 above includes a decrease in Atmos's depreciation expense consistent with the depreciation rates proposed by Staff witness William Dunkel and set forth in Appendix A to this Stipulation. Atmos agrees it will adopt

the depreciation rates in Appendix A. By agreeing to such a decrease in Atmos's depreciation rates, Atmos is not agreeing to the policy recommendations made by Mr. Dunkel. Staff and Atmos agree the policy recommendations made by Mr. Dunkel regarding ALG v. ELG, third-party reimbursements, and FERC Order No. 631 (Present Value Treatment of the "Legal" Asset Retirement Obligations) may be addressed in the generic depreciation docket, Docket No. 08-GIMX-1142-GIV, currently pending before the Commission. Atmos shall be allowed to continue to book the rates it is currently booking relating to Division 30 as approved by the Colorado Public Service Commission and outlined in Atmos Witness Christian's rebuttal testimony, pages 13-14.

11. Pursuant to the Commission's Order in Docket No. 10-KCPE-415-RTS, Staff addressed the issue of incentive compensation in its prefiled testimony. The revenue requirement specified in paragraph 9 reflects the level of incentive compensation consistent with Staff's testimony in this case. However, Staff and Atmos agree that nothing in this Stipulation constitutes an agreement by Atmos that Staff's proposed adjustments to compensation are appropriate and the Stipulation does not prevent Atmos or other parties from challenging such adjustments in the future.

12. Staff and Atmos agree the costs relating to Atmos's own gas storage will continue to be recovered in base rates as proposed by Staff and CURB.

13. Atmos agrees to withdraw its request for a Customer Rate Stabilization tariff. Staff agrees to withdraw its recommendation that Atmos be allowed to implement a decoupling mechanism.

14. Staff and Atmos agree that in addition to having amounts identified and established for Kansas direct employees for post-retirement benefit expense and pension expense in the pension trackers, Atmos shall also be allowed to maintain trackers for both post-retirement benefits and pension expense for Atmos's shared service employees. Additionally, the Parties recognize that the post retirement benefits and pension expense for Division 30 employees are included in the base rates expense amounts shown for Division 79, 80, 81 and 86 and therefore a separate base rate and tracker

amount is not necessary for Division 30 employees.

15. Atmos agrees to implement the changes in its miscellaneous tariffs proposed by Staff Witness Myrick.

C. ACCOUNTING MATTERS

16. The Kansas jurisdictional ad valorem tax costs included in base rates approved in this case is agreed to by the Parties as being $5,843,777 in expense, which includes $89,711 of capitalized expense. For purposes of calculating the property tax surcharge to be filed in December of 2012, the $5,843,777 will need to be prorated over the number of months remaining in 2012, with the rates approved in Docket No. 10-ATMG-495-RTS being used for the months prior to when rates from this case go in effect.

17. Amortization periods are established as follows:

a. actual rate case expense - three years;

b. Pension (FAS 87) and Postretirement Benefits (FAS 106) trackers in the amount of ($61,046) (Kansas direct) and $33,163 (Shared Services) - three years.

18. For the purposes of calculating Atmos's pension tracker going forward, Atmos and Staff agree the base rates agreed to in this Stipulation include the following expenses associated with Atmos's pension plan:

a. Pension Expense (FAS 87), $385,271 (Kansas direct) and $181,879 (Shared Services);

b. Post Retirement Benefits Expense (FAS 106), $338,194 (Kansas direct) and $144,849 (Shared Services).

D. CLASS COST OF SERVICE AND RATE DESIGN

19. Staff and Atmos agree that the rate increase should be equitably distributed among the customer classes, to the extent practicable, with regard to the ratios of Atmos's current rate design as

proposed in Staff's direct testimony. The resulting rates should be adjusted as shown on Appendix B hereto. The billing determinants used to calculate the rates are shown on Appendix C hereto.

20. Staff and Atmos agree that Atmos shall file a set of compliance tariffs in this docket.

IV. MISCELLANEOUS PROVISIONS

A. THE COMMISSION'S RIGHTS

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

B. PARTIES' RIGHTS

22. Atmos and Staff shall have the right to present pre-filed testimony in support of this Stipulation. Such testimony shall be filed formally in the docket and presented by witnesses at a hearing on this Stipulation. Such testimony is being filed pursuant to the Commission's schedule in this docket. Staff and Atmos request the hearing on the Stipulation be set for July 18, 2012, at 9:00 a.m.

C. WAIVER OF CROSS-EXAMINATION

23. Staff and Atmos waive cross-examination on all testimony filed prior to the filing of this Stipulation. Staff and Atmos agree that all such prefiled testimony may be incorporated into the record without objection.

D. NEGOTIATED SETTLEMENT

24. This Stipulation represents a negotiated settlement that fully resolves the issues in this docket among Staff and Atmos. Staff and Atmos represent that the terms of this Stipulation constitute a fair and reasonable resolution of the issues addressed herein. Except as specified herein, Staff and Atmos shall not be prejudiced, bound by, or in any way affected by the terms of this Stipulation (a) in

any future proceeding; (b) in any proceeding currently pending under a separate docket; and/or (c) in this proceeding should the Commission decide not to approve this Stipulation in the instant proceeding. If the Commission accepts this Stipulation in its entirety and incorporates the same into a final order without material modification, Staff and Atmos shall be bound by its terms and the Commission's order incorporating its terms as to all issues addressed herein and in accordance with the terms hereof, and will not appeal the Commission's order on these issues.

E. INTERDEPENDENT PROVISIONS

25. The provisions of this Stipulation have resulted from negotiations among Staff and Atmos and are interdependent. In the event that the Commission does not approve and adopt the terms of this Stipulation in total, it shall be voidable and neither Staff nor Atmos shall be bound, prejudiced, or in any way affected by any of the agreements or provisions hereof. Further, in such event, this Stipulation shall be considered privileged and not admissible in evidence or made a part of the record in any proceeding.

F. SUBMISSION OF DOCUMENTS TO THE COMMISSION OR STAFF

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

IN WITNESS WHEREOF, Staff and Atmos have executed and approved this Stipulation and Agreement, effective as of the _____ day of July, 2012, by subscribing their signatures below.

Holly I. Fisher, #24023
Ray Bergmeier, #24974
Litigation Counsel
Kansas Corporation Commission
1500 S. W. Arrowhead Road
Topeka, Kansas 66604
(785) 271-3196, telephone
(785) 271-3167, facsimile
Attorneys for Staff

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

Atmos Energy Corporation
Kansas Direct Property
Settled Depreciation Rates

APPENDIX A

		Mortality Characteristics						Depreciation Rates		
Account Number	Description	ASL	Iowa Curve	Gross Salvage	Cost of Removal	Net Salvage	Remaining Life	Life Rate	COR Rate	Total Rate
	STORAGE PLANT									
350.20	Rights-of-Way	50.0	R5	0.00%	0.00%	0.00%	27.96	1.71%	0.00%	1.71%
351.00	Structures and Improvements	40.0	R4	0.00%	0.00%	0.00%	21.14	1.97%	0.00%	1.97%
352.00	Wells	50.0	S4	0.00%	20.00%	-20.00%	29.23	1.72%	0.34%	2.06%
353.00	Pipelines	60.0	R3	0.00%	25.00%	-25.00%	41.52	1.24%	0.31%	1.55%
354.00	Compressor Station Equipment	60.0	S2	0.00%	0.00%	0.00%	34.35	0.92%	0.00%	0.92%
355.00	M&R Equipment	25.0	S2	0.00%	0.00%	0.00%	10.80	2.50%	0.00%	2.50%
356.00	Purification Equipment	30.0	R4	0.00%	0.00%	0.00%	9.28	1.70%	0.00%	1.70%
357.00	Other Equipment	35.0	R5	0.00%	0.00%	0.00%	13.64	2.02%	0.00%	2.02%
	TRANSMISSION PLANT									
365.20	Rights-of-Way	50.0	R5	0.00%	0.00%	0.00%	38.02	2.06%	0.00%	2.06%
366.00	Structures and Improvements	40.0	R2.5	0.00%	10.00%	-10.00%	17.24	2.65%	0.26%	2.91%
367.00	Mains - Cathodic Protection	50.0	R1.5	0.00%	11.00%	-11.00%	25.48	1.81%	0.25%	2.06%
367.01	Mains - Steel	50.0	R1.5	0.00%	7.10%	-7.10%	48.63	1.96%	0.14%	2.10%
368.00	Compressor Station Equipment	20.0	SQ	0.00%	10.00%	-10.00%	11.50	5.42%	0.54%	5.96%
369.00	M&R Station Equipment	30.0	R0.5	0.00%	20.00%	-20.00%	16.02	2.96%	0.59%	3.55%
	DISTRIBUTION PLANT									
374.02	Rights-of-Way	50.0	R5	0.00%	0.00%	0.00%	41.22	2.07%	0.00%	2.07%
375.00	Structures and Improvements	31.0	L2	0.00%	5.00%	-5.00%	20.58	3.21%	0.16%	3.37%
376.00	Mains - Cathodic Protection	50.0	R1.5	0.00%	7.90%	-7.90%	43.10	1.58%	0.16%	1.74%
376.01	Mains - Steel	50.0	R1.5	0.00%	8.00%	-8.00%	37.43	1.74%	0.16%	1.90%
376.02	Mains - Plastic	50.0	R1.5	0.00%	8.10%	-8.10%	41.73	1.85%	0.16%	2.01%
378.00	M&R Station Equipment	25.0	R0.5	0.00%	5.00%	-5.00%	18.48	3.64%	0.18%	3.82%
379.00	City Gate Equipment	30.0	R2	0.00%	5.00%	-5.00%	19.19	3.35%	0.17%	3.52%
379.08	City Gate Equipment	30.0	R2	0.00%	5.00%	-5.00%	17.91	3.35%	0.17%	3.52%
380.00	Services	38.0	S1	0.00%	36.00%	-36.00%	28.37	2.33%	0.97%	3.30%
381.00	Meters	20.0	R1	0.00%	20.00%	-20.00%	11.67	4.83%	0.97%	5.80%
382.00	Meter Installations	20.0	R1	0.00%	20.00%	-20.00%	14.73	4.71%	0.94%	5.65%
383.00	House Regulators	20.0	R1	0.00%	20.00%	-20.00%	10.16	4.88%	0.97%	5.85%
384.00	House Regulator Installations	20.0	R1	0.00%	20.00%	-20.00%	6.41	5.52%	1.10%	6.62%
385.00	Industrial M&R Equipment	23.0	R0.5	0.00%	5.00%	-5.00%	18.56	3.99%	0.20%	4.19%
387.00	Other Equipment	18.0	L3	0.00%	5.00%	-5.00%	9.49	5.95%	0.30%	6.25%
	GENERAL PLANT - DEPRECIATED									
390.00	Structures and Improvements	40.0	R2	0.00%	0.00%	0.00%	34.83	2.51%	0.00%	2.51%
390.09	Leasehold Improvements	30.0	R2	0.00%	0.00%	0.00%	17.21	3.59%	0.00%	3.59%
392.00	Transportation Equipment	8.0	L3	10.00%	0.00%	10.00%	3.29	18.93%	-1.89%	17.04%
396.00	Power Operated Equipment	8.0	R3	4.00%	0.00%	4.00%	3.79	15.33%	-0.61%	14.72%
396.04	Backhoes	8.0	R3	4.00%	0.00%	4.00%	4.14	14.64%	-0.59%	14.05%
396.05	Welders	8.0	R3	4.00%	0.00%	4.00%	5.24	13.71%	-0.55%	13.16%
	GENERAL PLANT - AMORTIZED									
391.00	Office Furniture and Equipment	15.0	SQ	0.00%	0.00%	0.00%	10.44			(1)
393.00	Stores Equipment	28.0	SQ	0.00%	0.00%	0.00%	12.55			(1)
394.00	Tools, Shop, and Garage Equipment	15.0	SQ	0.00%	0.00%	0.00%	9.06			(1)
395.00	Laboratory Equipment	15.0	SQ	0.00%	0.00%	0.00%	6.65			(1)
397.00	Communication Equipment	12.0	SQ	0.00%	0.00%	0.00%	9.25			(1)
398.00	Miscellaneous Equipment	15.0	SQ	0.00%	0.00%	0.00%	13.50			(1)
399.01	Servers Hardware	7.0	SQ	0.00%	0.00%	0.00%	5.50			(1)
399.02	Servers Software	7.0	SQ	0.00%	0.00%	0.00%	3.50			(1)
399.03	Network Hardware	7.0	SQ	0.00%	0.00%	0.00%	4.13			(1)
399.06	PC Hardware	7.0	SQ	0.00%	0.00%	0.00%	3.16			(1)
399.07	PC Software	7.0	SQ	0.00%	0.00%	0.00%	5.17			(1)
399.08	Application Software	7.0	SQ	0.00%	0.00%	0.00%	3.89			(1)

(1) General Plant Amortization Implementation

a. Each account is to be assigned the whole depreciation rate of 1/ASL.

b. Each account is to retire assets older than the average service life of the account.

c. The reserve deficit is to be amortized over the remaining life of the account.

Atmos Energy Corporation
Colorado\Kansas General Office
Settled Depreciation Rates

APPENDIX A

Account Number	Description	ASL	Iowa Curve	Gross Salvage	Cost of Removal	Net Salvage	Life Rate	COR Rate	Total Rate
		Mortality Characteristics					Depreciation Rates		
	GENERAL PLANT								
391.00	Office Furniture and Equipment	15.0	SQ	0.00%	0.00%	0.00%	8.44%	0.00%	8.44%
394.00	Tools, Shop & Garage Equipment	10.0	SQ	0.00%	0.00%	0.00%	16.57%	0.00%	16.57%
397.00	Communication Equipment	12.0	SQ	0.00%	0.00%	0.00%	8.45%	0.00%	8.45%
398.00	Miscellaneous Equipment	10.0	SQ	0.00%	0.00%	0.00%	15.46%	0.00%	15.46%
399.01	Servers Hardware	7.0	SQ	0.00%	0.00%	0.00%	21.81%	0.00%	21.81%
399.03	Network Hardware	7.0	SQ	0.00%	0.00%	0.00%	15.55%	0.00%	15.55%
399.06	PC Hardware	5.0	SQ	0.00%	0.00%	0.00%	25.25%	0.00%	25.25%
399.07	PC Software	5.0	SQ	0.00%	0.00%	0.00%	25.70%	0.00%	25.70%

Atmos Energy Corporation
Kansas - Shared Services Unit
Settled Depreciation Rates

APPENDIX A

		Mortality Characteristics					Depreciation Rates		
Account Number	Description	ASL	Iowa Curve	Gross Salvage	Cost of Removal	Net Salvage	Life Rate	COR Rate	Total Rate
	GENERAL PLANT								
390.00	Structures and Improvements	40.0	R2	0.00%	0.00%	0.00%	2.43%	0.00%	2.43%
390.09	Leasehold Improvements	20.0	R4	0.00%	0.00%	0.00%	3.82%	0.00%	3.82%
391.00	Office Furniture and Equipment	22.0	L4	0.00%	0.00%	0.00%	3.70%	0.00%	3.70%
394.00	Tools, Shop, and Garage Equipment	11.0	S6	0.00%	0.00%	0.00%	8.81%	0.00%	8.81%
397.00	Communication Equipment	15.0	R5	0.00%	0.00%	0.00%	5.36%	0.00%	5.36%
398.00	Miscellaneous Equipment	15.0	S3	0.00%	0.00%	0.00%	1.60%	0.00%	1.60%
399.00	Other Tangible Property	7.0	R5	0.00%	0.00%	0.00%	13.45%	0.00%	13.45%
399.01	Servers Hardware	10.0	SQ	0.00%	0.00%	0.00%	8.66%	0.00%	8.66%
399.02	Servers Software	10.0	SQ	0.00%	0.00%	0.00%	8.86%	0.00%	8.86%
399.03	Network Hardware	10.0	SQ	0.00%	0.00%	0.00%	8.73%	0.00%	8.73%
399.04	CPU	16.0	SQ	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
399.05	Mainframe Hardware	16.0	SQ	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
399.06	PC Hardware	7.0	S3	0.00%	0.00%	0.00%	8.77%	0.00%	8.77%
399.07	PC Software	12.0	R3	0.00%	0.00%	0.00%	6.05%	0.00%	6.05%
399.08	Application Software	12.0	R5	0.00%	0.00%	0.00%	6.54%	0.00%	6.54%
399.09	Mainframe Software	13.0	S6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
399.24	General Startup Costs	13.0	S6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Appendix B
KCC RATE DESIGN

CLASS	SETTLEMENT PROPOSED RATES		ATMOS EXISTING RATES	
	Commodity Charge	Facilities Charge	Commodity Charge	Facilities Charge
GROUP 1	(1)	(2)	(3)	(4)
Residential	$0.13700	$16.75	$0.12953	$15.50
Commercial & Public Authority	$0.13700	$37.75	$0.12953	$37.00
Schools	$0.14500	$45.00	$0.12953	$37.00
Industrial Firm	$0.13662	$81.00	$0.12953	$70.00
Transportation Firm	$0.13662	$81.00	$0.12953	$70.00
Transportation Firm School	$0.14500	$81.00	$0.12953	$70.00
GROUP 2				
Small Generator Service	$0.13662	$41.00	$0.15000	$37.50
Irrigation	$0.08880	$60.00	$0.08045	$49.00
GROUP 3				
Industrial Interruptible	$0.07610 $0.07210	$300.00	$0.07140 $0.06340	$275.00
Transportation Interruptible	$0.07610 $0.07210	$300.00	$0.07140 $0.06340	$275.00

ATMOS ENERGY CORPORATION
DOCKET NO. 12-ATMG-564-RTS
Test Year Ending 09/30/2011

APPENDIX C

DESCRIPTION		SALES SERVICE							TRANSPORTATION SERVICE		
					INDUSTRIAL/INTERRUPT						
	TOTAL COMPANY	TOTAL RESIDENTIAL 910	TOTAL COMM.-PUB AUTH 915	TOTAL SCHOOL 920	INDUSTRIAL 930	SM GENERATOR SERVICE 940	LG INDUST. INTERRUPT. 955	IRRIGATION ENGINE 965	TRANSPORTATION FIRM 930	TRANSPORT INTERRUPTIBLE 955	TRANSPORT FIRM SCHOOL 930
Total Annual Bills	1,542,006	1,414,436	117,890	985	211	823	24	3,262	3,161	472	742
Step 1	169,909,742	100,475,009	32,441,250	652,838	521,301	2,065	343,565	7,457,811	14,431,833	12,173,696	1,410,374
Step 2	265,228	0	0	0	0	0	258,734	0	0	6,494	0
Total Adj. Volumes	170,174,970	100,475,009	32,441,250	652,838	521,301	2,065	602,299	7,457,811	14,431,833	12,180,190	1,410,374
Existing Rates											
Facilities Charge		$15.50	$37.00	$37.00	$70.00	$37.50	$275.00	$49.00	$70.00	$275.00	$70.00
Volumetric Charge S1		$0.12953	$0.12953	$0.12953	$0.12953	$0.15000	$0.07140	$0.08045	$0.12953	$0.07140	$0.12953
Volumetric Charge S2							$0.06340			$0.06340	
Existing Rate Revenue	56.27%	62.75%	50.93%	30.12%	17.95%	99.01%	13.86%	21.04%	10.56%	12.99%	22.14%
Facilities Revenue	$26,937,214	$21,923,756	$4,361,930	$36,445	$14,770	$30,863	$6,600	$159,836	$221,270	$129,800	$51,940
Volumetric Revenue S1	$20,914,793	13,014,528	4,202,115	84,562	67,524	310	24,531	599,981	1,869,355	869,202	182,686
Volumetric Revenue S2	$16,815	0	0	0	0	0	16,404	0	0	412	0
Total Existing Revenue	$47,868,822	$34,938,286	$8,564,045	$121,007	$82,294	$31,172	$47,534	$759,819	$2,090,625	$999,414	$234,626
Proposed Rates											
Facilities Charge		$16.75	$37.75	$45.00	$81.00	$41.00	$300.00	$60.00	$81.00	$300.00	$81.00
Volumetric Charge S1		$0.13700	$0.13700	$0.14500	$0.13662	$0.13662	$0.07610	$0.08880	$0.13662	$0.07610	$0.14500
Volumetric Charge S2							$0.07210			$0.07210	
Proposed Rate Revenue	56.57%	63.25%	50.03%	31.89%	19.35%	99.17%	13.85%	22.81%	11.49%	13.25%	22.71%
Facilities Revenue	$28,897,973	$23,691,803	$4,450,348	$44,325	$17,091	$33,743	$7,200	$195,720	$256,041	$141,600	$60,102
Volumetric Revenue S1	$22,166,690	13,765,076	4,444,451	94,662	71,220	282	26,145	662,254	1,971,677	926,418	204,504
Volumetric Revenue S2	$19,123	0	0	0	0	0	18,655	0	0	468	0
Total Proposed Revenue	$51,083,785	$37,456,879	$8,894,799	$138,987	$88,311	$34,025	$52,000	$857,974	$2,227,718	$1,068,486	$264,606
Proposed Change In Rate Revenue											
Facilities Revenue	$1,960,759	$1,768,045	$88,418	$7,880	$2,321	$2,881	$600	$35,882	$34,771	$11,800	$8,162
Volumetric Revenue S1	$1,251,896	$750,548	$242,336	$10,099	$3,696	($28)	$1,615	$62,273	$102,322	$57,216	$21,818
Volumetric Revenue S2	$2,307	$0	$0	$0	$0	$0	$2,251	$0	$0	$56	$0
Total Rate Revenue	$3,214,963	$2,518,593	$330,754	$17,979	$6,017	$2,853	$4,466	$98,155	$137,093	$69,073	$29,980
Percent Change In Rate Revenue											
Facilities Revenue	7.28%	8.06%	2.03%	21.62%	15.71%	9.33%	9.09%	22.45%	15.71%	9.09%	15.71%
Volumetric Revenue S1	5.99%	5.77%	5.77%	11.94%	5.47%	-8.92%	6.58%	10.38%	5.47%	6.58%	11.94%
Volumetric Revenue S2	13.72%						13.72%			13.72%	
Total Rate Revenue	6.72%	7.21%	3.86%	14.86%	7.31%	9.15%	9.39%	12.92%	6.56%	6.91%	12.78%

AUG 2 2 2012

CERTIFICATE OF SERVICE

12-ATMG-564-RTS

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing Order Granting Joint Motion to Approve Stipulation and Agreement was served by electronic mail this 22nd day of August, 2012, to the following parties who have waived receipt of follow-up hard copies:

JAMES G. FLAHERTY, ATTORNEY
ANDERSON & BYRD, L.L.P.
216 SOUTH HICKORY
PO BOX 17
OTTAWA, KS 66067
Fax: 785-242-1279
jflaherty@andersonbyrd.com

JAMES PRICE, ATTORNEY
ATMOS ENERGY
PO BOX 650205
5430 LBJ FREEWAY, THREE LINCOLN CENTRE
DALLAS, TX 75265-0205
james.price@atmosenergy.com

BARTON W. ARMSTRONG, VICE PRESIDENT, OPERATIONS
ATMOS ENERGY CORPORATION
25090 W 110TH TERRACE
OLATHE, KS 66061
bart.armstrong@atmosenergy.com

DOUGLAS C. WALTHER, ASSOCIATE GENERAL COUNSEL
ATMOS ENERGY CORPORATION
P O BOX 650205
DALLAS, TX 75265-0205
douglas.walther@atmosenergy.com

KAREN P WILKES, DIVISION VICE PRESIDENT, REGULATORY AND PUBLIC AFFAIRS
ATMOS ENERGY CORPORATION
1555 BLAKE ST 400
DENVER, CO 80202
karen.wilkes@atmosenergy.com

NIKI CHRISTOPHER, ATTORNEY
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604
Fax: 785-271-3116
n.christopher@curb.kansas.gov
Hand Delivered

C. STEVEN RARRICK, ATTORNEY
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604
Fax: 785-271-3116
s.rarrick@curb.kansas.gov
Hand Delivered

DELLA SMITH
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604
Fax: 785-271-3116
d.smith@curb.kansas.gov
Hand Delivered

SHONDA SMITH
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604
Fax: 785-271-3116
sd.smith@curb.kansas.gov
Hand Delivered

DAVID SPRINGE, CONSUMER COUNSEL
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604
Fax: 785-271-3116
d.springe@curb.kansas.gov
Hand Delivered

ORDER e MAILED AUG 2 2 2012

AUG 22 2012

CERTIFICATE OF SERVICE

12-ATMG-564-RTS

RAY BERGMEIER, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604-4027
Fax: 785-271-3354
r.bergmeier@kcc.ks.gov
Hand Delivered

BRIAN G. FEDOTIN, ADVISORY COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604-4027
Fax: 785-271-3314
b.fedotin@kcc.ks.gov
Hand Delivered

HOLLY FISHER, ATTORNEY
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604-4027
Fax: 785-271-3354
h.fisher@kcc.ks.gov
Hand Delivered

ROBERT A. FOX, SENIOR LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604-4027
Fax: 785-271-3354
b.fox@kcc.ks.gov
Hand Delivered

Sheryl L. Sparks

Sheryl L. Sparks
Administrative Specialist

ORDER e MAILED AUG 22 2012

**THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

Before Commissioners: Shari Feist Albrecht, Chair
Jay Scott Emler
Pat Apple

In the Matter of the Application of Atmos Energy for Adjustment of its Natural Gas Rates in the State of Kansas.	)))	Docket No. 14-ATMG-320-RTS

ORDER APPROVING PARTIAL STIPULATED SETTLEMENT AGREEMENT; ORDER ON CONTESTED ISSUES

This matter comes before the State Corporation Commission of the State of Kansas (Commission) on the Application of Atmos Energy (Atmos) seeking approval to adjust its natural gas rates in the state of Kansas. After reviewing the pleadings, files, and records, the Commission makes the following findings and conclusions:

I. BACKGROUND

1. Atmos is a natural gas public utility operating in Kansas pursuant to certificates of convenience and necessity issued by the Commission. Atmos provides retail natural gas service to approximately 129,000 customers in Kansas, in 106 communities and two unincorporated irrigation customers in 32 counties.[1]

2. On January 9, 2014, Atmos filed an Application to increase its base rates for natural gas service pursuant to K.S.A. 66-117, K.S.A. 66-1,200, *et seq.,* and K.A.R. 82-1-231. In its Application, Atmos requested a gross annual revenue increase of $7.005 million, a return on equity (ROE) of 10.53%, and an overall rate of return of 8.44%. Atmos also requested the Commission approve a Regulatory Asset (RA) mechanism to replace aging infrastructure and

[1] Application, pp. 1-2. (January 9, 2014).

reduce regulatory lag. The Commission has jurisdiction over Atmos's Application under K.S.A. 66-117 and K.A.R. 82-1-231.

3. In support of its Application, Atmos submitted testimony from six witnesses and the schedules required by K.A.R. 82-1-231.

4. On January 10, 2014, the Citizens' Utility Ratepayer Board (CURB) filed a petition to intervene. On January 16, 2014, the Commission granted CURB's intervention.

5. On January 23, 2014, the Commission issued a Suspension Order suspending the Application until September 8, 2014, 240 days from the date of the Application.[2]

6. On February 12, 2014, the parties filed a Joint Motion proposing a procedural schedule and requesting a discovery order, protective order, and scheduling a hearing before the Commission. The Commission issued an order granting the Joint Motion on February 25, 2014.

7. On April 7, 2014, a public hearing was held in Overland Park, Kansas, allowing ratepayers to hear about the proposed rate increase and share their concerns with the Commission.

8. On May 20, 2014, Commission Staff (Staff) filed direct testimony from nine witnesses, recommending Atmos receive a revenue requirement increase of $4,579,953, with an ROE of 9.0%.

9. Also on May 20, 2014, CURB filed testimony from three witnesses, recommending Atmos receive a revenue increase of $1,252,274, with a ROE of 8.5%. CURB filed cross-answering testimony of one witness on May 30, 2014.

10. On June 10, 2014, Atmos filed its rebuttal testimony from seven witnesses.

11. On June 13, 2014, the parties met to discuss the possible settlement of the issues in this matter. On June 19, 2014, Atmos, Staff, and CURB (collectively the Parties) filed a Joint

[2] K.A.R. 82-1-217(a)

Motion to Approve Partial Stipulated Settlement Agreement. The Partial Stipulated Settlement Agreement (Partial Agreement) is attached as Attachment 1.

12. On June 23, 2014, Atmos submitted the testimony of Joe T. Christian, Staff submitted the testimony of Justin T. Grady, and CURB submitted the testimony of Andrea C. Crane in support of the Partial Agreement.

13. On July 1 and 2, 2014, the Commission held a hearing on the proposed Partial Agreement and the remaining contested issues. Atmos, Staff, and CURB participated in the hearing.

II. TERMS OF THE PARTIAL AGREEMENT

A. Partial Stipulated Revenue Requirement

14. The Partial Agreement resolves all of the issues except ROE, the RA, and Rate Case Expense. In resolving all of the cost of service issues except for the ROE, and depending upon what ROE is set by the Commission, the Parties agree that if the Commission were to set the ROE at CURB's recommended ROE of 8.5%, then the overall annual revenue increase would be $3.3 million plus the amount of amortized Hearing/Post Hearing Rate Case Expense approved by the Commission. If the Commission were to set the ROE at Atmos's recommended ROE of 10.53%, then the overall annual revenue increase would be $6.3 million plus the amount of amortized Hearing/Post Hearing Rate Case Expense approved by the Commission. If the Commission were to set the ROE in between CURB's recommended 8.5% and Atmos's 10.53%, then the overall annual revenue increase would fall in between $3.3 million plus the Hearing/Post Hearing Rate Case Expense approved by the Commission and the $6.3 million plus the Hearing/Post Hearing Rate Case Expense approved by the Commission. In determining the overall annual revenue increase, the Parties have reached a compromise relating to the other cost

of capital items and amount of rate base in this rate case as follows: Long Term Debt Capital Percentage: 47%; Long Term Debt Cost: 6.23%; Equity Capital Percentage: 53%; Cost of Equity, or ROE, to be determined by the Commission; amount of rate base: $177,562,733 (Staff Schedule A-2). Attached to the Partial Agreement is a Table that has been developed and agreed to by the Parties that provides the Commission with what the revenue increase would be depending upon the ROE determined by the Commission. The amount of Hearing/Post Hearing Rate Case Expense approved by the Commission would need to be added to the revenue increase number in column two of the Table to determine the total revenue increase.

B. Accounting Matters

15. For purposes of filing Atmos's Ad Valorem Tax Surcharge Rider in December 2014 and subsequent years until rebased by Atmos's next base rate case, the Parties agree that the Ad Valorem Tax expense embedded in base rates shall be $6,887,556, which includes $83,220 of capitalized expense. For purposes of calculating the December 2014 rider the Parties agree to prorate the base rate amounts between (a) ad valorem tax expense embedded in base rates for the current docket, effective with the date the rate increase is implemented; and (b) for the period between January 1, 2014, and the date the rates are made effective in this docket, the Ad Valorem Tax expense used will be the base rate amount in Atmos Energy's 2012 rate case, 12-ATMG-564-RTS.

16. For purposes of calculating Atmos's pension tracker going forward, the Parties agree that the base rates agreed to in this Agreement include the following expenses:

a. Atmos's Pension Expense for Kansas Direct: $466,502.

b. Atmos's Pension Expense for Shared Services: $270,803.

c. Atmos's Postretirement Expense for Kansas Direct: $377,773.

d. Atmos's Postretirement Expense for Shared Services: $184,982.

17. For the purpose of calculating Atmos's actual rate case expense the parties have agreed that actual rate case expense consists of two categories, a prehearing expense amount and a hearing/post hearing expense amount. The prehearing expense amount of $339,586 has been mutually determined by the parties. The hearing/post hearing expense amount is set for Commission determination.

18. Amortization periods are as follows:

a. Atmos's actual rate case expense in this docket approved by the Commission, plus remaining uncollected balance from last rate case shall be amortized over three years, or if the Commission adopts Staff's proposed rate moratorium as a condition to approval of the RA mechanism and Atmos elects to implement the RA mechanism that contains the rate moratorium condition, then the amortization period for rate case expense should reflect the rate moratorium included in the RA mechanism. If Atmos elects not to implement the RA mechanism that contains the rate moratorium condition, then the amortization period shall be three years.

b. Atmos's Pension and Postretirement trackers shall be amortized over three years, or if the Commission adopts Staff's proposed rate moratorium as a condition to approval of the RA mechanism and Atmos elects to implement the RA mechanism that contains the rate moratorium condition, then the amortization period for Pension and OPEB expense should reflect the rate moratorium included in the RA mechanism. If Atmos elects not to implement the RA mechanism that contains the rate moratorium condition, then the amortization period shall be three years.

c. In the event that there is no rate moratorium and Atmos files for an adjustment in its rates prior to the end of the three year amortization period set forth above for items identified in (a) and (b), such unamortized balance, calculated as of the end of 240 days following the filing of such rate case, shall be carried forward in the calculation and amortization of rate case costs and pension tracker costs, respectively, in the next rate case filing.

C. Class Cost of Service and Rate Design

19. The Parties agree that the rate increase should be allocated among the respective classes of customers using Staff's Class Cost of Service Study and Staff's billing determinants, and that the rate increase allocated to the facilities charge and volumetric charge shall be done in a manner that keeps the ratio of facilities charge to commodity charge the same for the residential customer class as currently recovered in Atmos's rates.

20. For Gas System Reliability Surcharge (GSRS) purposes, if the Commission accepts CURB's position that the RA Mechanism should not be approved, or Staff's position that Atmos should have both an RA Mechanism and a GSRS Mechanism, or Atmos elects not to implement the RA Mechanism because of any conditions placed on its implementation that are unacceptable to Atmos, then the Parties agree that for allocating costs among customer classes in a GSRS filing such costs shall be allocated among Atmos's class of customers based on the rate allocation approved in this rate case.

21. After taking the settlement positions into account, the parties revised their revenue requirement recommendations at the following approximate figures: Atmos - \$6.3 Million; Staff - \$4.03 Million; CURB - \$3.3 Million.[3]

III. FINDINGS AND CONCLUSIONS

A. Stipulation and Agreement

22. A unanimous settlement agreement is one entered into by all parties or not opposed by any party.[4] In this case, Atmos, CURB, and Staff are all signatories to the Partial

---

[3] Staff's Post Hearing Brief in Support of the Settlement Agreement, p. 7 (July 28, 2014).

Agreement. Therefore, the proposed Partial Agreement is a unanimous settlement agreement. Even in the case of non-unanimous settlement agreements, the Commission may approve the agreement provided the Commission makes an independent finding, which is supported by substantial evidence on the record as a whole, and results in just and reasonable rates.[5]

23. Generally, Kansas law encourages settlement.[6] Settlements are beneficial when the parties agree upon a rate which is in the public interest, and without the expense of litigation.[7]

24. The Commission is charged with determining whether rates for natural gas public utilities are just and reasonable.[8] In making that determination, the Commission's goal should be to set a rate fixed within the "zone of reasonableness" after applying a balancing test which weighs the interests of all concerned parties.[9] The interests of (1) the utility's investors vs. ratepayers; (2) present vs. future ratepayers; and (3) the public interest must be weighed when determining whether a rate is in the "zone of reasonableness."[10]

25. The Commission must find that the settlement is supported by substantial, competent evidence based on the record as a whole. In an earlier rate case involving Atmos, Docket No. 08-ATMG-280-RTS, the Commission established a five factor test to evaluate proposed settlement agreements. The five factors are: (1) Did opposing parties have an opportunity to be heard and offer their grounds for opposition; (2) Is the stipulation supported by substantial, competent evidence; (3) Does the stipulation and agreement conform with

---

[4] K.A.R. 82-1-230a(2).
[5] *Farmland Industries, Inc. v. Kansas Corp. Comm'n,* 24 Kan. App.2d 172, 186, 943 P.2d 470, 484, *rev. denied,* 263 Kan. 885 (1997).
[6] *Bright v. LSI Corp.,* 254 Kan. 853, 858, 869 P.2d 686, 690 (1994).
[7] *Farmland Industries,* 24 Kan. App.2d at 195, 943 P.2d at 489.
[8] K.S.A. 66-1,202.
[9] *Kansas Gas & Elec. Co. v. State Corp. Comm'n,* 239 Kan. 483, 491, 720 P.2d 1063, 1072 (1986).
[10] *Id.*

applicable law; (4) Does the stipulation and agreement result in just and reasonable rates; and (5) Is the stipulation and agreement in the public interest. [11]

26. Because the Partial Agreement is supported or unopposed by all parties, there are no parties opposing the settlement. Therefore, the first factor is not applicable to this proceeding. Nevertheless, the record indicates all parties actively participated in all aspects of the docket. Finally, the Commission conducted a hearing at which all parties had an opportunity to be heard.

27. Because there are no parties in opposition to the Partial Agreement, this factor is not applicable. The Commission finds that no parties oppose the Partial Agreement, and all parties had an opportunity to be heard on the settlement.

28. Substantial competent evidence is that which possesses something of substance and relevant consequence, and which furnishes a substantial basis of fact from which the issues tendered can reasonably be resolved.[12] Whether another trier of fact or another party could have reached a different conclusion given the same facts is irrelevant; a court can only find that a Commission decision is not supported by substantial competent evidence when the evidence shows, "the [Commission's] determination 'is so wide of the mark as to be outside the realm of fair debate.'"[13]

29. The Partial Agreement is supported by substantial, competent evidence.[14] The parties prefiled direct testimony from eighteen witnesses, including six on behalf of Atmos, three on behalf of CURB, and nine on behalf of Staff. The parties also prefiled schedules, cross-

[11] Docket No. 08-ATMG-280-RTS, Order Approving Contested Settlement Agreement, ¶ 11 (May 12, 2008).
[12] *Kan. Gas & Elec. v. State Corp. Comm'n,* 14 Kan. App. 2d 527, 532 (1990) (quoting *SW Bell Tel. Co. v. State Corp. Comm'n,* 242 Kan. App. 2d 44, 46 (1979), *rev. denied* 227 Kan. 927 (1980)).
[13] *Zinke & Trumbo, Ltd. v. State Corp. Comm'n,* 242 Kan. 470, 474 (1988).
[14] Justin T. Grady Testimony in Support of Partial Settlement Agreement, p.6 (June 23, 2014) (Grady Support); Testimony of Andrea C. Crane in Support of Partial Stipulated Settlement Agreement, p. 8 (June 23, 2014) (Crane Support); Testimony in Support of Partial Stipulated Settlement Agreement of Joe T. Christian, pp. 8-9 (June 23, 2014) (Christian Support).

answering testimony, and rebuttal testimony. All of the prefiled testimony was entered into the record and reviewed by the Commission.

30. The Commission also received prefiled testimony and heard live testimony in support of the proposed Partial Agreement. The Commission finds the testimony filed by Joe Christian, Andrea Crane, and Justin Grady to be credible and to be supportive of adoption of the Partial Agreement.

31. "An Order is 'lawful' if it is within the statutory authority of the commission, and if the prescribed statutory and procedural rules are followed in making the Order."[15]

32. The Partial Agreement meets this test. The Partial Agreement deals with the setting of rates. Thus, the subject matter of the Partial Agreement is within the Commission's authority.

33. Additionally, the applicable statutory and procedural rules have been followed. The Partial Agreement is the result of negotiations among and is supported by all of the Parties to this proceeding. All of the Parties have had the opportunity to engage in extensive discovery and have had the opportunity to present evidence both as to Atmos's original filing and the Partial Agreement. Furthermore, there is nothing in the evidentiary record that suggests the terms of the Partial Agreement violate any applicable laws or regulations.

34. After a review of the Partial Agreement negotiated by the Parties, the Commission finds it conforms to applicable law.

35. The Partial Agreement will result in just and reasonable rates. Rates are "just and reasonable" when they reflect a reasonable balance between consumer and investor interests

[15] *Central Kansas Power Co. v. State Corp. Comm'n*, 221 Kan. 505, Syl. 1 (1977).

and provide the utility an opportunity to earn a reasonable return on its property dedicated to the public service.[16]

36. In evaluating whether rates are just and reasonable, the Commission takes into account the various interests of the parties to determine whether the proposed rates are within a "zone of reasonableness."[17] The "zone of reasonableness" is an elusive range where rates are not so high or so low as to be unlawful, and is a matter for Commission determination.[18]

37. Staff, CURB, and Atmos believe that the agreed-upon range of rates falls within the "zone of reasonableness" as defined by Kansas courts, with the caveat that the Commission will be deciding final rates by determining the return on equity in this case.[19] Under the zone of reasonableness standard, the Commission must weigh the interests of the utility's shareholders vs. the ratepayers; present vs. future ratepayers; and the public interest.[20] The proposed Partial Agreement strikes an appropriate balance between the interests of the utility shareholders and the ratepayers. Based on the record before it, the Commission finds the agreed-upon range of rates falls within the "zone of reasonableness."

38. The Partial Agreement is in the public interest. First, the interests of multiple parties are represented. CURB represents the interests of the ratepayers, Atmos represents the interests of its management and shareholders, and the Staff represents the interests of the public generally and attempts to balance the interests of all parties. Both the prefiled testimony and the testimony offered at the July 1 and 2, 2014 hearing demonstrate that the proposed Partial Agreement is in the public interest.[21]

---

[16] See, e.g., *Kansas Gas and Electric Co. v. Kan. Corp. Comm'n*, 239 Kan. 483, 489-90 (1986).
[17] *Farmland Industries, Inc. v. State Corp. Comm'n*, 24 Kan. App. 2d 172, 195 (1997).
[18] *Id.*
[19] Grady Support, p. 8; Crane Support, p. 9; Christian Support, p. 10.
[20] *Kansas Gas*, 239 Kan. at 491, 720 P.2d at 1072.
[21] Grady Support, p. 10; Crane Support, pp. 11-12; Christian Support, p. 13.

39. For the reasons stated above, the Commission finds the proposed Partial Agreement is in the public interest and should be approved.

40. The Commission concludes that settlements are favored by law.[22] A settlement of issues, all or part, with or without unanimous agreement, will be entertained by the Commission.

41. The Commission approves the Partial Agreement in its entirety. The Commission finds that all parties have had an opportunity to be heard in this proceeding and in the Partial Agreement; the Partial Agreement is supported by substantial competent evidence when viewed in light of the record as a whole; it conforms to applicable law; it will result in just and reasonable rates; and its results are in the public interest.

42. The Commission has reviewed the attached Partial Stipulated Settlement Agreement of the parties and concludes that the terms and provisions therein are an appropriate and reasonable disposition of most of the issues in this matter. The Commission therefore adopts and incorporates by reference the terms of the Stipulation and Agreement.

B. Return on Equity (ROE)

43. Atmos proposes an ROE of 10.53%.[23] Its witness, William E. Avera, testified the appropriate range for Atmos's ROE using the discounted cash flow (DCF) analysis is 8.7% to 10.5%. Avera based his ROE recommendation on the constant growth DCF model.[24] He applied the DCF model to a group of ten publicly traded gas utilities selected from those followed by *Value Line*'s Natural Gas Utility industry. He also selected and analyzed several low-risk non-utility companies using the DCF model.[25] This DCF method produced an

[22] *Bright*, 254 Kan. 853 at 858.
[23] Direct Testimony of William E. Avera and Adrien M. McKenzie, p. 4 (January 9, 2014) (Avera Direct).
[24] Avera Direct, pp. 19-20.
[25] *Id.*, pp. 48-49.

average estimated ROE of 11.4%.[26] Avera also conducted an Empirical Capital Asset Pricing Mechanism (ECAPM) analysis, a Risk Premium Method analysis, and a Capital Asset Pricing Mechanism (CAPM) analysis that yielded average estimated ROEs 12.3%, 10.1%, and 10.3%, respectively.[27]

44. Atmos also proposed a flotation cost, or equity issuance cost, of 13 to 36 basis points.[28] Avera explained flotation costs as follows:

> "The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with 'floating' the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public."[29]

45. Staff recommends an ROE of 9.0%, with a range of 8.5% to 9.5%.[30] Staff witness Adam Gatewood's ROE of 9.0% results in an overall rate of return of 7.65%.[31] To reach his recommendation, Mr. Gatewood relied on a DCF model using financial analysts' forecasted growth rates for earnings and dividends, as well as long-term growth projections for the U.S. economy from the Energy Information Agency and the Social Security Administration.[32] Gatewood used a proxy group of nine companies listed as a natural gas distribution company by *Value Line* with similar business and financial risks to Atmos.[33] Mr. Gatewood also checked his results by performing an Internal Rate of Return analysis and a CAPM study.[34] Based on his DCF analysis projecting a 8.89% mean cost of equity for Atmos, his CAPM analysis projecting a

[26] *Id.*
[27] *Id.*, pp. 32-40, 44.
[28] *Id.*, p. 43.
[29] *Id.*, pp. 40-41.
[30] Direct Testimony of Adam H. Gatewood, p. 5 (May 20, 2014) (Gatewood Direct).
[31] Gatewood Direct, p. 3.
[32] *Id.*, pp. 39-44.
[33] *Id.*, pp. 9-11.
[34] *Id.*, p. 5.

8.18% cost of equity for Atmos, and his Internal Rate of Return analysis projecting a 8.63% cost of equity for Atmos, Gatewood recommends 9.5% as the upper limit for ROE. In his testimony, Avera claimed Gatewood's analysis should have produced an ROE of 9.68% with proper calculations and more reasonable input assumptions.[35] Gatewood also proposed a flotation cost of .09% or .1%.[36]

46. CURB proposes an ROE of 8.5% and an overall rate of return of 7.39% for Atmos.[37] CURB witness Dr. Woolridge analyzed a proxy group of eight utilities using a DCF model to conclude 8.5% is the proper ROE.[38] In selecting his proxy group, Woolridge sought companies: (1) listed as natural gas distribution, transmission and/or integrated gas companies in *AUS Utility Reports*, (2) listed as a natural gas utility by *Value Line*; and (3) having an investment grade bond rating by Moody's and Standard & Poor's.[39] Woolridge also performed an ROE analysis using CAPM, which produced an ROE of 7.4%, but chose not to rely on that analysis in recommending an ROE of 8.5%.[40] Woolridge disagreed with Avera's testimony regarding the need for a flotation cost adjustment to ROE, and testified that Atmos has not shown that flotation costs are justified.[41]

47. In determining the appropriate ROE, the Commission is guided by *Federal Power Commission v. Hope Natural Gas Company,* 320 U.S. 591 (1944) and *Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923) which find returns granted to regulated public utilities should be: (1) commensurate with returns on investment of similar risk; (2) sufficient to ensure the utility's financial integrity

[35] Tr., Vol. I, p. 133 (July 1 and 2, 2014) (Avera).
[36] Gatewood Direct, pp. 5, 13-14.
[37] Direct Testimony of Dr. J. Randall Woolridge, p. 2 (May 20, 2014) (Woolridge Direct).
[38] Woolridge Direct, pp. 12-13.
[39] *Id.*
[40] *Id.*, pp. 47-48.
[41] *Id.*, pp. 72-74.

under proper management; and (3) adjusted to reflect changes in the money market and business conditions.[42] *Hope* and *Bluefield* have been adopted by the Kansas Supreme Court[43] and recognized by the Commission in numerous dockets. While the Commission has substantial discretion in setting a fair rate of return, it must not be so unreasonably high or low as to be unlawful.[44]

48. First, the Commission finds the nGDP growth estimates of 4.46% advocated by Gatewood, and consistent with the nominal forecast by the Social Security Administration and Energy Information Administration, to be more credible than the growth rate of 6.33% suggested by Avera in light of current economic conditions. This conclusion is also consistent with prior Commission decisions.

49. The Commission finds the 8.5% ROE recommended by CURB to be unreasonably low, and the current state of the economy simply does not support the 10.53% ROE which Atmos championed. The Commission further finds natural gas distribution companies are generally considered to be less risky than electric utilities.[45] This is partly due to their use of several pass-through mechanisms that tend to pass risk on to ratepayers.[46] It therefore follows that the ROE for Atmos should be lower than the 9.5% ROE this Commission granted to Kansas City Power and Light in Docket No. 12-KCPE-764-RTS.

50. After considering all of the evidence presented, the Commission adopts an ROE near the middle of Gatewood's range and just above Staff's recommendation, 9.1%. Following Staff's recommendation, this ROE should include a .10% flotation cost adjustment for equity

---

[42] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603, 64 S.Ct. 281, 288 (1944); *Bluefield Waterworks & improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679, 692-93, 43 S.Ct. 675, 679 (1923).
[43] *Kansas Gas*, 239 Kan. at 489-90, 720 P.2d at 1071.
[44] *Southwestern Bell Tel. Co. v. State Corp. Comm'n*, 192 Kan. 39, 85-86, 386 P.2d 515, 554 (1963).
[45] Tr. Vol. I, p. 57 (Avera).
[46] Gatewood Direct, pp. 31-33.

capital on top of a base ROE of 9.0%. An ROE of 9.1% is below that requested by Atmos, above that recommended by CURB, and consistent with the middle of the range suggested by Staff. The Commission finds the methods Gatewood utilized to calculate Staff's recommended ROE range to be persuasive and based on substantial competent evidence. Furthermore, the Commission finds the company may be exposed to more risk if facing the $.40 per-customer cap found in the Gas Safety and Reliability Policy Act, K.S.A. 66-2201 *et seq.* (GSRS Act) on a regular basis, and therefore an ROE slightly higher than Staff's recommendation is reasonable. Having reviewed the evidence provided by Avera, Woolridge, and Gatewood, the Commission believes an ROE of 9.1% strikes the proper balance of allowing Atmos to access capital markets while acknowledging the economic impact on ratepayers.

51. According to the table attached to the Partial Agreement, a 9.1% ROE results in a revenue requirement increase of $4,186,700 for Atmos, to which final rate case expense must be added to calculate a total revenue requirement increase.

C. Regulatory Asset

52. Included in Atmos's Application was a request for a system integrity regulatory asset (RA) to record all costs, including depreciation and taxes, incurred with respect to "system integrity projects."[47] The RA mechanism would be used in lieu of the GSRS Act currently in place in Kansas, and interest on the balance in the RA account would be recorded by Atmos based on the pre-tax cost of capital last approved for the utility until such amounts would be included in and recovered through rates in Atmos's subsequent base rate case filings.[48]

[47] Application, p.3.
[48] *Id.*, pp. 3-4.

53. Staff and CURB argued the Commission should deny Atmos's RA request. Staff argued the request is unjust and unreasonable because it is too undefined, contains no cost limitations, contains no deadlines or consequences for planning errors, does not recognize an offset for Accumulated Deferred Income Taxes (ADIT), and would improperly calculate carrying costs based upon a pre-tax cost of capital.[49] CURB argued the Commission should deny the RA request because the legislature has already responded to natural gas utilities' requests for relief from regulatory lag in recovering the cost of system integrity improvements by enacting the GSRS Act, and Atmos should not be permitted to create its own mechanism that provides more relief from regulatory lag than the legislature intended to provide.[50]

54. Atmos argued the GSRS Act does not preclude the Commission from approving other alternative rate mechanisms to cover cost recovery for pipeline projects, does not preclude natural gas utilities from requesting some other type of recovery mechanism, or that the GSRS surcharge was the only mechanism that could be approved by the Commission with respect to pipeline replacement.[51] Atmos further argued it has demonstrated a need for the RA mechanism to accelerate the replacement of aging infrastructure and remove the disincentive of the regulatory lag built into the traditional ratemaking process to encourage the replacement of aging pipe and assist Atmos in paying for such a plan.[52]

55. The Commission finds and concludes the RA proposed by Atmos in this case is too broad, poorly defined, and ambiguous to be reasonably considered by this Commission and is furthermore unnecessary in light of the current GSRS Act as enacted by the legislature. The Commission finds the best method to implement an expansion to the GSRS Act is through the

[49] Staff's Post Hearing Brief in Support of the Settlement Agreement, p. 17 (July 28, 2014).
[50] CURB's Brief on Contested Issues, p. 22 (July 28, 2014).
[51] Post Hearing Brief of Atmos Energy, p. 53 (July 17, 2014).
[52] *Id.*, p. 55.

legislative process, not through a decision from this Commission in this case. Therefore, the portion of Atmos's Application which requests the system integrity RA is hereby denied.

56. The Commission would, however, entertain the possibility of roundtable discussions with industry to discuss proposing to the legislature either an adjustment to the GSRS Act or an additional system integrity RA as well as any specific projects, goals, and concerns that it would address. Additionally, the Commission finds its decision on the RA in this case does not prevent its consideration of other infrastructure improvement mechanisms which Atmos or other utilities may propose in the future.

D. Rate Case Expense

57. The parties presented final rate case expense statements to the Commission for expenses incurred since April 2014.[53] In its August 29, 2014 filing, Staff indicated a total increase in all parties' rate case expenses of $144,800 was appropriate after amortizing the total rate case expense of $773,986 over three years and accounting for the $113,195 already included in the Partial Agreement.

58. The general rule is that prudently incurred rate case expenses are among the reasonably necessary expenses that a public utility is entitled to recover in a rate-making proceeding.[54] There was no evidence presented to suggest any of the rate case expenses incurred by the parties was imprudent. The Commission therefore concludes a rate case expense increase of $144,800 should be and is therefore included in the increase to the revenue requirement. The total revenue requirement increase approved for Atmos Energy in this docket is therefore $4,331,500.

---

[53] Atmos Late-Filed Exhibit 15 (August 5, 2014); CURB Final Rate Case Expense Letter (August 5, 2014); CURB Final Rate Case Consultant Expense Letter (August 18, 2014); Notice of Filing of Staff's Updated Rate Case Expense Report (August 29, 2014).

[54] *Kansas Industrial Consumers Group, et al v. State Corp. Comm'n of the State of Kansas*, 36 Kan. App. 2d 83, 111, 138 P.3d 338 (2006).

59. Finally, the Commission wishes to make known its concern about incurring rate case expenses in rate cases filed every two years, as has been Atmos's practice in recent years. As these expenses are borne by ratepayers, the Commission desires to ensure no rate case expense is unnecessary. To this end, in future rate case filings, the Commission may inquire into whether a two-year interval for rate cases is reasonable and whether rate case expenses are prudently incurred when the rate cases are filed relatively close together.

IT IS, THEREFORE, BY THE COMMISSION ORDERED:

A. The Commission grants the Joint Motion to Approve Partial Stipulated Settlement Agreement in this docket. The terms of the attached Partial Stipulated Settlement Agreement are incorporated into this Order.

B. The Commission concludes a Return on Equity of 9.1% is appropriate for Atmos Energy in this case. The Commission therefore approves a revenue requirement increase of $4,186,700 for Atmos Energy.

C. The Commission denies Atmos Energy's request for a Regulatory Asset to replace aging infrastructure.

D. The Commission concludes the rate case expenses presented by the parties to be reasonable and are to be included in the approved revenue requirement, amortized over the three-year period as agreed to by the parties. The total revenue requirement increase approved for Atmos Energy in this docket is therefore $4,331,500.

E. The parties have fifteen days from the date this Order was electronically served in which to petition the Commission for reconsideration.[55]

[55] K.S.A. 66-118b; K.S.A. 2013 Supp. 77-529(a)(1).

F. The Commission retains jurisdiction over the subject matter and parties for the purpose of entering such further orders as it deems necessary.

BY THE COMMISSION IT IS SO ORDERED.

Albrecht, Chair; Emler, Commissioner; Apple, Commissioner.

Dated: SEP 0 4 2014

ORDER MAILED SEP 0 4 2014

Thomas A. Day
Acting Executive Director

JV

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Atmos Energy for Adjustment of its Natural Gas Rates in the State of Kansas.	)))	Docket No. 14-ATMG-320-RTS

PARTIAL STIPULATED SETTLEMENT AGREEMENT

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

I. ATMOS ENERGY'S APPLICATION

1. On January 9, 2014, Atmos Energy filed an application with the Commission to make certain changes in its rates and charges for natural gas service, which was docketed as the above captioned proceeding. Pursuant to the Commission's Order dated January 23, 2014, the effective date of this Application was suspended until September 8, 2014. On February 25, 2014, the Commission issued an Order that established a procedural schedule. This matter is currently set for hearing on July 1-3, 2014.

2. The schedules filed with Atmos Energy's Application indicated a gross revenue deficiency of $8,765,342 based upon normalized operating results for the 12 months ending September 30, 2013, adjusted for known and measurable changes in revenues, operating and maintenance expenses, cost of capital and taxes, and other adjustments. In its Application, Atmos Energy proposed to establish and include in rate base a regulatory asset to record all costs (including related depreciation and taxes) incurred with respect to system integrity projects. This

Regulatory Asset ("RA") mechanism would be used by Atmos Energy in lieu of the Gas System Reliability Surcharge ("GSRS") tariff. Interest on the balance in the regulatory asset account would be recorded by Atmos Energy based on the pre-tax cost of capital last approved for the utility until such amounts would be included and recovered through rates in Atmos Energy's subsequent base rate case filings. Atmos Energy proposed that its return on equity ("ROE") be set at 10.53%.

3. In support of its Application, Atmos Energy submitted the testimony of 6 witnesses and the schedules required by K.A.R. 82-1-231.

4. The following parties have requested and been granted intervention in this proceeding: CURB.

II. STAFF AND CURB'S PRE-FILED POSITIONS

5. On May 20, 2014, Staff filed its direct testimony in the above docket, recommending a rate increase of $4,579,953 for Atmos Energy. Staff recommended approval of the RA mechanism provided that the Commission make certain adjustments to the proposed mechanism and place certain conditions on its approval of the RA mechanism. Staff recommended the ROE be set at 9.0%.

6. Also, on May 20, 2014, CURB filed testimony in which it recommended a rate increase of $1,252,274. CURB opposed Atmos Energy's proposed RA mechanism. CURB recommended setting the ROE at 8.5%. On May 30, 2014, CURB filed cross-testimony in response to Staff's recommendations regarding Atmos Energy's proposed RA mechanism.

7. Atmos Energy filed rebuttal testimony on June 10, 2014.

8. Subsequently, on June 13, 2014, Atmos Energy, Staff and CURB met to discuss the possible settlement of the issues in this matter. On June 18, 2014, the signatory parties were

able to reach a partial unanimous settlement agreement resolving all issues in this case except for the following non-settled issues, which shall be submitted to the Commission for their decision at the evidentiary hearing beginning July 1, 2014:

(1) What ROE should be set for Atmos Energy?

(2) Whether Atmos Energy's proposed RA Mechanism should be approved, and if it should be approved, then what terms and conditions should be included in the mechanism?

(3) What is the amount of rate case expense incurred by Atmos Energy after April 8, 2014, and Staff and CURB after April 24, 2014, ("Hearing/Post Hearing Rate Case Expense") that should be included in the rate increase?

III. PARTIAL SETTLEMENT PROVISIONS

A. Partial Stipulated Revenue Requirement

9. In resolving all of the cost of service issues except for the ROE, and depending upon what ROE is set by the Commission, the Parties agree that if the Commission were to set the ROE at CURB's recommended ROE of 8.5%, then the overall annual revenue increase would be $3.3 million plus the amount of amortized Hearing/Post Hearing Rate Case Expense approved by the Commission. If the Commission were to set the ROE at Atmos Energy's recommended ROE of 10.53%, then the overall annual revenue increase would be $6.3 million plus the amount of amortized Hearing/Post Hearing Rate Case Expense approved by the Commission. If the Commission were to set the ROE in between CURB's recommended 8.5% and Atmos Energy's 10.53%, then the overall annual revenue increase would fall in between $3.3 million plus the Hearing/Post Hearing Rate Case Expense approved by the Commission and the $6.3 million plus the Hearing/Post Hearing Rate Case Expense approved by the Commission.

In determining the overall annual revenue increase, the Parties have reached a compromise relating to the other cost of capital items and amount of rate base in this rate case as follows: Long Term Debt Capital Percentage: 47%; Long Term Debt Cost: 6.23%; Equity Capital Percentage: 53%; Cost of Equity, or ROE, to be determined by the Commission; amount of rate base: $177,562,733 (Staff Schedule A-2). Attached to this Agreement is a Table that has been developed and agreed to by the Parties that provides the Commission with what the revenue increase would be depending upon the ROE determined by the Commission. The amount of Hearing/Post Hearing Rate Case Expense, as that term is defined herein, approved by the Commission would need to be added to the revenue increase number in column two of the Table to determine the total revenue increase.

B. Accounting Matters

10. For purposes of filing Atmos Energy's Ad Valorem Tax Surcharge Rider in December 2014 and subsequent years until rebased by Atmos Energy's next base rate case, the Parties agree that the Ad Valorem Tax expense embedded in base rates shall be $6,887,556, which includes $83,220 of capitalized expense. For purposes of calculating the December 2014 rider the Parties agree to prorate the base rate amounts between (a) ad valorem tax expense embedded in base rates for the current docket, effective with the date the rate increase is implemented; and (b) for the period between January 1, 2014, and the date the rates are made effective in this docket, the Ad Valorem Tax expense used will be the base rate amount in Atmos Energy's 2012 rate case, 12-ATMG-564-RTS.

11. For purposes of calculating Atmos Energy's pension tracker going forward, the Parties agree that the base rates agreed to in this Agreement include the following expenses:

a. Atmos Energy's Pension Expense for Kansas Direct: $466,502.

b. Atmos Energy's Pension Expense for Shared Services: $270,803.

c. Atmos Energy's Postretirement Expense for Kansas Direct: $377,773.

d. Atmos Energy's Postretirement Expense for Shared Services: $184,982.

12. For the purpose of calculating Atmos Energy's actual rate case expense the parties have agreed that actual rate case expense consists of two categories, a prehearing expense amount[1] and a hearing/post hearing expense amount[2]. The prehearing expense amount of $339,586 has been mutually determined by the parties. The hearing/post hearing expense amount is set for Commission determination.

13. Amortization periods are as follows:

a. Atmos Energy's actual rate case expense in this docket approved by the Commission, plus remaining uncollected balance from last rate case shall be amortized over three years,[3] or if the Commission adopts Staff's proposed rate moratorium as a condition to approval of the RA mechanism and Atmos Energy elects to implement the RA mechanism that contains the rate moratorium condition, then the amortization period for rate case expense should reflect the rate moratorium included in the RA mechanism. If Atmos Energy elects not to implement the RA mechanism that contains the rate moratorium condition, then the amortization period shall be three years.

b. Atmos Energy's Pension and Postretirement trackers – shall be amortized over three years, or if the Commission adopts Staff's proposed rate moratorium as a condition to approval of the RA mechanism and Atmos Energy elects to implement the

[1]The prehearing expense amount equates to the total rate Case expense reported in the Direct Testimony Prepared by Kristina A. Luke Fry, May 20, 2014, Exhibit KALF-5 Line 4.

[2]The post hearing expense amount equates to any Commission approved rate case expense incurred after April 8, 2014 for Atmos Energy and after April 24, 2014 for KCC Staff and CURB.

[3]The prehearing expense amount amortized over a three year period equates to $113,195 annually and has already been included in the partial stipulated annual revenue requirement.

RA mechanism that contains the rate moratorium condition, then the amortization period for Pension and OPEB expense should reflect the rate moratorium included in the RA mechanism. If Atmos Energy elects not to implement the RA mechanism that contains the rate moratorium condition, then the amortization period shall be three years.

c. In the event that there is no rate moratorium and Atmos Energy files for an adjustment in its rates prior to the end of the three year amortization period set forth above for items identified in (a) and (b), such unamortized balance, calculated as of the end of 240 days following the filing of such rate case, shall be carried forward in the calculation and amortization of rate case costs and pension tracker costs, respectively, in the next rate case filing

C. Class Cost of Service and Rate Design

14. The Parties agree that the rate increase should be allocated among the respective classes of customers using Staff's Class Cost of Service Study and Staff's billing determinants, and that the rate increase allocated to the facilities charge and volumetric charge shall be done in a manner that keeps the ratio of facilities charge to commodity charge the same for the residential customer class as currently recovered in Atmos Energy's rates.

15. For GSRS purposes, if the Commission accepts CURB's position that the RA Mechanism should not be approved, or Staff's position that Atmos Energy should have both an RA Mechanism and a GSRS Mechanism, or Atmos Energy elects not to implement the RA Mechanism because of any conditions placed on its implementation that are unacceptable to Atmos Energy, then the Parties agree that for allocating costs among customer classes in a GSRS filing such costs shall be allocated among Atmos Energy's class of customers based on the rate allocation approved in this rate case.

IV. MISCELLANEOUS PROVISIONS

A. The Commission's Rights

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

B. Parties' Rights

17. The Parties shall have the right to present pre-filed testimony in support of this Agreement. Such testimony shall be filed formally in the docket and presented by witnesses at a hearing on this Agreement. Testimony is being filed in conjunction with this Agreement by the following witnesses: (1) Atmos Energy: Mr. Joe Christian; (2) Staff: Mr. Justin Grady; and (3) CURB: Ms. Andrea Crane.

C. Waiver of Cross-Examination of Some Witnesses; Witnesses Who Will Testify at Evidentiary Hearing

18. The Parties waive cross-examination on all testimony filed prior to the filing of this Agreement relating to the settled issues. The Parties agree that all pre-filed testimony related to the settled issues may be incorporated into the record without objection. As indicated above, the non-settled issues are (1) ROE; (2) RA Mechanism and (3) Rate Case Expense. The witnesses presented by each Party on each of the non-settled issues will be as follows:

a. ROE

Atmos Energy:	Dr. William Avera/Mr. Adrian McKenzie
Staff:	Mr. Adam Gatewood
CURB:	Dr. Randall Woolridge

b. RA Mechanism

Atmos Energy:	Mr. Bart Armstrong and Mr. Joe Christian
Staff:	Mr. Leo Haynos and Mr. Justin Grady
CURB:	Ms. Andrea Crane

c. Rate Case Expense:

Atmos Energy:	Mr. Joe Christian
Staff:	Ms. Kristina Luke Fry
CURB:	Ms. Andrea Crane

The Parties specifically reserve their rights to cross-examine the above-mentioned witnesses with respect to the non-settled issues.

D. Negotiated Settlement

19. This Agreement represents a negotiated settlement that fully resolves the settled issues in this docket among the Parties. The Parties represent that the terms of this Agreement constitute a fair and reasonable resolution of the settled issues addressed herein. Except as specified herein, the Parties shall not be prejudiced, bound by, or in any way affected by the terms of this Agreement (a) in any future proceeding; (b) in any proceeding currently pending under a separate docket; and/or (c) in this proceeding should the Commission decide not to approve this Agreement in the instant proceeding. If the Commission accepts this Agreement in its entirety and incorporates the same into a final order without material modification, the parties shall be bound by its terms and the Commission's order incorporating its terms as to all settled issues addressed herein and in accordance with the terms hereof, and will not appeal the Commission's order as it relates to the settled issues contained herein. With respect to the non-settled issues identified in paragraph 8 herein, the Parties specifically reserve all of their rights to

fully litigate those non-settled issues, including but not limited to, litigating the non-settled issues at the scheduled evidentiary hearing, cross-examination of the witnesses identified in paragraph 17 herein with respect to the non-settled issues, submitting post hearing briefs to the Commission, asking for reconsideration of the Commission order as it relates to the non-settled issues and appealing the Commission's order as it relates to the non-settled issues.

E. Interdependent Provisions

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

F. Submission of Documents to the Commission or Staff

21. To the extent this Agreement provides for information, documents or other data to be furnished to the Commission or Staff, such information, documents or data shall be filed with the Commission and a copy served upon the Commission's Director of Utilities. Such information, documents, or data shall be marked and identified with the docket number of this proceeding. Each Party agrees to submit at the evidentiary hearing a document showing actual Rate Case Expense through June 30, 2014, incurred by them that were not included by Ms. Luke Fry in her adjustment, and to submit at the time they file their post hearing briefs (Atmos Energy may include an estimate for the cost of preparing its Reply Brief) Rate Case Expense incurred by them with respect to the evidentiary hearing and briefing stages of this rate case.

IN WITNESS WHEREOF, the Parties have executed and approved this Partial Settlement Agreement, effective as of the 18th day of June, 2014, by subscribing their signatures below.

By: Saml Feather

Samuel Feather #25475
Litigation Counsel
Michael Neeley #25027
Litigation Counsel
Kansas Corporation Commission
1500 S.W. Arrowhead Road
Topeka, Kansas 66604-4027
ATTORNEYS FOR STAFF

By: ________________________

James G. Flaherty #11177
Anderson & Byrd, LLP
216 S. Hickory, P.O. Box 17
Ottawa, Kansas 66067
ATTORNEYS FOR ATMOS ENERGY

By: ________________________

David Springe #156619
Niki Christopher #19311
Citizens Utility Ratepayer Board
1500 S.W. Arrowhead Road
Topeka, Kansas 66604
ATTORNEYS FOR CURB

IN WITNESS WHEREOF, the Parties have executed and approved this Partial Settlement Agreement, effective as of the 18th day of June, 2014, by subscribing their signatures below.

By: ______________________________

Samuel Feather #25475
Litigation Counsel
Michael Neeley #25027
Litigation Counsel
Kansas Corporation Commission
1500 S.W. Arrowhead Road
Topeka, Kansas 66604-4027
ATTORNEYS FOR STAFF

By: ______________________________

James G. Flaherty #11177
Anderson & Byrd, LLP
216 S. Hickory, P.O. Box 17
Ottawa, Kansas 66067
ATTORNEYS FOR ATMOS ENERGY

By: ______________________________

David Springe #156619
Niki Christopher #19311
Citizens Utility Ratepayer Board
1500 S.W. Arrowhead Road
Topeka, Kansas 66604
ATTORNEYS FOR CURB

IN WITNESS WHEREOF, the Parties have executed and approved this Partial Settlement Agreement, effective as of the 18th day of June, 2014, by subscribing their signatures below.

By: ______________________________

Samuel Feather #25475
Litigation Counsel
Michael Neeley #25027
Litigation Counsel
Kansas Corporation Commission
1500 S.W. Arrowhead Road
Topeka, Kansas 66604-4027
ATTORNEYS FOR STAFF

By: ______________________________

James G. Flaherty #11177
Anderson & Byrd, LLP
216 S. Hickory, P.O. Box 17
Ottawa, Kansas 66067
ATTORNEYS FOR ATMOS ENERGY

By: ______________________________

David Springe #156619
Niki Christopher #19311
Citizens Utility Ratepayer Board
1500 S.W. Arrowhead Road
Topeka, Kansas 66604
ATTORNEYS FOR CURB

ROE	Revenue Requirement
10.53%	$6,300,000
10.50%	$6,255,665
10.40%	$6,107,882
10.30%	$5,960,099
10.20%	$5,812,315
10.10%	$5,664,532
10.00%	$5,516,749
9.90%	$5,368,966
9.80%	$5,221,182
9.70%	$5,073,399
9.60%	$4,925,616
9.50%	$4,777,833
9.40%	$4,630,049
9.30%	$4,482,266
9.20%	$4,334,483
9.10%	$4,186,700
9.00%	$4,038,916
8.90%	$3,891,133
8.80%	$3,743,350
8.70%	$3,595,567
8.60%	$3,447,783
8.50%	$3,300,000

SEP 0 4 2014

CERTIFICATE OF SERVICE

14-ATMG-320-RTS

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing Order Approving Partial Stipulated Settlement Agreement; Order on Contested Issues was served by electronic mail this 4th day of September, 2014, to the following parties who have waived receipt of follow-up hard copies:

JAMES G. FLAHERTY, ATTORNEY
ANDERSON & BYRD, L.L.P.
216 S HICKORY
PO BOX 17
OTTAWA, KS 66067
Fax: 785-242-1279
jflaherty@andersonbyrd.com

JAMES PRICE, ATTORNEY
ATMOS ENERGY
5430 LBJ FREEWAY, THREE LINCOLN CENTRE
PO BOX 650205
DALLAS, TX 75265-0205
james.price@atmosenergy.com

BARTON W. ARMSTRONG, VICE PRESIDENT, OPERATIONS
ATMOS ENERGY CORPORATION
25090 W 110TH TERR
OLATHE, KS 66061
bart.armstrong@atmosenergy.com

DOUGLAS C. WALTHER, ASSOCIATE GENERAL COUNSEL
ATMOS ENERGY CORPORATION
5420 LBJ FWY STE 1600 (75240)
P O BOX 650205
DALLAS, TX 75265-0205
douglas.walther@atmosenergy.com

KAREN P. WILKES, VICE PRESIDENT, REGULATORY AND PUBLIC AFFAIRS
ATMOS ENERGY CORPORATION
1555 BLAKE ST STE 400
DENVER, CO 80202
karen.wilkes@atmosenergy.com

NIKI CHRISTOPHER, ATTORNEY
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3116
n.christopher@curb.kansas.gov

DELLA SMITH
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3116
d.smith@curb.kansas.gov

SHONDA SMITH
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3116
sd.smith@curb.kansas.gov

DAVID SPRINGE, CONSUMER COUNSEL
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3116
d.springe@curb.kansas.gov

SAMUEL FEATHER, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027
Fax: 785-271-3167
s.feather@kcc.ks.gov

ORDER MAILED SEP 0 4 2014

SEP 04 2014

CERTIFICATE OF SERVICE

14-ATMG-320-RTS

MICHAEL NEELEY, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027
Fax: 785-271-3167
m.neeley@kcc.ks.gov

JAY VAN BLARICUM, ASSISTANT GENERAL COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027
Fax: 785-271-3314
j.vanblaricum@kcc.ks.gov

Sheryl L. Sparks

Sheryl L. Sparks
Administrative Specialist

ORDER MAILED SEP 04 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES AND TARIFF MODIFICATIONS	)))	CASE NO. 2013-00148

TABLE OF CONTENTS

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES AND TARIFF MODIFICATIONS	)))	CASE NO. 2013-00148

ORDER

Atmos Energy Corporation ("Atmos"), a gas distribution company operating in eight states, serves roughly 3.1 million customers. Its Kentucky/Mid-States division, one of six operating divisions, provides natural gas service in Kentucky, Tennessee and Virginia. Atmos's Kentucky unit ("Atmos-Ky.") serves approximately 173,000 customers in 38 central and western counties in Kentucky. The most recent adjustment of its Kentucky operating unit's base rates was in May 2010 in Case No. 2009-00354.[1]

BACKGROUND

On May 13, 2013, Atmos-Ky. submitted its application based on a forecasted test period ending November 30, 2014, seeking an increase in revenues of $13,367,575, or 8.6 percent, with a proposed effective date of June 13, 2013.

A review of the application revealed that it did not meet the minimum filing requirements of 807 KAR 5:001, Sections 4 and 16, and a notice of filing deficiencies was issued. Atmos-Ky. filed information on May 30, 2013, and June 3, 2013, to cure

[1] Case No. 2009-00354, *Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 28, 2010).

the noted filing deficiencies. Our June 24, 2013 Order found that this information satisfied all of the filing requirements cited in our deficiency notice except the requirement for Atmos-Ky. to post its application and other documents on its website. The Commission found that this deficiency would remain until Atmos-Ky. provided proof that it had posted its application and other documents filed with its application on its website. Atmos-Ky. responded to that Order that same day by providing a copy of the page that had been posted on its website listing the documents. A notice that Atmos-Ky.'s deficiencies had been cured was issued June 26, 2013, stating that that the application met the minimum filing requirements as of June 24, 2013. Based on a June 24, 2013 filing date, the earliest possible date Atmos-Ky.'s proposed rates could become effective was July 24, 2013.

The Commission found that an investigation would be necessary to determine the reasonableness of Atmos-Ky.'s proposed rates and suspended them for six months, from July 24, 2013, up to and including January 23, 2014, pursuant to KRS 278.190(2). The suspension Order included a procedural schedule which provided for discovery on the application, intervenor testimony, discovery on any intervenor testimony, rebuttal testimony by Atmos-Ky., a public hearing, and an opportunity to file post-hearing briefs.

Petitions to intervene were filed by the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"), Kentucky Industrial Utility Customers, Inc. ("KIUC"), and Stand Energy Corporation ("Stand").[2] The AG was granted full intervention and Stand was granted full intervention, limited to participation on the issues of Atmos-Ky.'s transportation threshold levels and any matters related

[2] KIUC later withdrew its petition to intervene.

thereto. Discovery was conducted on Atmos-Ky.'s application by both the AG and the Commission Staff ("Staff"). The AG filed testimony on which discovery was conducted by both Atmos-Ky. and Staff. Atmos-Ky. filed rebuttal testimony and the AG filed supplemental testimony in response to which Atmos-Ky. filed surrebuttal testimony. Stand filed no testimony.

Pursuant to KRS 278.190(2), Atmos-Ky. gave notice on January 22, 2014, of its intent to place its proposed rates in effect for service rendered on and after January 24, 2014. In our January 28, 2014 Order, we acknowledged that Atmos-Ky. had complied with the statutory provisions for placing its proposed rates in effect. That Order required that Atmos-Ky. maintain its records so that, in the event a refund were to be required, the amount of refunds and the customers to whom the refunds should be applied could be determined.

The Commission held an evidentiary hearing on the proposed rate adjustment on December 3, 2013 and January 23, 2014, at its offices in Frankfort, Kentucky. Post-hearing briefs were filed by Atmos-Ky., the AG, and Stand. All information requested at the formal hearing has been filed and the case now stands submitted for a decision. As discussed more thoroughly throughout this Order, the Commission is granting Atmos-Ky. a base-rate increase of $8,550,134, which is roughly 64 percent of what it requested and which represents an increase in total revenues of approximately 5.5 percent.

TEST PERIOD

Atmos-Ky. proposed the 12 months ending November 30, 2014, as its forecasted test period to determine the reasonableness of its proposed rates. While the AG did not object to the proposed test period or suggest an alternative test period, he criticized

Atmos-Ky.'s development of certain items contained in its proposed test period. The AG raised concerns with Atmos-Ky.'s forecasted filing regarding its lack of documentation, methodology, and specific impacts on costs.[3] The AG stated that he did not agree with using a forecasted test period, but that Atmos-Ky. did not respond adequately to certain data requests he propounded to elicit information that would have permitted a more thorough review of the data supporting the forecasted test period.[4]

Atmos-Ky. stated that its development of a forecasted test period begins with its budget, which it prepares annually for its October 1 to September 30 fiscal year. It described the numerous approvals to which its budgets are subjected, including the final review by the Atmos Board of Directors. Atmos-Ky. noted that, along with its Kentucky operations, Atmos maintains a Division General Office ("DGO") that manages utility operations in the states, including Kentucky, which make up the Kentucky/Mid-States division. It further noted that Atmos has a Shared Services Unit ("SSU") which provides support services such as accounting, billing, tax, call center, collections, etc., to the various operating divisions. Atmos-Ky. stated that separate budgets are developed each year at the Kentucky, DGO, and SSU levels.

The Commission finds Atmos-Ky.'s forecasted test period to be reasonable and consistent with the provisions of KRS 278.192 and Kentucky Administrative Regulation

[3] Direct Testimony of Bion C. Ostrander ("Ostrander Testimony") at 6.

[4] *Id.* at 7, 13, and 14.

5:001, Section 16 (6), (7), and (8). Therefore, we will accept the forecasted test period as proposed by Atmos-Ky. for use in this proceeding.[5]

VALUATION

Rate Base

Atmos-Ky. proposed a net investment rate base for its forecasted test period of $252,914,292 based on the 13-month average for that period.

The AG proposed to reduce Atmos-Ky.'s rate base to eliminate Net Operating Loss Carry-forwards ("NOLC") resulting from the losses reported by Atmos's regulated operations for tax purposes.[6] The AG stated that while he had no concerns with typical accumulated deferred income taxes ("ADIT") used to reduce rate base, an NOLC debit is an offset to the typical credit balance in ADIT, causing an increase in rate base.[7]

The AG opined that removing the NOLC from rate base would not cause a tax normalization violation.[8] In support of his recommendation, the AG cited a recent case before the West Virginia Commission in which Mountaineer Gas's proposal to include a NOLC in its rate base was denied.[9] If there was substantive disagreement by Atmos-

[5] Contrary to his contentions, we find that the AG had adequate opportunity to conduct discovery for the purpose of analyzing the proposed test period and components thereof. The Commission notes that the use of a forecasted test period is provided for in 807 KAR 5:001, Section 16. We also note that the criticism by AG witness Ostrander to the use of a forecasted test period, as he has done in this case and the two recent rate cases of Big Rivers Electric Corporation, is not supported by law or regulation. The AG did not file any motions regarding discovery disputes until his motion on Nov. 21, 2013 requesting that the Dec. 3, 2013 Hearing be postponed, which the Commissioner granted.

[6] The amount the AG removed from rate base was $22,221,329, which was an estimate. Atmos-Ky. clarified that that the NOLC amount included in its rate base was $20,125,550.

[7] Ostrander Testimony at 49.

[8] *Id.* at 51.

[9] *Id.* at 55.

Ky. on the NOLC rate base issue, the AG recommended that Atmos-Ky. obtain a private-letter ruling from the Internal Revenue Service ("IRS") to resolve the issue.[10]

Atmos-Ky. claimed that removing the NOLC from rate base would result in a tax normalization violation of the Internal Revenue Code.[11] It stated that a violation would cause it to lose accelerated depreciation, bonus depreciation, and other tax benefits. Atmos-Ky. also claimed that removing NOLCs from its rate base is inappropriate and inconsistent with sound ratemaking principles, and that inclusion of NOLCs in rate base has been accepted by many commissions, including these in all other states in which Atmos's distribution companies operate.[12] It noted that the Mountaineer Gas case cited by the AG is the only instance in which a utility regulator ruled that NOLC should not be included in rate base.[13] Atmos-Ky. stated that if the Commission determined that its NOLC should remain in rate base, there was no need to involve the IRS with a private letter ruling request. However, if the Commission requires that it seek such a ruling, Atmos-Ky. asks to be allowed to create a regulatory asset to defer the costs related to such a request and seek recovery of them in its next general rate case.[14]

The Commission is not persuaded by the AG's argument. While there is some ambiguity in the Treasury regulations cited by the AG and Atmos-Ky. on the subject of NOLCs, we are unable to agree with the AG that a tax normalization violation would not

---

[10] *Id.* at 57-58.

[11] Rebuttal Testimony of Pace McDonald at 4.

[12] *Id.* at 16-19 and 22.

[13] *Id.* at 21.

[14] Atmos-Ky.'s post-hearing brief at 17.

result from a decision to remove NOLCs from Atmos-Ky.'s rate base. The AG has not made a compelling argument for why, from a ratemaking perspective, it would be reasonable to adopt his recommendation.

Although we are rejecting the AG's proposal, the aforementioned ambiguity in the governing regulations and the significantly different interpretations of those regulations by the AG and Atmos-Ky. cause the Commission to conclude that it would be beneficial to have a more definitive assessment of this issue.[15] Therefore, we find that Atmos-Ky. should seek a private-letter ruling from the IRS with the intent that such ruling be filed with the application in Atmos-Ky.'s next general rate case. We also find that Atmos-Ky. should be permitted to create a regulatory asset to defer the costs related to its private-ruling request in order to seek their recovery in its next general rate case.

Having rejected the AG's proposal to exclude the NOLC, the Commission has determined that Atmos's net investment rate base is $252,737,721 as shown below. Cash working capital has been reduced to reflect the adjustments to operation and maintenance ("O&M") expenses discussed later in this Order.

Utility Plant in Service	$	445,835,433
Construction Work In Progress		8,541,792
Total Utility Plant	$	454,377,225
LESS:		
Accumulated Depreciation	$	166,889,761
Net Utility Plant	$	287,487,464
ADD:		
Gas Stored Underground	$	9,415,216
Materials and Supplies		58,851
Prepayments		1,254,362
Working Capital		3,160,640

[15] It is possible that the NOLC issue may be at issue in future Atmos-Ky. rate cases.

Subtotal	$	13,889,069
DEDUCT:		
Customers Advances for Construction	$	2,745,576
Accumulated Deferred Income Taxes And Investment Tax Credits		45,893,236
Subtotal	$	48,638,812
NET INVESTMENT RATE BASE	$	252,737,721

CAPITAL STRUCTURE

As a division of Atmos, Atmos-Ky. does not have a stand-alone capital structure. Using Atmos's capital balances, Atmos-Ky. proposed a test-period capital structure consisting of 51.83 percent common equity and 48.17 percent long-term debt. It also presented a second capital structure for informational purposes consisting of 49.16 percent common equity, 45.68 percent long-term debt, and 5.16 percent short-term debt.[16] Atmos-Ky. stated that the capital structure containing no short-term debt was appropriate for determining its revenue requirement in that Atmos-Ky. did not use short-term debt to finance the long-lived assets in its rate base.[17]

The Commission is not persuaded by Atmos-Ky.'s reasoning for not reflecting short-term debt in its capital structure. To the extent there is a connection between long-lived assets and long-term forms of capital, the Commission has recognized that a utility's rate base includes items other than long-lived plant assets that may be financed

[16] The second capital structure reflected a short-term debt component based on the average short-term debt balance of Atmos for the 12 months ended March 31, 2013.

[17] Cross-examination of Gregory K. Waller, January 23, 2014 Hearing at 16:55:50 – 16:56:04.

with short-term debt.[18] Furthermore, while it is the intent of utilities, from a planning perspective, to finance long-lived assets with long-term forms of capital, from a practical perspective the Commission has long held the position that capital cannot be assigned directly to a particular state, jurisdiction or specific asset.[19]

In its last litigated case, Atmos-Ky., formerly Western Kentucky Gas, ("Western"), proposed a capital structure that contained no short-term debt. However, finding that "Western uses significant amounts of short-term debt on an ongoing basis..." the Commission approved a capital structure containing 8.47 percent short-term debt.[20] In the time since that case, the Commission has issued decisions in 14 litigated rate cases involving investor-owned gas or electric utilities, or combination gas and electric utilities. In 13 of those cases, the Commission authorized a capital structure containing a short-term debt component. The one exception occurred when the utility had used its short-term debt to reacquire bonds during the historical test period used in that case.[21]

Having considered Atmos-Ky.'s argument and the historical practice employed in Kentucky rate cases for more than two decades, we find that the appropriate capital structure in this matter should include a short-term debt component. Accordingly, based on the record evidence, the Commission will approve for ratemaking purposes a capital

---

[18] Case No. 8738, *An Adjustment of Rates of Columbia Gas of Kentucky* (Ky. PSC July 5, 1983) at 21.

[19] Case No. 9678, *An Adjustment of Rates of General Telephone Company of the South* (Ky. PSC Apr. 16, 1987) at 9. Case No. 10117, *Adjustment of Rates of GTE South, Inc.* (Ky. PSC Sept. 1, 1988) at 11.

[20] Case No. 90-013, *Rate Adjustment of Western Kentucky Gas Company* (Ky. PSC Sept. 13, 1990) at 19.

[21] Case No. 2009-00549, *Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates* (Ky. PSC July 30, 2010).

structure that contains 49.16 percent common equity, 45.68 percent long-term debt, and 5.16 percent short-term debt.

REVENUES AND EXPENSES

Atmos-Ky. developed an operating statement for its forecasted test period based on its budgets for fiscal years 2013 and 2014. As required by 807 KAR 5:001, Section 16(6)(a), the financial data for the forecasted test period was presented by Atmos-Ky. in the form of pro forma adjustments to its base period, the 12 months ending July 31, 2013.[22] Based on the assumptions built into its budgets, Atmos-Ky. calculated its test-year operating revenues and Operations and Maintenance ("O&M") expenses to be $155,374,969 and $141,914,890, respectively.[23] These test-year operating revenues included gas cost revenues of $90,265,243, based on Atmos-Ky.'s estimate of gas cost to be recovered through its Gas Cost Adjustment mechanism.[24]

Based on the adjusted revenues and O&M expenses stated above, Atmos-Ky.'s test-period operating income was $13,460,079, which, based on its proposed rate base, results in a 5.32 percent overall rate of return. Based on a proposed return on equity ("ROE") of 10.7 percent, Atmos-Ky. determined that it required a revenue increase of $13,367,575, which would produce an overall return on rate base of 8.53 percent.

The AG, based on a number of proposed adjustments to Atmos-Ky.'s test-period results, and a 7.63 percent overall return on rate base, calculated Atmos-Ky.'s operating

[22] Application, Vol. 9 of 9, Schedules D.1 and D.2.

[23] *Id.* Schedule C-1.

[24] In response to Item 28 of Staff's Second Request for Information (Staff's Second Request"), Atmos-Ky. updated its estimate of gas cost revenues for the test period to $111,008,901.

revenue to be $16,831,319 and recommended an increase in revenues of $1,215,895.[25] The AG later revised his recommendation, and increased the amount of the revenue increase to $2,736,433.[26]

The Commission will accept most components of Atmos-Ky.'s test period and many of its proposed adjustments. We will also accept some of the AG's proposed adjustments. A discussion of the individual adjustments accepted, modified or rejected by the Commission and the impact of those adjustments on Atmos-Ky.'s revenue requirement follows.[27]

Revenue Normalization

In normalizing test period revenues, Atmos-Ky. increased its firm sales volumes by 2,189,876 Mcf to reflect its adjustment for weather normalization based on the National Oceanic and Atmospheric Administration's ("NOAA") normal Heating Degree Day ("HDD") data for the 30-year period ending 2010.[28] It further adjusted its firm sales volumes by (427,287) Mcf to reflect changes in consumption due to a long-standing trend in conservation and efficiency by its residential, commercial, and public authority customer classes. For other classes, Atmos-Ky. adjusted customer numbers and sales and transportation volumes for known and measurable changes in service contracts and

[25] Ostrander Testimony, Exhibit BCO-2, Schedule A-1.

[26] Supplemental and Corrected Direct Testimony of Bion C. Ostrander ("Ostrander Corrected Testimony") at 2.

[27] Two AG adjustments to which Atmos-Ky. agreed on rebuttal were: a reduction in bad-debt expense of $25,048 and removal of duplicate billing systems' maintenance fees in the amount of $51,262.

[28] Direct Testimony of Mark A. Martin ("Martin Testimony"), Exhibit MAM-4.

customer usage, resulting in a decrease in interruptible sales volumes of approximately 330,000 Mcf and an increase in transportation volumes of approximately 500,000 Mcf.[29]

The Commission finds Atmos-Ky.'s adjustments to be reasonable and accepts its normalized base-rate revenues. With regard to weather normalization methodology to be used in future rate proceedings, the Commission finds that Atmos-Ky. should use the most recent temperature data available. In response to a Staff request for information, Atmos-Ky. stated its belief that there is a benefit to using NOAA's published 30-year temperature normal product, because NOAA thoroughly analyzes the data and smooths the average daily HDD to produce daily normals.[30] Because the Commission is aware that this is the case, and with the data's having been published in July 2011, it is reasonable to use the 30 years ended 2010 to weather normalize sales volumes and revenues in this case. The Commission does not believe it would be reasonable to continue to use the same 30-year period to weather normalize sales volumes and revenues in future rate proceedings brought prior to NOAA's next published 30-year temperature-normal product, and therefore, we will require that a more current time period be used. The Commission will also require that Atmos-Ky. file a comparison of weather normalization methodologies using time periods including, but not limited to, 20, 25, and 30 years in length. Along with its comparison of results, Atmos-Ky. should include support for the time period it proposes to use to normalize revenues, including the superiority of the chosen method in terms of its predictive value for future temperatures.

[29] *Id.*, Exhibit MAM-3.

[30] Response to Staff's Second Request, Item 26.

Payroll and Benefits

Atmos-Ky.'s test period includes combined direct payroll and benefits expense of $8,865,683. It also includes allocated DGO and SSU payroll and benefits expenses of $7,570,803. The AG compared these amounts to the actual fiscal year 2012 payroll and benefits expenses incurred by Atmos-Ky. and the amounts allocated to it by DGO and SSU for that period and recommended an adjustment to reduce test-period payroll and benefits expenses by one-half of the difference, or $1,212,712.[31] The AG claimed that the levels proposed by Atmos-Ky. represented significant and unusual increases for which Atmos-Ky. had failed to meet a reasonable burden of proof.[32]

Atmos-Ky. asserted that the AG's adjustment ignores the guidelines set forth in 807 KAR 5:001, Section 16(6)(a), which require that test-period adjustments are to be made to the base period. It also asserted that the AG's adjustment is founded on an arbitrary and unsupported 50 percent reduction factor.[33] Atmos-Ky. explained that the sale of Atmos's Missouri, Illinois, Iowa, and Georgia operations, all of which were part of the Kentucky/Mid-States' division, increased its share of allocated costs from both DGO and SSU, which increased its test-year payroll and benefits expense levels.[34] It stated that the payroll and benefits amounts included in its forecasted test year are consistent

[31] Ostrander Corrected Testimony at 37-38.

[32] *Id.* at 42.

[33] Surrebuttal Testimony of Joshua C. Densman ("Densman Surrebuttal") at 5-6.

[34] Rebuttal Testimony of Jason L. Schneider ("Schneider Rebuttal") at 4.

with the Commission's regulation for forecasted test periods and that said amounts are the most reasonable forecasts of payroll and benefits for the test year.[35]

The Commission does not accept the AG's recommended adjustment. While the increases in some items between Atmos-Ky.'s fiscal year 2012 and the forecasted test period are notable, it is clear that a major contributing factor was the sale of other Atmos properties, which increased the amounts allocated to Atmos-Ky. The provisions of 807 KAR 5:001, Section 16(6)(a), which dictate how an applicant utility is to present its test year when it uses a forecasted test period, do not govern nor limit an intervenor's analysis of the test year. However, the AG's use of Atmos-Ky.'s 2012 fiscal year as the benchmark to which he compared the test period is not persuasive. Furthermore, although there are instances in which a sharing by ratepayers and shareholders is the basis for reducing a cost by 50 percent for ratemaking purposes, in this instance it does not appear that such a sharing was the intent, but that the AG's use of 50 percent was arbitrary and unsupported, as Atmos-Ky. claimed. For these reasons, we reject the AG's adjustment to reduce Atmos-Ky.'s test year payroll and benefits expense.

Inflation Factor

To forecast "Other O&M" (operating expenses other than (1) labor, (2) benefits, (3) rent, maintenance and utilities, and (4) bad debt) for the test year, Atmos-Ky. applied an inflation factor of 2.7 percent using the approved expense levels in its fiscal year

[35] Densman Surrebuttal at 8-9.

2013 as the starting point.[36] This inflation factor was the average inflation rate for the Midwest region for the last three years, as reported by the U.S. Department of Labor.[37]

The AG opposed Atmos-Ky.'s use of an inflation factor to forecast test-period expenses and proposed an adjustment of $496,907 to remove the impact of inflation. The AG stated that Atmos-Ky. had not met a reasonable burden of proof regarding this item and did not show that there was a proper correlation between its generic inflation factor and the actual historic changes in the expenses to which it applied the inflation factor.[38] He argued that use of the Consumer Price Index ("CPI") was inappropriate because the ". . . CPI basket of goods and services is not representative of Atmos' expenses" and that Atmos had not addressed or reconciled this inconsistency.[39] The AG noted that his proposed adjustment reflected his belief that Atmos-Ky. had applied the inflation factor to both test-period and base-period expenses.[40]

On rebuttal, Atmos-Ky. stated that it did not apply the inflation factor to its base-period expenses. It described an error in the AG's calculation of the amount to which he applied the percent inflation factor in the test year.[41] After adjusting for these items, the correct impact of Atmos-Ky.'s use of the inflation factor is an expense increase of

---

[36] For insurance expense, Atmos-Ky. applied a 5 percent inflation factor reflect that to recent increases in insurance costs have been greater than increases in the other components of "Other O&M."

[37] Direct Testimony of Joshua C. Densman ("Densman Testimony") at 15.

[38] Ostrander Corrected Testimony at 12.

[39] *Id.* at 13.

[40] *Id.* at 16 and 22-23.

[41] Densman Rebuttal at 2-5.

$171,804.[42] Atmos-Ky. stated that use of an inflation factor for a forecasted test year is appropriate and that its methodology is consistent with what has been used in prior cases.[43]

While it has on occasion accepted inflation-related adjustments for individual expense items,[44] the Commission has not been, and is not now, inclined to accept an expense level based on application of a standard, or generic, inflation factor to a mix of approximately a dozen different cost categories ranging from Vehicles and Equipment to Travel and Entertainment. Commission orders in prior cases stated the Commission's view on this type of CPI-based proposal by finding that using the CPI relies "...upon too large and diverse a group of goods and services." In its decision involving the water rates of the city of Lawrenceburg, the Commission also stated that the adjustment proposal "...must provide an accurate measurement of changes in the cost of providing water service. It therefore should be based principally on those goods and services that are reasonably likely to be used to provide water service."[45] The Commission reasoned that a proper adjustment "...should reflect <u>all</u> changes in the cost of the inputs that are required to provide water service" (emphasis in original) and that

[42] *Id*. at 5.

[43] *Id*.

[44] Case No. 2012-00520, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Oct. 25, 2013) at 34-35.

[45] Case No. 2006-00067, *Proposed Adjustment of the Wholesale Water Rate of the City of Lawrenceburg, Kentucky* (Ky. PSC Nov. 21, 2006) at 3-4.

reliance on the CPI would "...not reflect any reductions in the cost of service, only increases."[46]

Finding no persuasive reason to depart from its previous decisions on the reasonableness of basing cost increases on a generic inflation factor, the Commission denies Atmos-Ky.'s proposal.[47] With the corrections to the AG's adjustment provided in Atmos-Ky.'s rebuttal, the result is a $171,804 reduction in test-year operating expenses.

DGO and SSU Allocated Expenses

Atmos-Ky. included $10,876,844 and $13,071,350 in allocated expenses from DGO and SSU in its base period and test period, respectively. It stated that the budget development procedures used to develop its Kentucky budget are also used to develop the budgets of DGO and SSU.[48] Atmos-Ky. explained that costs incurred at DGO and SSU are allocated according to the Cost Allocation Manual ("CAM"), which was developed by Atmos at the corporate level and which is applied uniformly for the allocation of common costs in all states in which Atmos has regulated utility operations.[49]

Based on the difference between the allocated expenses in the test year and the actual allocated expense of $10,086,333 incurred by Atmos-Ky. in its 2012 fiscal year, the AG proposed an adjustment to reduce the test-year amount by $1,492,500.[50] Citing

[46] *Id.*

[47] To reiterate something brought out in the hearing, while Atmos-Ky.'s proposal is consistent with that used in prior cases, those cases were settled and did not require a Commission decision.

[48] Densman Testimony at 7.

[49] Direct Testimony of Jason L. Schneider ("Schneider Testimony") at 14.

[50] Ostrander Corrected Testimony at 25.

the increases in DGO and SSU allocated expenses from 2012 to the test period, after Atmos-Ky. experienced three consecutive years of decreases in these expenses, the AG characterized the increases as "significant and unusual" and claimed that Atmos-Ky. did not provide adequate explanation and documentation in support of such increases.[51]

On rebuttal Atmos-Ky. asserted that the overriding reason for the increases in its share of the expenses allocated from DGO and SSU are changes in the factors used in determining the allocations among Atmos's divisions and affiliates.[52] It explained that the principal driver of changes in the allocation factors and its increased levels of DGO and SSU expenses was the 2012 sale of Atmos's Missouri, Illinois, and Iowa operations and the 2013 sale of Atmos's Georgia operations.[53] Atmos-Ky. stated that the same cost allocation methodology had been applied consistently in accordance with its CAM since the 2001 inception of the CAM.[54] It also stated that use of that methodology had resulted in decreases in allocated DGO and SSU expenses in the past.[55]

The Commission does not find the AG's position to be persuasive and will not approve his proposed adjustment. It is unfortunate for its ratepayers that Atmos-Ky.'s share of expenses incurred at the DGO and SSU levels has been increasing; however, it has adequately explained that the sale of Atmos's operations in other states, all of which were in the Kentucky/Mid-States division, caused the increases. Furthermore, it

---

[51] *Id.* at 30-32.

[52] Schneider Rebuttal at 6.

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

[54] Schneider Testimony at 14.

[55] Schneider Rebuttal at 5.

has provided the revised allocation factors on which its current allocation is based, and these support its stated position. Accordingly, the AG's proposed adjustment is denied.

Employee Incentive Pay

Atmos-Ky. included $1,164,455 in employee incentive pay in its forecasted test-period operating expenses. The incentive pay reflects the following three plans under which different groups of employees are compensated: (1) Long-Term Incentive Plan; (2) Management Incentive Plan; and (3) Variable Pay Plan.[56]

The AG recommended an adjustment that would eliminate half, or $582,228, of the incentive pay expense from rate recovery.[57] As support for his recommendation, the AG noted that all three plans awarded incentives based on a measure of earnings per share ("EPS"), meaning they were tied to financial results of which shareholders were the primary beneficiary.[58] Because the plans are focused more on shareholder-driven goals, the AG recommended that the costs be shared equally between shareholders and ratepayers, with the shareholder portion being removed for ratemaking purposes.[59]

Atmos-Ky. opposed the AG's adjustment, stating that it was not unique in making incentive compensation part of the overall compensation package offered to employees, and that its total compensation package is designed to be in the middle of the job market in which it competes for talent.[60] Atmos-Ky. claimed that its incentive pay

[56] Responses to AG-1, Items 58, 60, and 61.

[57] Ostrander Corrected Testimony at 43.

[58] *Id.* at 45.

[59] In his post-hearing brief the AG urged that we disallow any incentive compensation.

[60] Densman Rebuttal at 13.

criteria provide benefits to customers because, in order for the criteria to be met, all of its employees must work together to ensure that it operates efficiently and effectively, which translates into lower costs and lower rates for customers.[61]

The Commission is in general agreement with the AG on this matter. Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as safety, service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As noted in the hearing on this matter, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans.[62] Regarding Atmos-Ky.'s contention that customers benefit because its plans incentivize employees to work together to achieve efficiency and effectiveness, which translates into lower costs and lower rates, it is worth noting that Atmos-Ky.'s witness on this issue stated his belief that employees would strive to do what is right and do a "good job" without these additional incentives.[63] It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures and we find Atmos-Ky.'s argument to the contrary unpersuasive. Accordingly, we will remove the full amount, $1,164,455, from test-period operating expenses for ratemaking purposes.

Customer Service System ("CSS") Costs

In 2013, Atmos implemented a new CSS to replace a legacy system that had been in service since the mid-1990s. The total cost of the new CSS is approximately

[61] *Id.* at 14.

[62] Cross-examination of Joshua C. Densman, Jan. 23, 2014 Hearing at 16:24:54 – 16:28:09.

[63] *Id.* at 16:19:10 – 16:20:29.

$78.9 million, of which $4.5 million is allocated to Atmos-Ky.[64] The initial estimated cost of the system was $64 million, based on a planned two-phase implementation. Upon determining that a single-phase implementation was more favorable, Atmos revised its estimate to $72 million. Ultimately, the system's final installed cost was $78.9 million, with the additional $6.9 million largely due to the addition of internal resources needed to test the system prior to its implementation.[65]

The AG proposed an adjustment to reduce test-year expenses by $97,599 to recognize imputed cost savings related to implementing the new CSS.[66] The AG based the adjustment on estimated efficiencies and cost savings provided at Atmos Board of Director meetings, the increase in the cost of the CSS, and his belief that "Atmos must have anticipated certain quantitative and qualitative benefits related to implementation under the single stage approach (versus the 2-stage approach) and that these benefits should be shared with ratepayers. . . ."[67] The AG also proposed to reduce rate base by $426,751 to eliminate one-half of the increase in the CSS's capital cost.

Atmos-Ky. contested the AG's proposals, stating that Atmos's internal projections of potential savings made nearly four years ago should not be binding.[68] It claimed that the AG was incorrect in his assumption that the capital cost over and above the initial

---

[64] Response to AG-2, Item 36.a.

[65] Response to AG-1, Item 97.

[66] Ostrander Corrected Testimony at 49.

[67] *Id.* at 50.

[68] Atmos-Ky.'s post-hearing brief at 36.

project estimate should generate a higher level of operational efficiencies.[69] Atmos-Ky. asserted that there were two primary drivers of the increase above the original estimate of capital investment: (1) changing the implementation approach from two-phase to single-phase; and (2) the increase in internal resources above those originally estimated for testing of the system prior to its "going live."[70] It stated that the decision to alter the implementation approach and invest more in testing the system was made to ensure that the implementation was successful and seamless for customers and was not made to increase the scope of the system or add functionality to it.[71]

The Commission agrees with Atmos-Ky. that nearly four-year-old internal savings projections of the new CCS should not be binding in this situation. We find Atmos-Ky.'s explanation of the changes to the CCS project (ensuring that the implementation was successful and seamless for customers), which caused the final capital cost to exceed the initial estimate, to be reasonable. Likewise, we also find that there is inadequate support for the assumptions on which the AG's proposed adjustments are based. Therefore, the Commission will not adopt the AG's proposed expense and rate-base adjustments related to the implementation of the new CSS.

PRO FORMA ADJUSTMENTS SUMMARY

The effect of the Commission's accepted adjustments on Atmos-Ky.'s pro forma test-period operations is as follows:

---

[69] Rebuttal Testimony of Gregory K. Waller at 2.

[70] *Id.*

[71] *Id.*

	Atmos-Ky. Forecasted Test Period	Commission Accepted Adjustments	Commission Adjusted Test Period
Operating Revenues	$155,374,969	$ -0-	$ 155,374,969
Operating Expenses	141,914,891	(863,444)	141,914,447
Net Operating Income	$ 13,460,078	$ 863,444	$ 14,323,522

RATE OF RETURN

Cost of Debt

Atmos-Ky. proposed a cost of long-term debt for the test period of 6.19 percent, based on the forecast of total long-term debt expected to be in place on November 30, 2014.[72] Because Atmos-Ky. proposed to exclude short-term debt from its capital structure, it likewise did not propose to include the cost of short-term debt. Information provided in Atmos-Ky.'s application was sufficient to show that the average short-term debt for the test period is 1.25 percent.[73]

The Commission finds that the cost of long-term debt should be 6.19 percent. Consistent with its finding that short-term debt should be included in Atmos-Ky.'s capital structure, it further finds that the 1.25 percent average cost of short-term debt set out in the application should be used in calculating Atmos-Ky.'s rate of return.

Return on Equity

Atmos-Ky. recommends an ROE ranging from 10 percent to 11.3 percent, and specifically requests in its application an ROE of 10.7 percent based on its discounted cash flow model ("DCF"), the ex ante risk premium method, the ex post risk premium

[72] Application, Schedule J-3.

[73] Application, Schedule J-2.

method, and Capital Asset Pricing Model ("CAPM").[74] In its response to Item 48 of Staff's Second Request, Atmos-Ky. recommended an updated ROE of 10.6 percent.

To perform the analysis in support of Atmos-Ky.'s recommendation, Dr. James H. Vander Weide employed two comparable risk proxy groups. The first group consists of nine natural gas companies. Each company is in the natural gas distribution business; paid quarterly dividends over the last two years; had not decreased dividends over the last two years; had an available I/B/E/S long-term earnings growth estimate;[75] and was not involved in an ongoing merger. Each also has an investment grade bond rating and a *Value Line Investment Survey* ("*Value Line*") Safety Rank of 1, 2 or 3.[76] The second proxy group consists of seven water companies included in *Value Line Standard and Plus Editions* that: pay dividends; did not decrease dividends during any quarter for the past two years; have an I/B/E/S long-term growth forecast; and are not part of an ongoing merger.[77] Dr. Vander Weide stated that water utilities are included as a proxy group because the sample size of natural gas utilities is relatively small; water utilities are a reasonable proxy for investing in natural gas utilities in terms of risk; natural gas

[74] Direct Testimony of James H. Vander Weide at 3-4.

[75] *Id.* at 25. I/B/E/S, a division of Thomson Reuters, reports analysts' EPS growth forecasts for a broad group of companies. The I/B/E/S growth rates are widely circulated in the financial community, include the projections of reputable financial analysts who develop estimates of future EPS growth, are reported on a timely basis to investors, and are widely used by institutional and other investors.

[76] *Id.* at 25.

[77] *Id.* at 28.

utilities are frequently used as proxies for water utilities in water cases;[78] and that the cost-of-equity results for a group of similar-risk companies is useful to examine as a test for the reasonableness of the cost-of-equity results for natural gas utilities.

Dr. Vander Weide applied a quarterly DCF model to the gas and water proxy groups. His DCF study uses analysts' estimates of forecasted EPS growth reported by I/B/E/S and *Value Line* to compute the growth rate expected by investors. The initial DCF analysis filed in Exhibit JVW-1, Schedule I of the application sets out a "market-weighted average" for the gas proxy group utilities of 10 percent, including flotation cost. In response to a Staff information request, Atmos-Ky. stated that the simple average of the DCF analysis for the original proxy group, including flotation cost, is 9.7 percent; the market-weighted average, excluding flotation cost, is 9.7 percent; and that the simple average DCF ROE is 9.5 percent if flotation costs are excluded.[79] On November 15, 2013, Atmos-Ky. provided an update to its DCF analysis which showed a market-weighted average ROE of 9.9 percent, including flotation cost, for the eight gas proxy group utilities remaining after New Jersey Resources was excluded based on its DCF result's being so low that it failed Dr. Vander Weide's outlier test.[80] Model results for the individual companies are sufficient to show that the DCF analysis produces a simple

[78] In the final Orders in Case Nos. 2010-00036, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Dec. 14, 2010) and 2012-00520, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Oct. 25, 2013) the Commission found the use of natural gas utilities as proxies for water utilities to be inappropriate.

[79] Response to Staff's Second Request, Item 44.

[80] Atmos-Ky. Responses to Hearing Discovery Request, Question 1-10.

average ROE of 9.56 percent, including flotation cost, as updated by Atmos-Ky. on November 15, 2013, after the exclusion of New Jersey Resources' DCF result.[81]

For the water utility group, the DCF analysis produced a simple average ROE of 10.6 percent, with flotation costs, and a market-weighted average ROE of 11 percent. Atmos-Ky.'s response to Item 44 of Staff's Second Request indicated that, without flotation costs, the DCF results produced a simple average ROE of 10.4 percent and a market-weighted average ROE of 10.8 percent. Atmos-Ky.'s November 15, 2013 update showed a simple average DCF of 9.9 percent, with flotation costs, for the water group, and a market-weighted average ROE of 10.8 percent, including flotation costs.

Dr. Vander Weide relied upon data of gas distribution utilities for the ex ante risk premium ROE estimation and used a forecasted yield to maturity ("YTM") on A-rated utility bonds. The cost of equity produced by the ex ante risk premium is 11.3 percent, using a forecasted 6.55 percent forecasted YTM on A-rated utility bonds. For the ex post risk premium ROE estimation, Dr. Vander Weide relied upon stock price and dividend data from Standard & Poor's ("S&P") 500 stock portfolio and from Moody's A-rated Utility Bonds bond yield data. Using this method, the expected ROE is 10.4 to 10.9 percent with a mid-point of 10.6 percent, to which Dr. Vander Weide added an allowance for flotation cost to achieve an ROE of 10.8 percent. This calculation also included a forecasted YTM on A-rated utility bonds of 6.55 percent. In response to Item 47 of Staff's Second Request, Dr. Vander Weide confirmed that the Moody's average A-rated utility bond yield as of February 2013 was 4.18 percent. Using the 4.18 percent

[81] New Jersey Resources' DCF Model Result as shown in Exhibit JVW-1, Schedule 1, of the application is 8.3 percent.

YTM as opposed to the forecasted 6.55 percent YTM produced ROEs of 10.3 percent for the ex ante risk premium and 8.5 percent for the ex post risk premium. Dr. Vander Weide stated in his response to Item 47 that the use of the 4.18 percent bond yield produces an unreasonably low cost-of-equity estimate, and noted that as of August 14, 2013, the average utility bond yield had risen to approximately 4.9 percent. When Atmos-Ky. provided updated information to Staff's Second Request on November 15, 2013, the ROE produced by the ex ante risk premium remained unchanged at 11.3 percent, and the ROE produced by the ex post risk premium had risen to 10.9 percent, including flotation cost and using the forecasted 6.55 percent YTM.

Dr. Vander Weide performed both historical and DCF-based CAPM analyses, producing ROEs of 10.2 and 10.6 percent, respectively, using forecasts of long-term Treasury bond yields; market-weighted average betas; and including flotation cost. Atmos-Ky.'s November 15, 2013 update included CAPM analyses with more current data. The historical CAPM ROE from that updated information was 10.34 percent, while the updated DCF-based CAPM ROE was 10.8 percent, both using an updated market-weighted average beta of .74. That update included a calculation showing that the simple average beta was .69 percent. For comparison purposes, the Commission notes that substituting the simple average beta of .69 for the market-weighted average beta results in ROEs of 10.01 percent and 10.18 percent, respectively, including flotation cost, for the historical and DCF-based CAPM analyses. Dr. Vander Weide concludes in his direct testimony that the cost-of-equity model results derived from CAPM should be given less weight for purpose of estimating the cost of equity because it underestimates the cost of equity for companies with betas significantly less than 1.0.

In its post-hearing brief, Atmos-Ky. discussed the introduction of a Regulatory Research Associates ("RRA") report at the hearing which described average allowed ROE of all electric and gas utilities rate cases for 2013. It expressed concern regarding any "over reliance on a simple average return"; stated that the introduction of the report at the hearing implied that the average allowed return on equity could serve as a guide to the Commission; and enumerated the attendant problems if that were the case. Atmos-Ky. discussed in its brief the information it provided in response to Commission and Staff requests during the hearing, citing ROEs of Atmos's distribution companies on average, Atmos-Ky.'s current PRP program ROE resulting from the settlement of its last rate case, and Atmos Mississippi's ROE, all of which are currently over 10 percent.[82]

The AG's post-hearing brief referenced the ROE included in a recent settlement of an Atmos rate proceeding in Colorado, comparing the 9.72 percent ROE from that case to the 9.83 percent average ROE for gas utilities for the fourth quarter of 2013 and to the overall 2013 average ROE for gas utilities of 9.68 percent, as reported in the RRA report introduced at the hearing.[83] The AG concluded in his brief that, based on the national average allowed ROEs for gas utilities in 2013, an ROE of 9.68 percent, will provide more than a sufficient return to attract capital investment.

Having considered and weighed all the evidence in the record concerning the appropriate ROE for Atmos-Ky., the Commission finds a range of 9.3 percent to 10.3 percent to be reasonable. Within this range, an ROE of 9.8 percent will best allow Atmos-Ky. to attract capital at a reasonable cost, maintain its financial integrity to

---

[82] Atmos-Ky.'s post-hearing brief at 43-44.

[83] AG's post-hearing brief at 27.

ensure continued service, provide for necessary expansion to meet future requirements, and result in the lowest possible cost to ratepayers. In reaching our finding, we have excluded adjustments for flotation cost and have placed greater emphasis on the DCF and the CAPM model results of the gas utility proxy group. While recognizing that historical data has some value for use in obtaining estimates, we have given considerable weight to analysts' projections regarding future growth in the application of the DCF model. Finally, in assessing market expectations, we have recognized the importance of present economic conditions.

With regard to Atmos-Ky.'s concern about the aforementioned RRA report, this Commission does not rely on returns awarded in other states in determining the appropriate ROE for Kentucky jurisdictional utilities. It is reasonable to expect that other commissions, each with its own attributes, are evaluating expert witness testimony which uses the same or similar cost-of-equity models and an array of proxy groups, and reaching conclusions based on the data provided in the records of individual cases. The conclusions reached by those commissions, as well as this Commission, as to reasonable ROEs for a constantly changing group of utilities during different time periods are summarized periodically by RRA with explanatory reference points and are available to investors. To the extent that investors' expectations are influenced by such information, we believe that our 9.8 ROE will not appear unreasonable.

Rate of Return Summary

Applying Atmos-Ky.'s rates of 6.19 percent for long-term debt, 1.25 percent for short-term debt, and 9.8 percent for common equity to the approved capital structure produces an overall cost of capital of 7.71 percent. The Commission finds this overall cost of capital to be fair, just, and reasonable.

REVENUE REQUIREMENTS

Based upon Atmos-Ky.'s rate base of $252,737,721 and an overall cost of capital of 7.71 percent, the net operating income that could be justified for Atmos-Ky. is $19,486,482. Recognizing the adjustments found reasonable herein, Atmos-Ky.'s pro forma net operating income for the test year is $14,323,522. Based on the difference in these two amounts, Atmos-Ky. would need additional annual operating income of $5,189,538. After recognizing the provision for uncollectible accounts, state and federal income taxes, and the PSC Assessment, Atmos-Ky.'s revenue deficiency would be $8,550,134. The calculation of the revenue deficiency is as shown below:

Net Operating Income Deficiency	$5,189,538
Divide By Gross Up Revenue Factor	0.606954
Overall Revenue Deficiency	$8,550,134

PRICING AND TARIFF ISSUES

Cost-of-Service Study

Atmos-Ky. presented a fully allocated class cost-of-service study ("COSS") for the purpose of distributing revenue requirements among rate classes and determining rates of return on rate base at present and proposed rates for the following rate classes: Residential, Commercial and Public Authority, Firm Industrial, and Interruptible and Transportation. Atmos-Ky. revised the COSS in response to Staff's Third Information Request ("Staff's Third Request") and again when it filed its rebuttal testimony.[84]

[84] Rebuttal Testimony of Paul H. Raab ("Raab Rebuttal"), Exhibit PHR-3.

Atmos-Ky.'s revised COSS indicated that, at present rates, class rates of return on rate base are: 1.5627 percent for Residential, 10.1022 percent for Commercial and Public Authority, .6805 percent for Firm Industrial, and 26.3634 percent for Interruptible and Transportation.[85] The total company rate of return is 5.3220 percent.[86] The rates of return at Atmos-Ky.'s proposed rates would be: 4.3323 percent for Residential, 15.0922 percent for Commercial and Public Authority, 4.3633 percent for Firm Industrial, and 29.6414 percent for Interruptible and Transportation.[87] Total company rate of return on rate base would be 8.5299 percent.[88] At proposed rates, Atmos-Ky.'s COSS shows that its proposed revenue allocation results in the class rates of return moving closer to an equalized rate of return.

Atmos-Ky. filed a Customer/Demand COSS utilizing a combination of peak day demands and customer number in allocating the cost of distribution mains. Atmos-Ky. used design day demand, stating that it was the most appropriate allocation method since its "transmission plant is built to meet the highest simultaneous peak established by customers."[89] Using a zero-intercept method in developing its classification factor for distribution mains, Atmos-Ky. classified them as approximately 85 percent customer-

---

[85] *Id.* at p. 1. The COSS filed with the application shows only the Residential class providing less than the system average return at present rates. The revised COSS filed as Exhibit PHR-3 shows both the Residential and Firm Industrial classes providing less than the system average return at present rates.

[86] *Id.*

[87] *Id.*

[88] *Id.*

[89] Direct Testimony of Paul H. Raab at 9.

related and 15 percent demand-related.[90] Atmos-Ky. states that this classification is consistent with classifications it proposed and the Commission accepted in its previous rate proceedings. It also states that the Commission approved a similar zero-intercept COSS used by Delta Natural Gas Company ("Delta") in Case No. 2010-00116.[91]

The AG submitted an alternate Peak and Average COSS in the testimony of witness Glen Watkins.[92] Although certain minor differences exist between the two COSSes, Atmos-Ky. and the AG agree that the primary difference lies in the treatment of distribution mains. The AG's COSS allocates distribution mains based on both peak day and annual throughput. The AG states that the Peak and Average method is the most equitable method for assigning the costs of natural gas distribution mains because it recognizes utilization of the facilities throughout the year, but also recognizes that some classes rely on the facilities more than others during peak periods. The AG argues that in Atmos-Ky.'s COSS, 87 percent of the costs of service are allocated based on the number of customers regardless of their utilization of the system and that this places an unfair burden on residential customers.[93]

On Rebuttal, Atmos-Ky. states that its COSS recognizes that some classes rely upon the facilities more than others during peak periods because it allocates a portion of distribution mains on the basis of customer class peak demand. Atmos-Ky. contends that "each class's utilization of the Company's facilities throughout the year" has no

[90] *Id.* at 12.

[91] Case No. 2010-00116, *Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates* (Ky. PSC Oct. 21, 2010).

[92] A Peak and Average COSS is sometimes referred to as a Demand/Commodity COSS.

[93] AG's post-hearing brief at 25.

bearing on the cost being allocated. It argues that it uses a network model to plan its system which considers only the number of customers to be served and their peak demands.[94] Finally, Atmos-Ky. makes reference to page 28 of the National Association of Regulatory Utility Commissioners Manual on Gas Rate Design dated August 6, 1981, and states that the only commodity-related costs identified are those related to the acquisition of natural gas, consistent with its COSS results. Atmos-Ky. concedes that ". . . there is no 'absolute' cost of service analysis that can be relied on by the Commission in all cases to guide the allocation of costs, and that whatever cost allocation methodologies are chosen should be used as a 'guide' rather than as an absolute prescription for rate design."[95] Atmos-Ky. states, however, that when making a determination on which set of results to use as a guide in rate design, the Commission should consider whether the COSS sponsor has a particular constituency for which it is advocating. Atmos-Ky. contends that, when choosing allocators, Mr. Watkins chose those that would benefit the residential class.[96] Atmos-Ky. argues that it must take a broader view of what is fair and reasonable when making allocation decisions.

Based upon its review of Atmos-Ky.'s and the AG's COSS, the Commission finds that a Peak and Average COSS such as the AG proposed reflects a reasonable methodology. However, we also find the methodology used by Atmos-Ky. to be reasonable and, with a greater amount of detail included so that the functionalization

---

[94] Raab Rebuttal at 14.

[95] *Id.* at 4.

[96] *Id.* at 7.

and classification in its COSS could be seen, represents an acceptable starting point in determining rate design in this proceeding.

<u>Other COSS-Related Issues</u>

Atmos-Ky. acknowledged that there is support for the approach used by the AG in previously filed COSSes in other jurisdictions.[97] In addition, Atmos-Ky. stated that "[b]oth approaches utilize traditional and accepted classification and allocation methods and yet produce widely divergent results of the 'cost of service.'" It was for this reason that, in Case No. 10201,[98] the Commission encouraged Columbia to submit multiple-methodology COSSes in its future rate proceedings. The Commission reaffirmed this position in Case No. 90-013[99] when it encouraged Atmos-Ky.'s predecessor, Western, as well as other utility companies and intervenors, to file well-documented alternative and multiple-methodology COSSes to provide additional information for rate design. We continue to believe that such an approach to COSSes is appropriate and beneficial. Hence, the Commission strongly encourages Atmos-Ky. to file multiple-methodology COSSes in future rate cases in order to give the Commission a range of reasonable results for use in determining revenue allocation and rate design.[100]

[97] *Id.* at 5.

[98] Case No. 10201, *An Adjustment of Rates of Columbia Gas of Kentucky, Inc.* (Ky. PSC Oct. 21, 1988).

[99] Case No. 90-013, *Rate Adjustment of Western Kentucky Gas Company* (Ky. PSC Sept 13, 1990) at page 50.

[100] In considering methodologies, Atmos is reminded the Commission voiced its concerns in the past with "methodologies that place all the emphasis on maximum design day as a way to allocate costs. This method may result in an inappropriate shift of costs to the residential customer class. For this reason, cost-of-service methodologies should give some consideration to volume of use." Administrative Case No. 297, *An Investigation of the Impact of Federal Policy on Natural Gas to Kentucky Consumers and Suppliers* ("Admin. 297") (Ky. PSC May 29, 1987), Order at 47.

The Commission notes that the AG's COSS in this proceeding failed to show the steps of functionalization and classification. When asked in an information request to provide the COSS electronically with all three steps shown separately, the AG provided an electronic copy that shows only the allocation step. When asked during the formal hearing to provide the COSS showing the omitted steps, Mr. Watkins stated that he had not performed the first two steps, and would not be able to provide it unless he was compensated.[101] As was stated in Admin. 297, the Commission prefers that COSS be disaggregated to the greatest extent possible[102] so that the functionalization and classification, as well as allocation, are available for review. Absent an analysis showing all steps of the COSS, the Commission is unable to fully analyze the COSS and therefore is unable to give it the same consideration as a study that includes an analysis of all three steps. With this Order, the Commission puts all parties to future rate proceedings on notice that we cannot give full consideration to a COSS that does not show separately each of the typical individual COSS steps of functionalization, classification, and allocation.

Revenue Allocation

According to Atmos-Ky., while the results of its COSS show that all customer classes except the residential class contribute adequately to its cost of service, it chose to allocate a portion of the requested revenue increase to each customer class.[103] It

[101] January 23, 2014 hearing at 19:32:25.

[102] Admin. 297 (Ky. PSC May 29, 1987), Order at at 42-43.

[103] As stated previously, the revised COSS filed as Exhibit PHR-3 shows both the Residential and Firm Industrial classes providing less than the system average return at present rates.

proposed to increase the customer charges and volumetric rates of all classes with the exception of special contract customers, and to allocate greater increases to volumetric charges as opposed to fixed monthly customer charges.[104] Atmos-Ky.'s proposed allocation of its requested base-rate increase results in maintaining approximately the same percentage of total revenue responsibility among customer classes as exists at current rates.[105]

The AG recommended base-rate revenue increases for all customer classes as well, with lesser increases allocated to firm-sales customers, and with greater increases allocated to firm-transportation, and interruptible-sales and transportation customers. The AG recommended that revenue increases allocated to firm-sales customers be recovered via increases in volumetric rates only, with no increase in monthly customer charges for firm-G-1-sales customers.[106]

The AG also recommended imputing an approximately $3 million increase in base-rate revenues to special-contract customers or to Atmos shareholders.[107] The AG asserted that 50 percent of the tariff rate discounts attributable to 17 special contracts with 16 industrial customers subject to bypass threat should be borne by either those customers or shareholders, with the other 50 percent borne by other customers.[108] The AG stated in his post-hearing brief that it is possible some special contract customers

[104] Martin Testimony at 24.

[105] January 23, 2014 hearing at 11:58:06.

[106] Direct Testimony of Glenn A. Watkins at 44-45.

[107] *Id.* at 45.

[108] AG's post-hearing brief at 11-12.

are legitimate bypass threats, but that "it is likely that some of these contracts are unreasonable and some of the special contract customers are not legitimate threats to bypass Atmos."[109] The AG also recommended that the Commission require Atmos-Ky. to provide an analysis of the reasonableness of the special contracts and whether they represent legitimate bypass threats. A similar analysis was a provision in the settlement agreement between the AG and Columbia Gas of Kentucky, Inc. ("Columbia") in Case No. 2013-00167[110] after the AG raised the same concern regarding the continued reasonableness of special contracts in that case. In the Commission's final Order approving the settlement agreement, we ordered Columbia to submit the results of its analyses on the threat of bypass by its special contract customers as part of its next application for an adjustment of its base rates.

Responding to the AG's proposal to impute $3 million of special-contract revenue discounts to special-contract customers or Atmos shareholders, Atmos-Ky. asserted in its post-hearing brief that all its special contracts were filed with the Commission; were supported by financial analysis demonstrating that they generated revenue sufficient to cover all variable costs and make a contribution to fixed costs; were reviewed, accepted and stamped by the Commission; and that the revenues generated were included in each subsequent rate case before the Commission. Atmos-Ky. claimed that physical bypass of its system remains a viable option for each special-contract customer, and

[109] *Id.* at 12.

[110] Case No. 2013-00167, *Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates for Gas Service* (Ky. PSC Dec. 13, 2013).

that it would be unwarranted and unjust to disallow the revenue discounts from its previously approved contracts.[111]

The Commission agrees with both Atmos-Ky. and the AG that increases should be allocated to all sales and transportation rate classes. We do not agree, however, that it is reasonable to impute a rate increase to special-contract customers. With regard to the AG's proposal to impute $3 million in revenue responsibility to special-contract customers, or to Atmos shareholders if Atmos-Ky. is not able to raise the rates of those customers, the Commission finds that there is no basis in the record of this proceeding to do so. Atmos-Ky. established to the Commission's satisfaction at the time of filing the special contracts that they generated revenue sufficient to cover the variable costs related to serving each customer and make contributions to fixed costs. However, the Commission also finds reasonable the AG's recommendation to require Atmos-Ky. to file analyses similar to that required of Columbia in its next base-rate application. The Commission will therefore require Atmos-Ky. to internally conduct and maintain studies, analyses, reports, quantifications, etc., that demonstrate the threat of bypass by each of its special-contract customers, and that the special contracts continue to generate sufficient revenue to cover variable costs and contribute to fixed costs. This information is to be provided in Atmos-Ky.'s next base-rate case application.

The Commission's revenue allocation as reflected in the rates found reasonable herein generally preserves the existing base-rate revenue responsibility among the classes, excluding gas cost.

---

[111] Atmos-Ky.'s post-hearing brief at 47-48.

Rate Design

Atmos-Ky. proposed no change in rate design, maintaining its current monthly base customer charge and declining block volumetric rates for all rate schedules. It proposed to increase the G-1 Firm Sales Service base customer charge to $16.00 for residential customers and to $40.00 for non-residential customers. It also proposed to increase the base customer charge for G-2 Interruptible Sales Service and for T-4 and T-3 Firm and Interruptible Transportation Service customers to $350.00, which is supported by its COSS. Atmos-Ky. proposed to increase volumetric rates for all customer classes, with a greater relative increase allocated to the first block (0 – 300 Mcf) for G-1 firm sales customers and T-4 firm transportation customers.

As mentioned in the discussion on revenue allocation, the AG recommends that Atmos-Ky.'s residential base monthly customer charge not be increased above $14.28, the residential base customer charge, including the Pipe Replacement Program ("PRP") surcharge, in effect when Atmos-Ky. filed its application. The AG stated that any increase awarded to Atmos-Ky. should be allocated to the volumetric delivery charge to give customers the opportunity to lower their bills through conservation.[112] The Commission notes that, based on the $2.61 monthly residential PRP rate we approved effective October 1, 2013 in Case No. 2013-00304,[113] Atmos-Ky.'s residential customers are now paying $15.11 through the combination of the current $12.50 base customer charge and PRP surcharge.

---

[112] AG's Post-Hearing Brief at 26.

[113] Case No. 2013-00304, *Application of Atmos Energy Corporation to Establish PRP Rider Rates for the 12-Month Period Beginning October 1, 2013* (Ky. PSC Sept. 17, 2013).

The Commission finds Atmos-Ky.'s proposed monthly base customer charges, including the $16.00 residential base customer charge, to be reasonable based on its COSS and the relatively minor increases from the level of monthly customer charges currently paid by all customer classes. Atmos-Ky.'s proposed rate design and customer charges for all customer classes should be approved, and the remainder of the revenue increase awarded herein should be recovered through higher volumetric rates. The volumetric rates approved herein are either identical to or approximate the volumetric rates proposed by Atmos-Ky. for the second and third rate blocks for G-1 firm sales and T-4 firm transportation rate classes; and for both blocks of G-2 interruptible sales and T-3 interruptible transportation customers. The remainder of the increase is recovered through the 0 – 300 Mcf block of firm sales and transportation customers, maintaining more closely the existing relationship between the first rate block and the second and third rate blocks than had been proposed by Atmos-Ky.

Weather Normalization Adjustment

Atmos-Ky. proposed that its Weather Normalization Adjustment ("WNA") be granted permanent approval. Atmos-Ky. points out that Columbia, Delta, and Louisville Gas and Electric Company have all received permanent approval from the Commission of their WNA mechanisms. Atmos-Ky.'s proposed WNA tariff defines normal billing cycle HDD as being based on NOAA's 30-year normal for the period of 1981-2010. In Atmos-Ky.'s post-hearing brief, it alluded to testimony that it is willing to use a different data set for calculating its WNA, but stated its concern that the same data set should be used for normalizing test-year revenues in its rate case as is used for its WNA.

The Commission finds that Atmos-Ky.'s proposal for permanent approval of its WNA is reasonable and should be granted. Atmos-Ky.'s WNA tariff should likewise be approved including the language concerning NOAA's 30-year normal for the period ending 2010. In Atmos-Ky.'s future rate proceedings, this WNA tariff language setting out the time period used should be updated to reflect the time period approved by the Commission to weather normalize revenues in those rate proceedings.

Margin Loss Rider and System Development Rider

Atmos-Ky. proposed to implement two new tariffs, a Margin Loss Rider ("MLR") and a System Development Rider ("SDR"), which it believes will help delay the time and cost associated with a general rate case.[114] Atmos-Ky. proposes the MLR to recover 50 percent of margins lost due to the Economic Development Rider ("EDR"), its Alternative Fuel Flex Provision, or negotiated rates with pipeline bypass candidates. It proposed the lost margin as half the difference between existing tariff rates and the negotiated special contract rates collected over estimated sales volumes of rate schedules G-1 and G-2 (firm and interruptible sales service rate schedules). The proposed MLR tariff contains a Balancing Adjustment provision to reconcile the difference between billed revenues and revenues that would have been billed absent the rider, plus interest at the average the 3-month Commercial Paper Rate for the immediately preceding 12-month period. In support of its proposal, Atmos-Ky. stated that the Commission approved an MLR tariff in a general rate proceeding of Atmos-Ky.'s predecessor company, Western,

[114] Martin Testimony at 30.

in Case No. 1999-070.[115] That tariff resulted from a unanimous settlement agreement and provided for lost revenues to be shared equally by ratepayers and shareholders.

The SDR is proposed to recover investment related to economic development initiatives for overall system or reliability improvement that cannot be directly assigned to a customer or group of customers. Atmos-Ky. states that the SDR is intended to encourage industrial development, infrastructure investment and job growth within its service area. Atmos-Ky.'s proposed tariff describes the SDR revenue requirement as consisting of the following:

1. SDR-related Plant In-Service not included in base gas rates minus the associated SDR-related accumulated depreciation and accumulated deferred income taxes;

2. Retirement and removal of plant related to SDR construction;

3. The rate of return on the net rate base being the overall rate of return on capital authorized for the Company's Pipe Replacement Program Rider;

4. Depreciation expense on the SDR related Plant In-Service less retirements and removals; and

5. Adjustment for ad valorem taxes.

Atmos-Ky. proposed that the SDR rate be charged to the G-1 and G-2 rate classes in proportion to their relative base revenue shares approved in its most recent rate case.

[115] Case No. 1999-070, *The Application of Western Kentucky Gas Company for an Adjustment of Rates* (Ky. PSC Dec. 21, 1999).

The Commission, in Administrative Case No. 327 ("Admin. 327"),[116] specifically stated that utilities with active EDR contracts should demonstrate through detailed cost-of-service analysis that nonparticipating ratepayers are not adversely affected by EDR customers, and that cost-recovery issues are to be held for general rate proceedings. Atmos-Ky. proposed these same riders in Case No. 2012-00066,[117] in which it stated that EDR promotes an important public purpose similar to pipe-replacement programs and, therefore, it should be permitted to recover its costs on a more current basis.[118] The Commission approved Atmos-Ky.'s EDR in Case No. 2012-00066, but did not approve the MLR and SDR riders. Atmos-Ky. states in its application in the instant proceeding that all customers will share in the benefits of increased industrial development and job creation and as a result should not be considered adversely affected by the proposed MLR and SDR riders. In spite of this claim, Atmos-Ky. stated in response to Item 177 of the AG's First Request for Information and in response to Item 27 of Staff's Third Request that transportation customers would not be expected to benefit as much from development, infrastructure investment, and job growth as G-1 and G-2 sales customers, which are the only customer classes proposed to be subject to the riders.

---

[116] Administrative Case No. 327, *An Investigation into the Implementation of Economic Development Rates by Electric and Gas Utilities* (Ky. PSC Sept. 24, 1990).

[117] Case No. 2012-00066, *Application of Atmos Energy Corporation for an Order Approving Economic Development Riders* (Ky. PSC Aug. 27, 2012).

[118] The Commission acknowledged in the final Order in Case No. 2012-00066 that EDRs promote a public purpose, but stated that it was not persuaded that the purpose is similar to the issue of public safety that is promoted by the pipe replacement programs of Atmos and other gas utilities.

The AG recommended that the MLR not be approved, citing the fact that the MLR was previously approved in a black box settlement and not as a result of a litigated proceeding.[119] The AG stated in his post-hearing brief that Atmos-Ky. should not be awarded an MLR that would encourage future special contracts, which he is concerned would not be responsibly administered. If the Commission approves an MLR for Atmos-Ky., the AG recommends that we impose conditions and exercise ongoing supervision over such a mechanism.[120] The AG had no recommendation with regard to the SDR.

The Commission finds that the record in this proceeding does not support Atmos-Ky.'s need for an MLR or an SDR. In response to hearing requests for information concerning the MLR, Atmos-Ky. stated that, since 2009, it had revenue losses of only $3,543 due to fuel switching through its Alternative Fuel Flex Provision, no revenue losses from new special contracts, and that it has entered into no EDR contracts.[121] The Commission notes that if Atmos-Ky. were to enter into a special contract with an EDR customer, in most instances it should be to add incremental load and that revenue collected from that customer would be in addition to base-rate revenues approved in this rate case. Because Atmos-Ky.'s experience over the last five years does not support the likelihood of revenue losses that would indicate the need for such a revenue-stabilizing mechanism, the Commission finds that the addition of the proposed MLR to Atmos-Ky.'s tariffs is not warranted or reasonable.

---

[119] AG's post-hearing brief at 13.

[120] *Id.* at 14.

[121] Atmos-Ky.'s Responses to Hearing Discovery Requests, Question 1-03.

Atmos-Ky.'s response to Item 5 of Staff's Third Request indicates no revenue loss in the last five years resulting from projects that would have qualified for recovery through the SDR if such a tariff rider had been in use during that time, and that no such projects are contemplated during the period 2014 through 2019. While we support economic development efforts that benefit jurisdictional utilities, their customers, their shareholders, and their service areas as evidenced by the findings in Admin. 327, the Commission finds that the SDR is not warranted or reasonable based on the record of this proceeding. The Commission further finds that its denial of the SDR should be without prejudice for Atmos-Ky. to request the SDR in the future if it experiences increasing opportunities for projects that would be subject to such a mechanism.

General Firm Sales (G-1) & Interruptible Sales (G-2) Natural Gas Vehicle Provisions

Atmos-Ky. proposed to add the same language to its G-1 and G-2 sales tariffs that is contained in its T-3 and T-4 Transportation Service tariffs to accommodate sales customers that would like to offer natural gas as a motor vehicle fuel. The additional language will permit sale of gas delivered to a customer for resale only if the gas is used as a motor vehicle fuel. Atmos-Ky.'s revision to its G-1 and G-2 sales tariffs to permit the sale of natural gas for resale as a motor vehicle fuel is reasonable, is in keeping with its transportation tariffs, and should be approved.

$10 Door Tag Fee

Atmos-Ky. proposed to implement a $10 Door Tag Fee to be charged after a customer's account becomes delinquent and it hangs a door tag at the customer's premises. Atmos-Ky. states that, at times, an employee will drive to the customer's premises and leave a door tag notifying the customer that gas service will be disconnected if the bill is not paid.[122] The purpose of the fee, according to Atmos-Ky., is to benefit customers by preventing disconnection and potentially eliminating more costly reconnection charges. This fee would be in addition to a $39 reconnect fee a customer is required to pay to re-establish service if the customer is disconnected for non-payment.[123] Atmos-Ky. did not provide any cost justification for the fee, but claimed the fee was nominal and would only help to offset the cost of the employee trip.

In response to a Commission Staff request for information, Atmos stated that it "does not plan on using [the door tags] often, but wanted to reinstitute the option since it was a past practice."[124] During testimony provided at the public hearing, however, Atmos-Ky. noted that it intended that the Door Tag Fee be implemented on a pilot basis, that its use will be discontinued if it proves to be unsuccessful,[125] and that the fee would be applied to all customers who received a disconnect notice.[126]

The AG took no position on the proposed fee.

Due to the lack of cost support and somewhat inconsistent information provided, the Commission will deny Atmos-Ky.'s request to implement the $10 door tag fee. The Commission is concerned by the fact that, while a customer could benefit by avoiding a more costly $39 reconnect fee, a customer not heeding the door tag would be required to pay $10 in addition to all other fees. Should Atmos-Ky. wish to propose a door tag

---

[122] Martin Testimony at 31-32.

[123] January 23, 2014 hearing at 11:51:45.

[124] Response to Staff's Second Request, Item 27.

[125] January 23, 2014 hearing at 11:52:55.

[126] *Id.* at 11:53:35.

fee in a future application, it should file more supporting details for the fee, including but not limited to the fee's success as a deterrent to non-payment and disconnection in other jurisdictions; cost support justifying the proposed charge; an estimate of revenue to be collected by the fee; and the details of the proposed pilot program if it is to be implemented as a pilot.

Other Tariff Changes

Atmos-Ky. proposed changes to its tariffs to reflect revisions to the Commission's regulations. Through the process of discovery, Atmos-Ky. agreed to further revise its tariffs, and provided amended tariff sheets incorporating all revisions. Atmos-Ky.'s tariff revisions as proposed and as further developed through the process of discovery are reasonable and should be approved.

Gas Transportation Thresholds

In 2010, the Kentucky General Assembly adopted Joint Resolution 141, which directed the Commission to commence a collaborative study of natural gas retail competition programs and to prepare and submit a report to the Kentucky General Assembly and the Legislative Research Commission. Pursuant to that directive, the Commission established Case No. 2010-00146 to conduct an investigation of natural gas competition.[127] After developing a record that consisted of discovery responses, testimony, and public comments, and conducting a public hearing, the Commission concluded that the existing transportation thresholds of jurisdictional local distribution

[127] Case No. 2010-00146, *An Investigation if Natural Gas Competition Programs* (Ky. PSC Dec. 28, 2010).

companies ("LDCs") should be further examined, and that each LDC's tariffs and rate design would be evaluated in its next general rate proceeding.

In its rate application in this proceeding, Atmos-Ky. discusses its transportation and pooling services and its 9,000 Mcf per year volumetric eligibility threshold. It stated its belief that its existing eligibility threshold is set at an appropriate level and proposed no changes to its transportation service. The issue of Atmos-Ky.'s transportation service and eligibility threshold was further developed through the process of discovery by Staff, and was addressed by Stand's March 13, 2014 Brief and by Atmos-Ky.'s March 21, 2014 Reply Brief. Atmos-Ky. established through testimony and responses to discovery that it has approximately 30 customers that qualify for transportation service but choose to stay on sales service;[128] that over the last five years it has received only four requests for transportation service from non-residential customers whose volumetric usage would make them ineligible for transportation service;[129] that up-front costs such as electronic flow metering, monthly administration fees and potential cash out obligations would make it difficult for lower-volume-usage customers to achieve savings;[130] and that its existing transportation service threshold is not an outlier compared to other Kentucky jurisdictional LDCs.[131]

Stand recommends that Atmos-Ky.'s volumetric transportation threshold be lowered to allow more customers to purchase natural gas in the market. Stand states

---

[128] Martin Testimony at 33-34.

[129] Response to Staff's Second Request, Item 11.

[130] Martin Testimony at 33.

[131] Response to Staff's Third Request, Item 6.

that the Commission should require Atmos-Ky. to lower the threshold from 9,000 to 3,000 Mcf per year if Atmos-Ky. will not do so voluntarily.[132] According to Stand, its suggestion is based on general industry knowledge, the thresholds of other LDCs, and the record in this case and that of Case No. 2010-00146.[133] Stand states that utilities in Kentucky and other states have proven that any risks and dangers of gas transportation are resolved by properly drafted tariffs which are not unduly punitive, do not unduly benefit the utility, and which serve to control supplier behavior.[134] Stand also advises that if the transportation threshold is lowered, the Commission must guard against the risk that other provisions of Atmos-Ky.'s tariff would be made more punitive and restrictive.[135] Stand cites the following as reasons that Atmos-Ky. should be indifferent to whether it or another supplier is supplying gas to its customers: (1) Atmos-Ky. is not allowed to profit from providing sales gas; and (2) Atmos-Ky. charges fees to transportation customers to address system balancing issues. Stand states that these factors justify lowering the threshold to transport. Stand also contends that it is unclear why Atmos-Ky. or the Commission has not lowered the volumetric threshold to transport.[136] Stand referred to the record in 2010-00146 as containing evidence that every customer for whom it had provided information in response to Staff data requests

---

[132] Stand's Brief at 6.

[133] *Id.*

[134] *Id. at* 7.

[135] *Id. at* 8.

[136] *Id.*

had saved money compared with what it would have been charged by its LDC.[137] It suggests that the fact that the 30 customers who qualify for transportation service choose to stay on sales service indicates a lack of information available to Atmos-Ky. customers regarding transportation tariff options and the relative costs and benefits of sales versus transportation service.[138]

In response to Stand's argument regarding the issue of the volumetric eligibility threshold for transportation service, Atmos-Ky. states that Stand provided no evidence supporting its recommendation to reduce the threshold from 9,000 to 3,000 Mcf per year, and that it provided only broad generalization concerning the issue.[139] Atmos-Ky. argues, in response to Stand's uncertainty as to why the Commission has not lowered its volumetric threshold for transportation service, that the reason is the lack of demand from customers for a lower threshold and that the Commission has no basis to arbitrarily impose a reduction. Atmos-Ky. submits that it is a lack of interest and economic benefit that causes sales customers otherwise eligible for transportation service to remain sales customers, and not a lack of information, as Stand claims.[140] Atmos-Ky. states the Commission should not accept Stand's apparent assumption that customers are incapable of obtaining information and making informed judgments.[141]

---

[137] *Id.* at 9.

[138] *Id.* at 11.

[139] Atmos-Ky.'s reply brief at 4.

[140] *Id.*

[141] *Id.*

The information in the record in this case reflects a meaningful effort to address the Commission's directive in Case No. 2010-00146 that gas transportation thresholds be examined in each LDC's next rate case. We find that the exploration of Atmos-Ky.'s gas transportation services and issues surrounding the availability of such service to more customers satisfies the intent of our Order in that case. There is nothing in the record of this proceeding to indicate that sales customers are disadvantaged by Atmos-Ky.'s decision to maintain its existing 9,000 Mcf per year transportation threshold. In the almost 10 months that this rate case has been before the Commission, no customer filed comments in opposition to Atmos-Ky's existing 9,000 Mcf per year transportation threshold and no customer requested to intervene to challenge that threshold level. Atmos-Ky.'s volumetric threshold is not the lowest among Kentucky LDCs, nor is it the highest. The Commission will continue to monitor the issue of transportation thresholds in future base-rate proceedings, and Atmos-Ky. should anticipate further inquiry regarding sales customers' expressions of interest in transportation service.

OTHER ISSUES

Stand's Allegations

Stand alleged in its post-hearing brief that it has been denied due process in this matter on two grounds: 1) the Commission did not have the authority to limit the scope of Stand's intervention to the issue of Atmos-Ky.'s threshold for transportation service; and 2) Stand was denied the right to participate in discovery due to the timing of our Order granting intervention. We will address each of these allegations separately.

The Commission finds that the only person with a statutory right to intervene is the AG, pursuant to KRS 367.150(8)(b). Intervention by all others is permissive and is within the sound discretion of the Commission. In the unreported case of EnviroPower, LLC v. Public Service Commission of Kentucky, No. 2005-CA-001792-MR, 2007 WL 289328 (Ky. App. Feb. 2, 2007), the Court of Appeals ruled that this Commission retains power in its discretion to grant or deny a motion for intervention, but that discretion is not unlimited. The Court enumerated the statutory and regulatory limits on Commission discretion in ruling on motions to intervene. The statutory limitation, KRS 278.040(2), requires that the person seeking intervention have an interest in the rates or service of a utility, as those are the only two subjects under the jurisdiction of the Commission.

The issues presented in EnviroPower are analogous to the instant case with regard to Commission discretion in granting intervention.[142] Similar to EnviroPower's interest as a competitor in East Kentucky Power Company's ("EKPC") construction of a coal-fired generating plant, Stand's interest as a private natural gas marketer arguably places it in direct competition with Atmos-Ky. in its role as provider of the natural gas commodity to its sales customers. EnviroPower was neither a ratepayer of EKPC nor did it represent a ratepayer of EKPC. Stand is likewise not a ratepayer of Atmos-Ky. nor does it represent a ratepayer in this proceeding.

---

[142] In *EnviroPower*, East Kentucky Power Cooperative Inc. ("EKPC") applied for a Certificate of Public Convenience and Necessity ("CPCN") to self-construct a 278-MW coal-fired generating plant at its Spurlock Station site in Maysville, Kentucky. Before making its application for a CPCN, EKPC had issued a "Request for Proposals" for various contractors to bid on supplying the necessary power. EnviroPower was one of 39 unsuccessful bidders. The Commission denied EnviroPower's request to intervene upon finding that it was not a ratepayer of EKPC, but a rejected bidder whose interests were not identical to ratepayers'; and that EnviroPower had a legal duty to its members to maximize profits; a far different goal from the protection of ratepayers. Although intervention was denied, EnviroPower was added to the service list so that it could monitor the proceedings, submit further information and comment upon the issues and in fact it filed extensive comments in the form of prepared testimony.

It is only because of an assurance made by the Commission in Case No. 2010-00146, An Investigation of Natural Gas Retail Competition Programs,[143] that Stand was granted intervenor status in this matter. The Commission, in its final report to the Kentucky General Assembly in Case No. 2010-00146, states, "The Commission believes that existing transportation thresholds bear further examination, and the Commission will evaluate each LDC's tariffs and rate design in each LDC's next general rate proceeding."[144] As this is Atmos-Ky.'s first general rate proceeding following the Commission's report, and consistent with the report, Stand was granted intervention in the current matter but its intervention was limited "to participation on the issues of Atmos Energy's transportation threshold levels and any other matters related thereto, but not to whether a Pilot Program for Schools or enhanced Standards of Conduct should be added." The Commission disagrees with Stand's argument that it should have been allowed to explore these other topics in the present case. We find both topics to be extraneous to our consideration of either transportation thresholds, as we agreed to consider in our final report in Case No. 2010-00146, or to our consideration of Atmos-Ky.'s application for an adjustment of rates in the present case. Stand contends that an amendment to the Commission's administrative regulations, which removed both the words "limited" and "full" pertaining to intervention, arguably grant Stand, as an intervenor in this case, the right to interject any topic it chooses into a proceeding before the Commission, regardless of either its relevance or applicability to the matter at hand.

[143] Case No. 2010-00146, *An Investigation of Natural Gas Retail Competition Programs* (Ky. PSC Dec. 28, 2010).

[144] *Id.* at 23.

We find this position to be erroneous. Neither the Commission's former regulation pertaining to intervention,[145] nor as it was amended in 2013,[146] bestow upon any intervenor the right to introduce tangential issues into Commission proceedings, as Stand has attempted to do in this matter regarding a pilot program for Kentucky's school facilities and regarding its promotion of Commission-imposed Standards of Conduct against Atmos-Ky. Further, the prior provision in our regulations allowing for "limited intervention" had nothing to do with limiting the issues that could be addressed by an intervenor. Rather, the limitation in "limited intervention" extended only to the documents that other parties had to serve on the limited intervenor and the exclusion of the limited intervenor as a designated party for purposes of rehearing or judicial review.

Stand maintains that it was denied due process because the Commission did not rule on its motion to intervene for more than three months and then after the closure of discovery. The Commission finds Stand's position without merit on two separate grounds. First, 807 KAR 5:001, Section 4(11)(d), the amended regulation regarding intervention which Stand earlier touts, states, "Unless the commission finds good cause to order otherwise, a person granted leave to intervene in a case shall, as a condition of his intervention, be subject to the procedural schedule in existence in that case when the order granting the person's intervention is issued." Although Stand would seem to imply otherwise, there is nothing in this provision that conditions its applicability on when intervention is granted by the Commission. In addition, there is nothing in the record to indicate any effort by Stand to seek amendment of the procedural schedule in place at

[145] 807 KAR 5:001, Section 3(8).

[146] 807 KAR 5:001, Section 4(11).

the time it was granted intervention. The initial language, "Unless the commission finds good cause to order otherwise. . ." would allow the Commission to amend the procedural schedule if "good cause" exists, but Stand never made such a request or brought its concern to the Commission while the evidentiary record was open. In fact, Stand never raised the claim of a denial to participate in discovery until it filed its post-hearing brief, which was over six months after it was granted intervention. Thus,its recent claim that it was denied due process is unconvincing.

The Commission also finds Stand's claim that it was denied the opportunity to participate in discovery disingenuous on a second level. At the time Stand was granted intervention on September 3, 2013, the only discovery deadline that had passed was the request for information to Atmos-Ky. due on August 14, 2013, to which Atmos-Ky. responded on August 28, 2013. After the Commission's September 3, 2013 Order granting its intervention, Stand had the opportunity to file supplemental requests for information to Atmos-Ky. by September 11, 2013; to file intervenor testimony by October 9, 2013; and to file requests for information to the AG by October 23, 2013. Stand had each of these opportunities as part of the original procedural schedule, which it accepted as a condition of its intervention,[147] and did not request be amended.

Stand's participation in this case has been minimal. Following the filing of its motion to intervene and memorandum in support of its motion, which primarily advocated that Atmos-Ky. be required to implement a pilot program for Kentucky School

[147] 807 KAR 5:001, Section 4(11)(d).

Facilities[148] and that the Commission impose Standards of Conduct against Kentucky gas utilities with unregulated gas marketing affiliates,[149] both issues that are outside the scope of these proceedings, its participation has consisted of briefly questioning two of Atmos-Ky.'s ten witnesses at the January 23, 2014 hearing, each for less than five minutes,[150] and filing a post-hearing brief.[151]

Stand did not request that the procedural schedule be amended; did not file supplemental requests for information to Atmos-Ky.; did not request information from the other intervenor; did not file testimony on its own behalf or present any witnesses at the January 23, 2014 hearing; did not question eight of Atmos-Ky.'s ten witnesses who testified at the January 23, 2014 hearing; and did not question either of the Attorney General's two witnesses who testified at the January 23, 2014 hearing.

In summary, we find that Stand's choices regarding its level of participation in this case create no substantive or procedural due process violations by the Commission.

<u>Depreciation Study</u>

Atmos-Ky.'s depreciation rate study filed as part of its application[152] is the first depreciation rate study filed by Atmos-Ky. since its 2006 general rate case.[153] Based

---

[148] Memorandum Supporting Motion of Stand Energy Corporation to Intervene at pp.5-6.

[149] *Id.* at 7.

[150] Cross-Examination of Mark Martin at 11:17:35–11:20:00 and Cross-Examination of Gary Smith at 5:59:41–6:04:21, January 23, 2014 hearing.

[151] By Order issued March 7, 2014, the Commission granted Stand's e-mail request for additional time to file a post hearing brief.

[152] Direct Testimony of Dane A. Watson.

[153] Case No. 2006-00464, *Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC July 31, 2007).

on the current study's results, Atmos-Ky. proposed new depreciation rates that would increase its annual depreciation expense by approximately $1.1 million.

The Commission finds that Atmos-Ky.'s proposed depreciation rates are reasonable and should be approved for use by Atmos-Ky. on and after the effective date of the gas service rates approved herein. The Commission also finds that Atmos-Ky. should prepare a new depreciation rate study for Commission review by the earlier of five years from the date of this Order or the filing of Atmos-Ky.'s next application for an adjustment in its base rates.

Wireless Meter Reading

Atmos-Ky.'s application indicated that in fiscal year 2014 it would undertake a Wireless Meter Reading ("WMR") project.[154] It intends to install 20,000 WMR devices in areas where (1) it currently uses contract meter readers, (2) it expects to experience workforce reductions due to retirements and relocations, and (3) meter reading is costly due to the time required for individual reads.[155] While Atmos-Ky. does not expect significant savings in the near term, it indicates that, over time, company meter readers would be trained for other positions that become vacant due to retirements and would fill those positions, resulting in an overall reduction in the required number of operational employees.[156]

Although Atmos-Ky. did not reflect any decrease in expenses during the test year due to the WMR project, but expects to realize savings from the project in the long term.

[154] Direct Testimony of Ernest B. Napier at 13.

[155] *Id.*

[156] *Id.* at 14.

The Commission is interested in the level of savings Atmos-Ky. will realize as a result of the WMR project on a long-term term basis. Accordingly, in conjunction with its next general rate application, we find that Atmos-Ky. should submit an analysis of the costs incurred and savings realized because of the WMR project from its inception to a date within 90 days of the submission of the rate application.

SUMMARY

The Commission, after consideration of the evidence of record and being otherwise sufficiently advised, finds that:

1. The rates set forth in the Appendix to this Order are the fair, just, and reasonable rates for Atmos-Ky. to charge for service rendered on and after January 24, 2014.

2. The rate of return granted herein is fair, just, and reasonable and will provide sufficient revenue for Atmos-Ky. to meet its financial obligations with a reasonable amount remaining for equity growth.

3. The rates proposed by Atmos-Ky. would produce revenue in excess of that found reasonable herein and should be denied.

4. Atmos-Ky.'s proposal to implement new depreciation rates based on the depreciation study it filed in this proceeding should be granted with the new depreciation rates to be effective as of the effective date of the gas service rates approved herein.

5. Atmos-Ky. should file a new depreciation study for Commission review by the earlier of five years from the date of this Order or the filing of its next general rate application.

6. The proposed MLR and SDR tariffs are not currently warranted and should be denied.

7. The proposed Door Tag Fee is not reasonable and should be denied.

8. Atmos-Ky.'s request for permanent approval of its WNA tariff and the proposed language concerning NOAA's 30-year normal for the period ending 2010, which should be updated with each base-rate proceeding, is reasonable and should be approved.

9. Atmos-Ky.'s proposal to revise its G-1 and G-2 sales tariffs to permit the resale of natural gas as a motor vehicle fuel is reasonable and should be approved

10. All other tariff modifications proposed by Atmos-Ky. or agreed to by Atmos-Ky. through the discovery process in this proceeding are reasonable and should be approved.

11. As part of its next application for an adjustment of its base rates for gas service, Atmos-Ky. should submit the IRS private-letter ruling required herein, and should defer the related cost in a regulatory asset account to be addressed in that rate proceeding.

12. As part of its next application for an adjustment of its base rates for gas service, Atmos-Ky. should submit the comparison required herein of weather-normalization methodologies along with support for the time period it proposes to use to normalize revenues, including the superiority of the chosen method in terms of its predictive value for future temperatures.

13. As part of its next application for an adjustment of its base rates for gas service, Atmos-Ky. should submit the results of its analyses required herein on the

threat of bypass posed by its special contract customers and on the sufficiency of the revenue generated by these customers to continue to cover variable cost and make a contribution to fixed cost.

14. As part of its next application for an adjustment of its base rates for gas service, Atmos-Ky. should submit an analysis of the costs incurred and savings realized due to the WMR project from its inception to a date within 90 days of the submission of the rate application.

15. As part of its next application for an adjustment of its base rates for gas service, Atmos-Ky. should submit multiple-methodology COSSes in order to give the Commission a range of reasonable results for use in determining rate design.

16. Future COSSes filed by any party should show separately each of the typical individual COSS steps of functionalization, classification, and allocation.

17. The record in this proceeding regarding Atmos-Ky.'s gas transportation services and issues surrounding the availability of such service satisfies the intent of our Order in Case No. 2010-00146.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by Atmos-Ky. are denied.

2. The rates in the appendix to this Order are approved for service rendered by Atmos-Ky. on and after January 24, 2014.

3. The depreciation rates proposed by Atmos-Ky. are approved.

4. Atmos-Ky. shall submit a new depreciation study for Commission review by the earlier of five years from the date of this Order or the filing of its next general rate case.

5. Within 20 days of the date of this Order, Atmos-Ky. shall file with the Commission, using the Commission's Electronic Tariff Filing System, new tariff sheets setting forth the rates, charges, and revisions approved herein and reflecting their effective date and that they were authorized by this Order.

6. Within 60 days from the date of this Order, Atmos-Ky. shall refund with interest all amounts collected for service rendered from January 24, 2014, through the date of this Order that are in excess of the rates set out in the appendix to this Order. The amount refunded to each customer shall equal the amount paid by each customer during the refund period in excess of the rates approved herein.

7. Atmos-Ky. shall pay interest on the refunded amounts at the average of the 3-Month Commercial Paper Rate as reported in the Federal Reserve Bulletin and the Federal Reserve Statistical Release on the date of this Order.

8. Within 75 days from the date of this Order, Atmos-Ky. shall submit a written report to the Commission in which it describes its efforts to refund all monies collected in excess of the rates that are set forth in the appendix to this Order.

9. Any documents filed pursuant to ordering paragraph 8 of this Order shall reference the number of this case and shall be retained in the utility's post case reference file.

10. Atmos-Ky.'s next application for an increase in its base rates shall contain the information required in finding paragraphs 11 through 14.

By the Commission

ENTERED

APR 22 2014

KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Executive Director

Case No. 2013-00148

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2013-00148 DATED APR 2 2 2014

The following rates and charges are prescribed for the customers served by Atmos Energy Corporation. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

RATE G-1
GENERAL FIRM SALES SERVICE

Base Charge

$16.00	per meter per month for residential service
$40.00	per meter per month for non-residential service

Distribution Charge

First	300	Mcf	$ 1.3180 per Mcf
Next	14,700	Mcf	$ .8800 per Mcf
Over	15,000	Mcf	$ .6200 per Mcf

RATE G-2
INTERRUPTIBLE SALES SERVICE

Base Charge

$350.00 per delivery point per month

Distribution Charge

First	15,000	Mcf	$ .7900 per Mcf
Over	15,000	Mcf	$ .5300 per Mcf

RATE T-3
INTERRUPTIBLE TRANSPORTATION SERVICE

Base Charge

$350.00 per delivery point per month

Distribution Charge for Interruptible Service

First	15,000 Mcf	$	.7900 per Mcf
Over	15,000 Mcf	$	.5300 per Mcf

RATE T-4
FIRM TRANSPORTATON SERVICE

Base Charge

$350.00 per delivery point per month

Distribution Charge for Firm Service

First	300 Mcf	$	1.3180 per Mcf
Next	14,700 Mcf	$	.8800 per Mcf
Over	15,000 Mcf	$	.6200 per Mcf

Honorable John M Dosker
General Counsel
Stand Energy Corporation
1077 Celestial Street
Building 3, Suite 110
Cincinnati, OHIO 45202-1629

Douglas Walther
5430 LBJ Freeway
1800 Three Lincoln Centre
Dallas, TEXAS 75240

Gregory T Dutton
Assistant Attorney General
Office of the Attorney General Utility & Rate
1024 Capital Center Drive
Suite 200
Frankfort, KENTUCKY 40601-8204

Eric Wilen
Project Manager-Rates & Regulatory Affairs
Atmos Energy Corporation
5420 LBJ Freeway, Suite 1629
Dallas, TEXAS 75420

Jennifer Black Hans
Assistant Attorney General
Office of the Attorney General Utility & Rate
1024 Capital Center Drive
Suite 200
Frankfort, KENTUCKY 40601-8204

Honorable Dennis G Howard II
Assistant Attorney General
Office of the Attorney General Utility & Rate
1024 Capital Center Drive
Suite 200
Frankfort, KENTUCKY 40601-8204

Honorable John N Hughes
Attorney at Law
124 West Todd Street
Frankfort, KENTUCKY 40601

Mark R Hutchinson
Wilson, Hutchinson & Poteat
611 Frederica Street
Owensboro, KENTUCKY 42301

Heather Napier
Office of the Attorney General Utility & Rate
1024 Capital Center Drive
Suite 200
Frankfort, KENTUCKY 40601-8204

BEFORE THE
RAILROAD COMMISSION OF TEXAS

STATEMENT OF INTENT FILED BY ATMOS ENERGY CORP., TO INCREASE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS SERVED BY THE ATMOS ENERGY CORP., MID-TEX DIVISION	§ § § § § §	**GAS UTILITIES DOCKET NO. 10170 AND CONSOLIDATED CASES**

FINAL ORDER

Notice of Open Meeting to consider this Order was duly posted with the Secretary of State within the time period provided by law pursuant to TEX. GOV'T CODE ANN. Chapter 551, *et seq.* (Vernon 2008 & Supp. 2012). The Railroad Commission of Texas adopts the following findings of fact and conclusions of law and orders as follows:

FINDINGS OF FACT

1. Atmos Energy Corp., Mid-Tex Division, (Atmos Energy, Atmos, or company) is a gas utility as that term is defined in the Texas Utility Code and is subject to the jurisdiction of the Railroad Commission of Texas (Commission).

2. On May 31, 2012, Atmos filed a *Statement of Intent* to increase gas utility rates in the unincorporated areas of the Atmos Energy Corp., Mid-Tex Division. The filing was docketed as GUD No. 10170.

3. Atmos proposed that the increased rates become effective on July 5, 2012.

4. On June 26, 2012, the Commission suspended the implementation of Atmos' proposed rates for up to 150 days.

5. Atmos subsequently extended the proposed effective date of the proposed rates, thereby extending the statutory deadline to December 20, 2012.

6. Atmos filed a municipal rate proceeding with 441 cities (Affected Cities) served by Atmos Mid-Tex on January 31, 2012.

7. Atmos Mid-Tex filed the following *Petitions for De Novo Review* of the denial of the *Statement of Intent* by various municipalities that denied that rate request:

   A. GUD No. 10171, Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corp., Mid-Tex Division by the Cities of Abilene, Alba, Albany, et al. on May 31, 2012. These cities include the following: Abilene, Alba, Albany, Allen, Alvarado, Alvord, Angus, Anna, Anson, Arlington, Aubrey, Avery, Azle, Baird, Bangs, Barry, Bartonville, Bedford, Bellevue, Benbrook, Benjamin, Beverly Hills, Blanket, Blum, Bogata, Bonham, Bowie, Brazos Bend, Bridgeport, Bronte, Brownsboro, Brownwood, Bruceville-Eddy, Buckholts, Buffalo Gap, Burleson, Byers, Caddo Mills, Caldwell, Calvert, Cameron, Campbell, Canton, Cashion Community, Celina, Centerville, Childress, Chillicothe, Cisco, Clarksville, Cleburne, Clifton, Clyde, Coleman, Colleyville, Collinsville, Colorado City, Comanche, Commerce, Coolidge, Cooper, Copper Canyon, Copperas Cove, Corral City, Covington, Crawford, Crowley, Dalworthington Gardens, Decatur, DeLeon, Denison, Desoto, Dodd City, Double Oak, Duncanville, Dublin, Ector, Edgecliff Village, Edom, Emhouse, Emory, Ennis, Euless, Everman, Fairfield, Farmers Branch, Farmersville, Ferris, Forest Hill, Fort Worth, Franklin, Frankston, Frisco, Frost, Gainesville, Glen Rose, Glenn Heights, Godley, Goodlow, Gordon, Goree, Gorman, Grandview, Granger, Gunter, Gustine, Haltom City, Hamilton, Harker Heights, Haskell, Hawley, Henrietta, Hewitt, Hico, Highland Village, Holland, Holliday, Honey Grove, Howe, Hubbard, Hurst, Hutchins, Iowa Park, Iredell, Irving, Italy, Itasca, Jewitt, Josephine, Joshua, Justin, Kaufman, Keene, Kemp, Kennedale, Killeen, Knollwood, Ladonia, Lake Worth, Lakeport, Leona, Leonard, Lewisville, Lindsay, Lipan, Little Elm, Little River Academy, Lometa, Lone Oak, Longview, Lorena, Lott, Mabank, Madisonville, Malakoff, Malone, Mansfield, Marble Falls, Maypearl, McGregor, McKinney, Melissa, Meridian, Merkel, Mesquite, Mexia, Midlothian, Miles, Moran, Morgan, Murchison, Murphy, Newcastle, Nocona, Nolanville, Northlake, Novice, Oak Leaf, Oakwood, O'Brien, Oglesby, Olney, Ovilla, Palestine, Palmer, Paradise, Pecan Gap, Pecan Hill, Penelope, Petrolia, Pilot Point, Pleasant Valley, Ponder, Pottsboro, Poynor, Princeton, Putnam, Quanah, Quitman, Ranger, Ravenna, Red Oak, Reno (Lamar County), Retreat, Richland, Richland Hills, River Oaks, Roanaoke, Robert Leek, Rochester, Rockwall, Roscoe, Rosebud, Ross, Rotan, Runaway Bay, Sachse, Saginaw, San Angelo, Sansom Park, Santa Anna, Savoy, Scurry, Seagoville, Sherman, Snyder, Suothmayd, Stamford, Stephenville, Strawn, Streetman, Sweetwater, Talty, Teague, Tehuacana, Thorndale, Thornton, Throckmorton, Tioga, Tom Bean, Trent, Trinidad, Troy, University Park, Valley View, Van Alstyne, Walnut Springs, Westlake, White Settlement, Whitesboro, Wichita Falls, Woodway, Wortham, Wylie, Venus and Yantis.

B. GUD No. 10176, Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corp., Mid-Tex Division by the Cities of Deport, Detroit, and Lakeside on June 8, 2012.

C. GUD No. 10177, Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corp., Mid-Tex Division by the Cities of Addison, Alma, Archer City, et al. on June 13, 2012. These cities include the following: The cities of Addison, Alma, Archer City, Argyle, Aurora, Ballinger, Bandera, Bardwell, Bartlett, Bells, Bertram, Blackwell, Blooming Grove, Blossom, Blue Mound, Blue Ridge, Boyd, Bremond, Bryan, Buffalo, Burkburnett, Burnet, Carbon, Carrollton, Cedar Hill, Cedar Park, Chico, College Station, Como, Coppell, Corinth, Corsicana, Crandall, Cross Roads, Dawson, Denton, Early, Eastland, Eustace, Evant, Fairview, Fate, Flower Mound, Forney, Fredericksburg, Garland, Georgetown, Goldthwaite, Granbury, Grand Prairie, Grapevine, Hamlin, Haslet, Hearne, Heath, Hebron, Hickory Creek, Highland Park, Hillsboro, Hutto, Impact, Keller, Kerrville, Knox City, Kosse, Krum, Kurten, Lacy-Lakeview, Lake Dallas, Lampasas, Lancaster, Lavon, Lawn, Leander, Lincoln Park, Llano, Lorain, Lueders, Manor, Mart, Mclendon-Chisholm, Megargel, Milford, Midway, Mobile City, Moody, Muenster, Newark, Nevada, New Chapel Hill, Normangee, North Richland Hills, Paris, Parker, Pflugerville, Plano, Powell, Prosper, Quinlan, Rhome, Robinson, Roby, Rogers, Round Rock, Rowlett, Roxton, Royse City, Rule, Sadler, Saint Jo, Sanctuary, Sanger, Seymour, Shady Shores, South Mountain, Southlake, Springtown, Sulphur Springs, Taylor, Temple, Terrell, The Colony, Thrall, Toco, Trenton, Trophy Club, Tye, Tyler, Valley Mills, Vernon, Waco, Watauga, Waxahachie, Weinert, West, Westworth Village, Whitehouse, Whitewright, Whitney, Wilmer, Windom, Winters, and Wolfe City.

D. GUD No. 10184, Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corporation, West Texas Division by the Cities of Big Spring, Earth, Edmonson, et al. on July 5, 2012. These cities include the following: Abbott, Annona, Athens, Austin, Balch Springs, Bellmead, Belton, Celeste, Chandler, Cockrell Hill, Coyote Flats, Cumby, Electra Garrett, Gatesville, Greenville, Groesbeck, Kerens, Lexington, Marlin, Millsap, Munday, Pantego, Point, Reno (Parker County), Post Oak Bend, Rice, Richardson, Riesel, Rio Vista, Rockdale, San Saba, Somerville, Star Harbor, Sun Valley, Sunnyvale, Tuscola, Westover Hills, and Wixon Valley.

8. On March 13, 2012, Atmos filed an *Application of Atmos Energy Corp. to Revise Certain Depreciation Rates* and it was docketed as GUD No. 10147.

9. On June 19, 2012, Atmos filed a *Motion to Consolidate* [depreciation issues for Atmos Mid-Tex from GUD No. 10147] *and Motion to Dismiss as to Atmos Pipeline-Texas.*

10. On June 22, 2012, the depreciation issues for Atmos' Mid-Tex Division from GUD No. 10147 were severed into GUD No. 10179.

11. On June 22, 2012, GUD No. 10179 was consolidated into GUD No. 10170.

12. On June 14, 2012, Staff of the Railroad Commission of Texas (Staff) and the State of Texas Agencies and Institutions of Higher Education (State Agencies) intervened in this proceeding.

13. On June 14, 2012, Atmos Texas Municipalities (ATM) intervened in this proceeding on behalf of the following cities: Austin, Balch Springs, Bandera, Barlett, Belton, Blooming

Grove, Bryan, Cameron, Cedar Park, Celeste, Clifton, Commerce, Copperas Cove, Corsicana, Denton, Electra, Fredericksburg, Garrett, Gatesville, Georgetown, Goldthwaite, Granbury, Greenville, Groesbeck, Hamilton, Henrietta, Hickory Creek, Hico, Hillsboro, Hutto, Kerens, Lampasas, Leander, Lometa, Longview, Mart, Mexia, Olney, Pantego, Pflugerville, Ranger, Reno (Parker County), Rice, Richardson, Riesel, Round Rock, San Angelo, Sanger, Somerville, Star Harbor, Trinidad, Trophy Club, and Whitney.

14. On June 22, 2012, Atmos Cities Steering Committee (ACSC) intervened in this proceeding on behalf of the following cities: Abilene, Addison, Allen, Alvarado, Angus, Anna, Argyle, Arlington, Bedford, Bellevue, Benbrook, Beverly Hills, Blossom, Blue Ridge, Bowie, Bridgeport, Brownwood, Burkburnett, Burleson, Caddo Mills, Carrollton, Cedar Hill, Celina, Cisco, Cleburne, Clyde, College Station, Colleyville, Colorado City, Comanche, Coolidge, Coppell, Corinth, Corral City, Crandall, Crowley, Dalworthington Gardens, Denison, DeSoto, Duncanville, Eastland, Edgecliff Village, Emory, Ennis, Euless, Everman, Fairview, Farmers Branch, Farmersville, Fate, Flower Mound, Forest Hill, Fort Worth, Frisco, Frost, Gainsville, Garland, Grand Prairie, Grapevine, Gunter, Haltom City, Harker Heights, Haskell, Haslett, Hewitt, Highland Park, Highland Village, Honey Grove, Hurst, Iowa Park, Irving, Justin, Kaufman, Keene, Keller, Kemp, Kennedale, Kerrville, Killeen, Krum, Lakeside, Lake Worth, Lancaster, Lewisville, Lincoln Park, Little Elm, Lorena, Madisonville, Malakoff, Mansfield, McKinney, Melissa, Mesquite, Midlothian, Murphy, Newark, Nocona, North Richland Hills, Northlake, Oak Leaf, Ovilla, Palestine, Paris, Parker, Pecan Hill, Plano, Ponder, Pottsboro, Prosper, Quitman, Red Oak, Richland, Richland Hills, River Oaks, Roanoke, Robinson, Rockwall, Roscoe, Rowlett, Royse City, Sachse, Saginaw, Seagoville, Sherman, Snyder, Southlake, Springtown, Stamford, Stephenville, Sulphur Springs, Sweetwater, Temple, Terrell, The Colony, Trophy Club, Tyler, University Park, Venus, Waco, Watauga, Waxahachie, Westlake, Whitesboro, White Settlement, Wichita Falls, Woodway, and Wylie.

15. On July 27, 2012, The City of Dallas intervened in this proceeding and on July 31, 2012, CoServ Gas, Ltd., intervened in this docket.

Notice

16. Atmos Mid-Tex published notice of the proposed rate changes once a week for four or more consecutive weeks, beginning the week of February 6, 2012 and running through the week of March 5, 2012, in newspapers of general circulation in each city affected by the proposed increase.

17. Notice of the filing in this proceeding was accomplished for unincorporated area residential and commercial customers by bill insert beginning on July 20, 2012 and ending on August 20, 2012.

18. Notice to industrial and other non-residential and non-commercial customers was accomplished by mailing the notice to the billing addresses of each directly affected unincorporated customer on July 24, 2012.

19. The publication of notice meets the statutory and rule requirements of notice and provides sufficient information to ratepayers about the statement of intent.

Atmos Energy Corporation Mid-Tex Division

20. Atmos Energy delivers natural gas to approximately 3.2 million residential, commercial, industrial, and public authority customers in twelve states.

21. Atmos Energy has the following six unincorporated gas utility operating divisions located in the respective cities: Dallas, Texas (Mid-Tex Division); Denver, Colorado (Colorado/Kansas Division); Baton Rouge, Louisiana (Louisiana Division); Jackson, Mississippi (Mississippi Division); Lubbock, Texas (West Texas Division); and Franklin, Tennessee and Owensboro, Kentucky (Kentucky/Mid-States Division).

22. Atmos Energy has an operating division, Atmos Pipeline – Texas, which consists of a regulated intrastate pipeline that operates only within Texas.

23. Each of Atmos Energy's utility divisions has its own divisional office that is responsible for the day-to-day operations that are unique to that division.

24. The company's corporate office is located in Dallas, Texas, and provides services such as accounting, legal, human resources, rates administration, procurement, gas supply, information technology, and customer care.

25. Several functions that are shared among the divisions are handled by the company's Shared Services Unit (SSU).

26. These centralized services, or Shared Services, include customer support call centers and are located in Amarillo and Waco, Texas, which are shared by the company's distribution operating divisions.

27. The utility operations in the Mid-Tex Division operates in over 440 cities, towns, and unincorporated areas.

28. The Mid-Tex Division has approximately 350 employees and serves approximately 1.5 million customers in 442 incorporated and unincorporated areas in north and central Texas.

Test Year

29. The test year in this case was the 12-month period ending September 30, 2011.

Books and Records

30. Atmos Mid-Tex established that the utility maintains its books and records in accordance with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts prescribed for Natural Gas Companies.

31. Atmos has established that the utility has fully complied with the books and records requirements of Rule 7.310 and the amounts included therein are therefore subject to the presumption encapsulated in Rule 7.503 that these amounts are reasonable and necessary.

Scope of Proceeding

32. Atmos Energy Corporation and Staff of the Railroad Commission each filed a motion to limit issues identifying nineteen issues ripe for issue preclusion due to prior review and determination of methodology.

33. Continued use of the following methodology was found to be reasonable in this case and therefore, precluded from further litigation:

> Continued use of the three-year average uncollectibles expense as approved in GUD Nos. 9762 and 9869 (Mid-Tex).
>
> Continued use of an income tax factor of 0.5385 to the dollar return on equity included in the revenue requirements computed based on the statutory income tax rate of 35 percent as approved in GUD Nos. 9670, 9762, and 9869 (Mid-Tex); GUD Nos. 10041, 10084, and 10085 (West Texas Division; and GUD No. 10000 (APT).
>
> Continued use of the equal life group (ELG) method for calculating depreciation expenses as approved in GUD Nos. 9762 and 9670 (Mid-Tex); GUD Nos. 10041, 10084, and 10085 (West Texas Division); and GUD No. 10000 (APT).
>
> Continued exclusion of sales, transfers of property, outliers and reimbursed retirements from the life and salvage analysis used to calculate depreciation as approved in GUD No. 9762 and 9670 (Mid-Tex).
>
> Continued use of preferred customer sample methodology as discussed in GUD Nos. 9762 and 9869 (Mid-Tex) to determine collection lag in the lead-lag study.
>
> Continued use of the four-factor formula approved by the Commission as part of the cost allocation methodology for Shared Service Unit expenses approved in GUD Nos. 9762 and 9869 (Mid-Tex); GUD Nos. 10041, 10084 and 10085 (West Texas Division); and GUD No. 10000 (APT).

(Excluding, calculation of the individual components used in the methodology.)

Continued use of 13-month averages for materials and supplies and prepayments as approved in GUD Nos. 9670, 9762, and 9869 (Mid-Tex); GUD Nos. 10041, 10084 and 10085 (West Texas Division), and GUD No. 10000 (APT). (Excluding the actual unadjusted amounts included in the calculation).

Continued use of a minimum distribution system of 2-inch pipe for allocation purposes. (Excluding issues related to the input values).

Continued use of system-wide rates for the Atmos Mid-Tex Division.

Continuing to cease accrual of depreciation expense once an account is fully accrued as in GUD Nos. 9762 and 9670 (Mid-Tex).

Inclusion of prepayment as an "other" rate base item in the lead-lag study as required in GUD Nos. 9869 and 9762.

The affiliate standard encompassed in Tex. Util. Code Ann § 104.055(b) shall not apply to intracompany transactions.

Elimination of certain shared services categories, or cost centers, the cost of service as required in GUD Nos. 9762 and 9869 (Mid-Tex); GUD Nos. 10041, 10084, and 10085 (West Texas Division); and GUD No. 10000 (APT). These include preclusion of the re-litigation of the following cost centers: 1132 (Investor Relations), 1350 (Dallas Non-Utility Operations), 1507 (Dallas Texas Lobbying), 1904 (Dallas Supplemental Executive Benefit Plan), and 1908 (Dallas Supplemental Employee Benefits). This limitation shall apply to any successor cost center in the event that one of the specifically identified cost center has been renamed or its function reassigned.

Rate Case Expenses

34. Rate case expenses were severed into a separate docket, GUD No. 10194, upon the request of the parties.

Hearing

35. A notice of hearing was issued on July 12, 2012.

36. The hearing on the merits in this matter was conducted from September 12, 2012 through September 21, 2012.

37. The evidentiary record was closed on November 13, 2012.

Shared Services Unit Allocation

38. Atmos Energy Corporation consists of seven distribution utilities, a regulated pipeline and various subsidiaries.

39. Technical and support services are provided to the operating divisions by centralized shared services departments primarily located at the Atmos headquarters in Dallas.

40. The collective shared services departments are referred to as the Shared Services Unit (SSU).

41. The centralized functions provided by the Shared Services Unit include, but are not limited to, accounting, gas supply, human resources, information, technology, legal, rates and customer support.

42. The Shared Services Unit is comprised of two divisions, as follows: (a) Shared Services – Customer Support (sometimes referred to as "SSU Customer Support"), which provides functions that include billing, customer call functions and customer support related functions; and (b) Shared Services – General Office (sometimes referred to as "SSU General Office"), which provides functions that include accounting, human resources, legal, rates, risk management and others.

43. The company's Cost Allocation Manual establishes a reasoned methodology for the allocation of costs among the company's divisions.

44. The company's Cost Allocation Manual has been approved in several of the jurisdictions where Atmos Energy provides service and ensures a uniform allocation of costs.

45. The cost allocation manual requires that certain costs be allocated on the company's general ledger utilizing the allocation methodologies described in detail in the manual.

46. Shared services that are not allocated on the company's general ledger are allocated based upon a Composite Factor (Composite Factor) or Customer Factor (Customer Factor).

47. The Composite Factor was derived based upon a four-factor formula comprised of the simple average of the relative percentage of gross plant in service, the relative percentages of the average number of customers, the relative percentages of direct operating and maintenance expenses for each of the company's operating divisions, and operating income.

48. The use of the four-factor formula was first required by the Commission in GUD No. 9670 and its use was affirmed in GUD Nos. 9762, 9869, and 10000.

49. The Customer Factor is derived based on the average number of customers in each operating division that receives allocable costs for services provided.

50. The Customer Factor was proposed by the company and subsequently approved by the Commission in GUD Nos. 9670, 9762, and 9869.

51. Prior to August 1, 2012, the Atmos Energy Kentucky/Mid-States Division was an operating division that operated in more than 420 communities across Georgia, Illinois, Iowa, Kentucky, Missouri, Tennessee and Virginia.

52. On May 12, 2011, Atmos entered into an agreement to sell all of its natural gas distribution assets located in Missouri, Illinois, and Iowa to Liberty Energy (Midstates) Corporation (Liberty Energy), an affiliate of Algonquin Power & Utilities Corp.

53. Any interim transactional agreement between the company and Liberty Energy is temporary.

54. The fact of this transaction was known by May 12, 2011, before the end of the test year in this case.

55. The transaction closed August 1, 2012.

56. The company has not eliminated a division, it has only reduced the service area of the affected division, the Kentucky/Mid-States Division.

57. There have been no changes to the Shared Service Unit attributable to the transaction, the staffing level of the Shared Services Unit has not changed, no changes to the staffing level of the Shared Services Unit are anticipated and future staffing level changes are not known and measurable.

58. The factors used in this case were calculated excluding data from the operations in Illinois, Iowa and Missouri that were sold.

59. The company applied the same methodology that was previously approved to calculate the composite allocation factors.

Operation and Maintenance Expenses

60. The overall operation and maintenance expense requested by Atmos in the *Statement of Intent* as filed was $152,490,153.

61. Atmos has not established that the operation and maintenance request was just and reasonable.

62. The operation and maintenance request reflected in the attached Schedule F-1 is just and reasonable.

63. Several issues related to the calculation of the company's operation and maintenance expense have previously been considered by the Commission and judicial notice of the following Final Orders is hereby taken:

A. Tex. R.R. Comm'n, *Petition for De Novo Review of the Reduction of the Gas Utility Rates of Atmos Energy Corp., Mid-Tex Division, by the Cities of Blue Ridge, Caddo Mills et al; Atmos Energy Corporation Statement of Intent to Change Rates in the Atmos Energy Corp., Mid-Tex Division Gas Utility System; Petition for Review from the Actions of Municipalities Denying Rate Request,* Docket No. 9670 (Gas Utils. Div. June 13, 2007) (Final Order) (GUD No. 9670).

B. Tex. R.R. Comm'n, *Statement of Intent filed by Atmos Energy Corporation to Increase Utility Rates within the Unincorporated Areas Served by the Atmos Energy Corp., Mid-Tex Division and Petition for De Novo Review of the Denial of the Statement of Intent filed by Atmos in Various Municipalities*, Docket No. 9762 (Gas Utils. Div. June 24, 2008) (Final Order) (GUD No. 9762)

C. Tex. R.R. Comm'n, *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*, Docket No. 9869 (Gas Utils. Div. February 23, 2010) (Final Order Nunc Pro Tunc) (GUD No. 9869).

D. Tex. R.R. Comm'n, *Statement of Intent to Change the Rate CGS and Rate PT of Atmos Pipeline – Texas,* Docket No. 10000 (Gas Utils. Div. April 18, 2011) (Final Order) (GUD No. 10000).

Base Payroll

64. The test-year level of base payroll was not contested by the parties.

65. Atmos proposed a post-test year adjustment to the test-year level of base payroll based upon the level of employee expense as of October 2011.

66. The base payroll adjustment was consistent with the methodology approved in GUD No. 9869.

67. Expenses for compensation to employees in SSU cost centers that are not allocable to Mid-Tex have been removed and salaries below the line have been removed.

68. The company's post-test-year adjustment to base labor is just and reasonable and the base labor amounts included in the attached schedules are reasonable.

69. The O&M expense factor applied to SSU Customer Support post-test-year base labor adjustment was 89.60% and the O&M factor applied to post-test-year base labor adjustment SSU General Services was 97.72%.

70. The factor was based upon the capitalization ratios experienced by the company during the test year.

71. The proposed O&M expense factors based upon the capitalization ratios experienced by the company are just and reasonable.

72. Atmos has established that its proposed base payroll is just and reasonable and the attached Schedule WP_F-2.1 is just and reasonable.

Medical and Dental Benefits

73. The company provided a post-test-year adjustment to medical and dental benefit expenses in order to align the benefits expense at the most current benefit rates available.

74. The company used the actuarial data prepared by Holmes Murphy to calculate the proposed adjustment and used employee data and claims information provided by health care providers.

75. Atmos has removed expenses for SSU employees in cost centers that are not allocable to the Atmos Mid-Tex Division.

76. Atmos has established that its proposed level of Medical and Dental benefits expenses are reasonable and the medical and dental benefits expenses included in the attached Schedules F-1 and WP_F-2.2 are just and reasonable.

Pension Expense

77. The company included an adjustment to the test-year level of pension expenses in its revenue requirement calculation.

78. The adjustment calculated the benefit expense at the most current benefit rates available.

79. The adjustment was calculated based upon the fiscal year 2012 Towers Watson (Towers Watson) actuarial data for the Atmos Mid-Tex Division and SSU.

80. The methodology employed was consistent with the methodology applied in GUD No. 9869 and GUD No. 10000.

81. Accounting standards require that the pension and OPEB asset value be calculated as of the fiscal year-end.

82. The fiscal year-end for Atmos is September 30th of each year.

83. The company moved to an account-based pension plan in that year and eliminated pension benefit accruals based on final average pay.

84. In 2010, the company evaluated alternatives to offering a Pension Account Plan to new employees and effective October 1, 2010, the company closed the plan to new employees.

85. This history of the company's management of its pension accounts established the prudent management of the pension account plans by the company.

86. The key factor determining the pension account expense is the discount rate.

87. The discount rate is a market factor outside the control of the company.

88. The calculation of the post-test-year adjustment for the pension account plan is consistent with the calculation applied in GUD No. 9869 and GUD No. 10000.

89. Atmos has established that its proposed level of pension expense is reasonable and the pension expense included in the attached Schedule F-1 and WP_F-2.3 is just and reasonable.

Supplemental Executive Pension and Benefits

90. The company calculated an adjustment to the test-year level of expenses for Supplemental Executive Benefit Plans (SEBP) and Supplemental Employee Retirement plans (SERP).

91. SEBP and SERP are nonqualified, deferred compensation plans which provide supplemental retirement income, death and disability benefits for certain executive employees of Atmos.

92. Atmos maintains three separate plans: (1) a Supplemental Executive Benefit Plan for officers, division presidents and certain other employees employed on or before August 12, 1998; (2) a supplemental Executive Retirement Plan for eligible employees who become officers or division presidents after August 12, 1998; and (3) a SERP effective August 4, 2009 for corporate officers, division presidents or other employees selected by the board of directors.

93. SERP and SEBP are necessary for the recruitment and retention of talented employees and provide a benefit to both shareholders and customers.

94. Removal of the SERP for employees of the Atmos Mid-Tex Division would disadvantage Atmos executives and will impact the company's recruitment and retention of talented employees.

95. It is reasonable to balance the burden of the recovery of the expense for SERP and SEBP among shareholders and customers.

96. Shared Services Unit corporate officers, division directors and other employees selected by the board of directors may be eligible for SEBP and SERP.

97. Atmos Mid-Tex corporate officers, division directors and other employees are selected by the board of directors.

98. The post-test-year adjustment was intended to calculate benefits expenses at the most current benefit rates available at the time the rates approved by this Final Order are effective.

99. The post-test-year adjustment was calculated based upon an actuarial report prepared by Towers Watson.

100. Atmos removed all expenses related for SEBP and SERP for the Shared Services Unit.

101. Atmos included expenses related to those plans for employees of the Atmos Mid-Tex Division.

102. The company's treatment of SEBP and SERP was consistent with the treatment approved in GUD No. 9762, GUD No. 9869 and GUD No. 10000.

103. The burden of the recovery of expenses related to SEBP and SERP is balanced by including Atmos Mid-Tex Direct employees in the calculation of rate base and excluding expenses for SEBP and SERP related to Shared Services Employees.

104. The company's proposal in this case is consistent with prior precedent.

105. Based upon the record in this case, the total adjusted expenses for SEBP and SERP by the Shared Services Unit was $7,585,854 and the allocable portion of this expense, based upon a 45.23% composite allocation, was $3,431,082 ($7,585,854 x. 43.23%).

106. The operation and maintenance expense factor of the Shared Services Unit SEBP and SERP plans is 41.51%.

107. The updated operation and maintenance expense portion for SEBP and SERP for the Shared Services Unit, based upon an operations and maintenance expense factor of 41.51% was $1,424,242 ($3,431,082 x 41.51%). Atmos has not included this amount in the revenue requirement calculation.

108. The SERP updated expense for the employees of the Atmos Mid-Tex Division is $143,390.

109. The updated operation and maintenance expense portion for SERP, based upon an expense factor of 33.42% was $47,921 ($143,390 x 33.42%). Atmos has included this amount in the revenue requirement calculation.

110. The total updated operation and maintenance expenses for SERP/SEBP was $1,472,163.

111. The company has included only 3.25% of the SERP and SEBP expenses, totaling $47,921, of this expense in the revenue requirement calculation.

112. The company's proposed treatment of SERP and SEBP is consistent with prior precedent that balances the burden of the recovery of this expense between shareholders and customers by allowing recovery of the Atmos Mid-Tex Division and disallowing recovery of the Shared Services Unit Expenses.

113. Atmos has established that its proposed level of SERP and SEBP is just and reasonable and the expenses included for SERP in the attached Schedule F-1 and WP_F-2.3 are just and reasonable.

114. Consistent treatment provides regulatory certainty and it is reasonable that SERP and SEBP be apportioned by applying the methodology approved in prior proceedings.

115. Continued balancing of this expense by allowing recovery of the Atmos Mid-Tex Division SERP and disallowing recovery of Shared Services Unit expense for SEBP and SERP may not be reasonable in future proceedings.

116. It is reasonable that the company not be bound by prior precedent in allocating the burden of SERP and SEBP expenses and it is reasonable that the company explore a more balanced and transparent apportionment of the burden of this expense in future proceedings.

FAS 106 Expense

117. Atmos provided a post-test-year adjustment to FAS 106 expenses intended to calculate benefits expenses at the most current benefit rates available.

118. The treatment of FAS 106 expenses and the proposed post-test-year adjustment is consistent with the treatment of this expense in GUD No. 9869 and GUD No. 10000.

119. The adjustment was calculated based upon the fiscal year 2012 Towers Watson actuarial data for Mid-Tex and the Shared Services Unit.

120. In GUD No. 10000 the Commission ordered that a division of Atmos Energy Corporation, the Atmos Pipeline Division, establish an external fund for FAS 106 expenses.

121. An external fund limits the use of those funds to the payment of benefits to or on behalf of retirees and the company does not have access to those funds for other purposes

122. The creation of an external fund was consistent with the treatment of that fund in other jurisdictions where Atmos provided service: Colorado, Iowa, Kansas, Mississippi, Missouri, Tennessee, and Virginia.

123. Pursuant to the requirements of the Final Order in GUD No. 10000 Atmos established an external fund for the Atmos Pipeline – Texas Division.

124. An external fund was subsequently established for the Atmos Mid-Tex Division and the first contribution made to the external fund for the Atmos Mid-Tex Division was on April 6, 2012.

125. In the past, the company's shareholders have had to fund the difference between the FAS 106 expense included in rates and the accrual on the company's books when there has been a shortfall in the amounts collected through rates.

126. The amount of any accumulated customer contribution that might be applicable to a fund is not readily known and measurable.

127. The Final Order in GUD No. 10000 was issued on June 27, 2011. The company established a separate fund for FAS 106 for the Atmos Mid-Tex Division in April 2012.

128. The payment made to that fund, $1,474,249 related to the fiscal period from January 1, 2012 through March 31, 2012.

129. The record in this case does not establish that the timing of that payment, seven months after the issuance of the Final Order in GUD No. 10000, was unreasonable.

130. The record in this case does not establish that ratepayer-provided funds were available to make an earlier payment into the external fund.

131. Atmos has established that FAS 106 expense included in the attached Schedules F-2 and WP_F-2.3 are just and reasonable.

Incentive Compensation

132. The company provides incentive compensation packages to two broad categories of employees: (a) Executive and management employees, and (b) all other employees.

133. Management and executive employees are eligible to participate in a short term management incentive plan (MIP) and all other employees are eligible to participate in variable pay plans (VPP).

134. Management and executive employees are also eligible to participate in long-term incentive plans (LTIP).

135. MIP, VPP, and LTIP are available to employees in the Shared Services Unit and to direct employees of the Atmos Mid-Tex Division.

136. The MIP and VPP plans provide eligible employees an opportunity to earn a cash-based incentive reward.

137. The LTIP incentive has historically been in two forms: Time-lapse restricted shares and performance-based restricted share units.

138. The company has excluded from its cost of service calculation expenses related to VPP and MIP costs allocated to the Mid-Tex Division.

139. Atmos has included the Mid-Tex direct costs for VPP and MIP, as well as, the Mid-Tex direct and SSU allocated LTIP costs.

140. The company's filing is consistent with Commission precedent related to divisions of Atmos Energy Corporation that are subject to the jurisdiction of the Commission: GUD Nos., 9670, 9762, 9869, and 10000.

141. The company's incentive compensation plans have not changed since GUD No. 10000.

142. Removal of all incentive compensation programs will hamper the retention and requirement of qualified employees.

143. The company's incentive compensation program is compatible with industry standards.

144. The company's incentive compensation programs are directly tied to improvements in performance, productivity, service, expense management, and other performance factors that directly impact earnings per share.

145. The plans encourage top management to motivate, recognize, and reward employee performance.

146. The vast majority of investor-owned gas distribution utilities have adopted incentive compensation plans as an integral element of their compensation programs.

147. The record in this case established the incentive compensation plans of Atmos include metrics that are directly relevant to customer satisfaction.

148. The record in this case established that financial metrics in the incentive compensation plan provide a benefit to customers and shareholders.

149. Positive financial performance requires the achievement of rate-based revenues while at the same time controlling operating expense levels.

150. Positive financial performance requires increased employee productivity, customer retention and satisfaction, adherence to safety and environmental concerns, control of operations and maintenance expenses minimizing operating expense levels to maximize earnings per share.

151. In an effort to keep medical and dental benefit expenses in check the company instituted programs to improve the health of employees.

152. The company has experienced a declining level of medical and dental benefits expenses.

153. Evidence in the record established that Atmos' calculation of the billing lag has changed from 4.47 days in a prior proceeding to 1.74 days. This evidences an improvement that provides financial returns to the company, reduces the O&M expenses included in the cost of service calculation, and provides timely consumption information to consumers.

154. Atmos and the City of Dallas acknowledged that improved practices at Atmos extend the service life of the company's assets. This evidences that actions by all employees directly impact safety, reduce costs included in the cost of service by extending the service life of company assets, and improve the financial returns of the company.

155. The company's operations and maintenance expenses have remained stable since 2008.

156. The company's incentive compensation plan benefits all constituents of Atmos: customers, shareholders, and employees.

157. Atmos established that its treatment of incentive compensation is consistent with Commission precedent applicable to Atmos in general, and Atmos Mid-Tex, in particular.

158. The company's treatment of incentive compensation expenses is just and reasonable and Atmos has established that expenses for incentive compensation included in the attached Schedules F-1 are just and reasonable.

159. It is reasonable to balance the burden of the expenses related to incentive compensation between shareholders and customers as both benefit from incentive compensation programs.

160. Removal of all MIP, VPP, and LTIP expenses from the revenue requirement would require the shareholders to bear all expenses related to incentive compensation programs that benefit shareholders and customers.

161. Previous decisions balanced the burden of the expenses related to incentive compensation by including expenses related to Shared Services LTIP plans and expenses related to the

MIP, VPP, and LTIP plans of the Atmos Energy Corporation Divisions that are subject to the jurisdiction of the Commission.

162. MIP and VPP expenses related to the Shared Services totaled \$5,569,561 and 37.60% of those expenses, totaling \$2,094,154 (\$5,569,561 x 37.60%), would have been allocable to the operation of maintenance expenses of the Atmos Mid-Tex Division.

163. Pursuant to Commission precedent, the company excluded those amounts from the revenue requirement of the company.

164. LTIP expenses related to the Shared Services that were allocated to the Atmos Mid-Tex Division as part of the revenue requirement calculation totaled \$1,241,636.

165. MIP, VPP, and LTIP expenses for employees of the Atmos Mid-Tex Division totaled \$825,291.

166. MIP, VIP, and LTIP operation and maintenance expenses totaled \$4,161,081; Pursuant to precedent, the company has only included \$2,066,927 of those expenses in the revenue requirement or 49.67%.

167. The company's proposed treatment of incentive compensation is consistent with prior precedent that balances the burden of the recovery of this expense between shareholders and customers by allowing recovery of the Atmos Mid-Tex Division and disallowing recovery of the Shared Services Unit Expense.

168. Consistent treatment provides regulatory certainty and it is reasonable that the expenses be apportioned by applying the methodology approved in prior proceedings.

169. Continued balancing of this expense by allowing recovery of the Atmos Mid-Tex Division VPP, MIP, and LTIP expenses, Shared Services Unit LTIP expenses and disallowing recovery of Shared Services Unit expense VPP and MIP may not be reasonable in future proceedings.

170. It is reasonable that the company not be bound by prior precedent in allocating the burden of MIP, VPP, and LTIP expenses and it is reasonable that the company explore a balanced and transparent apportionment of the burden of this expense.

Amortized Injuries and Damages

171. Atmos seeks an adjustment to the cost of service in this case in the amount of \$600,000 in amortized costs for injuries and damages in excess of insurance coverage for damages and injuries associated with the three incidents in Wylie, Cleburne and Lutrell.

172. Atmos is responsible for a \$1 million insurance deductible per incident and the insurance generally covers the settlement and litigation costs of this type of loss.

173. The incidents in Cleburne and Wylie were included in the approved level of expense in GUD Nos. 9762 and 9869 and an adjustment allowed a five-year amortization of $200,000 per incident per year to recover the $1 million insurance deductibles.

174. The $600,000 adjustment proposed by Atmos in this proceeding included (a) an amortization of the prior two incidents in the amount of $200,000 per incident per year; and (b) a $200,000 adjustment per year for five years for the incident in Lutrell.

175. A five (5) year amortization period for the Lutrell incident is the same period that was previously approved for the incidents in Cleburne and Wylie and is just and reasonable.

176. The recovery of the amortized amounts for the incidents in Wylie and Cleburne will end June 2013 and an over-recovery is likely as the rates in this case will not go into effect until December 2012.

177. It is just and reasonable for Atmos to reimburse ratepayers for any over-recovery of these amounts during the next IRA, RRM, or Statement of Intent proceeding, whichever occurs first.

Affiliate Expenses: Blueflame Insurance Expense

178. Insurance services required by Atmos Energy are acquired from Blueflame.

179. Blueflame is a wholly owned subsidiary of Atmos Energy that provides insurance for all of the company's divisions.

180. The day-to-day management of Blueflame is conducted by Aon Insurance Managers, Ltd., (Aon) a third-party captive manager.

181. Aon provides Atmos Energy with consultation services.

182. All of the Atmos Mid-Tex Division property, plant, and equipment are covered through property insurance provided by Blueflame.

183. Insurance services provided by Blueflame are at cost and without markup.

184. The cost of insurance coverage is allocated among the Atmos Energy divisions and subsidiaries based upon the annual plant balance.

185. The rate of rate of insurance was $0.085 per $100 of gross plant.

186. Atmos has established that the expenses for Blueflame are (a) reasonable and necessary and (b) the price charged to the Atmos Mid-Tex Division is not higher than the prices charged by the supplying affiliate to its other affiliates or division or to a non-affiliated person for the same item or class of items.

187. The services provided by Blueflame have been found to be reasonable and necessary in the following prior proceedings: GUD Nos. 9670, 9762, 9869, 10000, 10041, 10084 and 10085.

188. There have been no changes in the management of Blueflame since the approval of the expenses related to Blueflame in GUD Nos. 9670, 9762, 9869, 10000, 10041, 10084 and 10085.

189. The company also included an adjustment to include the amortization of a Cancellation Fee approved in GUD No. 9762.

190. Atmos is entitled to recovery of the Cancellation Fee expense, however, it expires in June 2013.

191. It is just and reasonable for Atmos to reimburse any over-recovery of the Cancellation Fee amounts during the next IRA, RRM or Statement of Intent proceeding, whichever occurs first.

192. The company has not established that insurance expenses for construction work in progress (CWIP) have been excluded from the revenue requirement calculation.

193. An adjustment totaling $11,865 to remove insurance related expenses for CWIP is just and reasonable.

Rate Base

194. The company's test year in this proceeding is the twelve-month period ending September 31, 2011 and the company adjusted the plant balances through March 31, 2012.

195. The adjustment to plant was identified in the original *Statement of Intent* proceeding that was filed on May 31, 2012, and the adjustment was also reflected in the appeal filings.

196. All changes to net plant, including changes to accumulated deferred income taxes were known and measurable and the company provided a detailed listing of all plant additions through March 31, 2012.

197. A rate-base calculation founded upon a test year ending September 31, 2011, as adjusted for known and measurable changes through March 31, 2012, is just and reasonable.

198. The Commission has previously allowed an update to plant balances through a period that ended six months after the end of the test year.

199. A utility may establish a reserve for pensions paid to retirees and other post-employment benefits (OPEB) that related to retiree health care, dental care, and other post-employment health benefits.

200. Based upon an actuarial analysis of the pension costs, the Atmos Mid-Tex Division has established that that a shortage exists in the funding of pensions and OPEB and that a regulatory asset of $1,954,911, in rate base is reasonable and a corresponding amortized amount, totaling $195,491 to the company's operating and maintenance expense is also just and reasonable.

201. It is reasonable that the pension expense established in the last general rate case, GUD No. 9869, be applied to determine the appropriate baseline for the measure for calculating the regulatory account asset associated with pensions and OPEB.

202. The company's calculation of the reserve calculation mandated by Section 104.059 of the Texas Utilities Code was consistent because the allocation factors applied to determine the baseline were the same as the allocation factors applied to the updated expenses for purposes of calculating the regulatory asset.

203. It is reasonable to update the regulatory asset by applying and flowing through all corrections applicable to the calculation of the current pension expense.

204. The base year level of pension expense requested is just and reasonable and the expense level requested was calculated pursuant to GAAP and applicable statutes.

205. Accordingly, following pension expense, as reflected on the attached Examiners' Schedule 6, are hereby adopted:

Section 104.059 Benchmarks

	PAP (FAS 87)	Post-Retirement Medical Plans (FAS 106)	SERP
SSU Allocated to Mid-Tex	$2,756,682	$1,971,341	
Mid-Tex Direct	$8,087,526	$7,092,975	$143,390
Total	$10,844,208	$9,064,316	$143,390

Accumulated Deferred Income Taxes

206. Deferred taxes arise because of timing differences between recognition of certain items for book purposes versus tax purposes.

207. The company's calculation of ADIT related to NOL matches the ADIT liabilities to the ADIT NOL asset created by those deductions.

208. Inclusion of the consolidated ADIT asset for tax NOLs results in the inclusion of non-regulated tax matters in rates.

209. In order to ensure that rates reflect only the NOL attributable to the company's regulated utility operations, the effect of the non-regulated ADIT asset for income tax NOLs must be excluded.

210. Atmos has established that its calculation of the ADIT asset related to NOLs was just and reasonable.

211. Atmos is required to pay an Alternative Minimum Tax (AMT) amount if the company's regular tax is less than the calculated AMT.

212. The AMT credit reflects a cash disbursement to the government that will be realized in the future when the company reduces regular tax. Accordingly, it represents cash that the company has on deposit with the government that it is unable to use.

213. Atmos has established the AMT ADIT asset is just and reasonable.

214. Atmos has not included a component for construction work in progress (CWIP) accordingly it is reasonable to exclude the associated ADIT balance.

215. Atmos has included an ADIT asset, totaling $1,390,603, associated with uncollectible accounts.

216. Atmos did not recognize the accrued reserve for uncollectible accounts in rate base and it is not reasonable to include the ADIT associated with this reserve in rate base.

217. Uncollectible expenses were included in the company's expenses for purposes of calculating the revenue requirement and it was included in the cash working capital analysis for purposes of calculating the cash working capital requirement of the company.

218. Accordingly, ratepayers provided funds are available to address any tax liability incurred from uncollectibles.

219. Atmos included ADIT amounts associated with a State Net Operating Loss (NOL) tax asset and related Federal Tax on the State NOL and the company has established that the ADIT amounts related to the State and Federal Tax NOL is just and reasonable.

220. The company calculates an annual effective tax rate for income tax expenses and in order to properly record income tax expenses, an ADIT entry is made to record the difference between actual expense and projected expense.

221. Atmos has established that its ADIT entry associated with this transaction is just and reasonable.

FAS 106 Liability

222. Atmos included an ADIT balance for FAS 106 Liability.

223. Atmos Mid-Tex established an external fund for its FAS 106 reserves and although FAS 106 is not included in rate base, the company has established a regulatory asset related to these expenses that is included in rate base.

224. The external fund was established before the creation and recognition of the regulatory asset authorized by Section 104.059, and it is reasonable that in future proceedings the company be allowed to reexamine the efficacy of an external fund.

225. The FAS 106 funds are governed by strict accounting standards (GAAP) and financial reporting requirements under Accounting Standards Codification (ASC) 960.

226. The evidence in this proceeding was insufficient to establish that the FAS 106 reserve represents a source of zero-cost capital.

227. Company shareholders have had to fund the FAS 106 account as well as customers.

228. Atmos has established that its treatment of the FAS 106 reserve is just and reasonable and the inclusion of an ADIT balance related to FAS 106 is just and reasonable.

Cash Working Capital

229. The Atmos Mid-Tex Division prepared a lead-lag study to determine the cash working capital needs of the division for the test year ending September 30, 2011.

230. Atmos has established that its proposed cash working capital is just and reasonable.

231. In GUD No. 9762, the Commission ordered the use of a one-day billing lag.

232. An average billing lag of one business day produces a 1.4 calendar day lag.

233. Detailed evidence was provided regarding the billing process and the evidence in this case supports a billing lag of 1.74 days.

234. The company has improved its billing process and reduced the billing lag from 4.47 days requested in GUD No. 9670 and 2.72 days requested in GUD No. 9762 to 1.74 days requested in this case.

235. The calculation of the O&M – Non-labor expense lag adjustment in the cash working capital study is consistent with Commission precedent for Atmos and its various divisions.

236. There is insufficient evidence to support segregating categories of O&M – Non-labor expense for individual treatment.

237. Grouping O&M – Non-labor expenses for purposes of calculating a cash working capital study is just and reasonable.

238. Atmos established that the data used in calculating the O&M – Non Labor Expense lag, as adjusted to dampen the effect of disproportionate units in the sample, is just and reasonable.

239. Uncollectible expenses impose a financial requirement on the utility and is properly included in the calculation.

Depreciation

240. The company prepared a depreciation study for its Atmos Mid-Tex Division and Shared Services Unit.

241. Functional level depreciation rates are being applied to determine the annual accrual for depreciation expense for the Atmos Mid-Tex Division.

242. Transition to an account-specific accounting based upon a theoretical reserve will achieve the most accurate depreciation rates.

243. The proposed reallocation methodology is consistent with GUD Nos. 9902, 10000, 10038, and 10041.

244. There is an insufficient evidentiary basis upon which to apply a book reserve depreciation methodology in this case.

245. The company has not established that the average service life calculation for Mid-Tex Account 374.02 is just and reasonable.

246. In the 100-year history of this account there has been less than 1%, $17,000 out of $23 million dollars that has been retired.

247. Land rights should not retire prior to the mains associated with the land right and an adjustment of the average service life for Account 374.02 is necessary to avoid this result.

248. An average service life for Account 374.02 of 100R4 is just and reasonable.

249. Atmos has established that the average service life for Mid-Tex Account 375, Structures, of 54R1.5 is just and reasonable.

250. Atmos has established that the average service life for Mid-Tex Account 376, Cathodic Protection Mains of 60R3 is just and reasonable.

251. Atmos has established that the average service life for Mid-Tex Account 376.01, Mains Steel, of 70R0.5 is just and reasonable.

252. Atmos has established that the net salvage calculation for Mid-Tex Account 376.01, of a negative 105% is just and reasonable.

253. Atmos has not established that the average service life for Mid-Tex Account 376.02, Mains Plastic, is just and reasonable.

254. Atmos has established that the net salvage calculation for Mid-Tex Account 376.02, Mains Plastic, of a negative 40% is just and reasonable.

255. The weight of the evidence in this case indicates that the placement bands used by Atmos in its analysis of this account requires an estimate of approximately 94% of the unknown balance of the survivor curve.

256. A 1962 placement band provides more credible statistical results upon which to determine the average service life for Mid-Tex Account 376.02.

257. Atmos has established that the average service life for Mid-Tex Account 378, Measuring and Regulating Station Equipment, Account 379, City Gate Equipment, and Account 385, Industrial Measuring and Regulating Equipment of 57R1 is just and reasonable.

258. Atmos has established that the average service life for Mid-Tex Account 380, Distribution Services, is just and reasonable.

259. Atmos has established that the average service life for Mid-Tex Account 381, Meters, Account 382, Meter Installations, and Account 383, House Regulators of 37R1is just and reasonable.

260. Atmos has established that the average service life for Mid-Tex Account 390, General Plant Structures and Improvements of 45R2.5 is just and reasonable.

261. Atmos has established that the net salvage calculation for Mid-Tex Account 390, General Plant Structures and Improvements of a negative 5% is just and reasonable.

262. Atmos has established that the average service life for SSU Account 390, Structures and Improvements of 40R2 is just and reasonable.

263. Atmos has established that the net salvage calculation for SSU Account 390, Structures and Improvements of zero is just and reasonable.

264. Atmos has established that the proposed average service life for SSU Account 399.08, Application Software is just and reasonable.

265. Atmos has established that an increase from the current 10-year average service life to a 12-year average service life is just and reasonable.

266. The GAP guidance for software (AICPA-SOP 98-1) shows that the history of rapid changes in technology software often has relatively short useful life.

267. AICPA guidance provides the input of company personnel involved in retiring and replacing software dictates the average service life assessment.

268. An average service life for SSU Account 399.08, Application Software of 12R5 is just and reasonable.

Rate of Return

269. It is reasonable to use Atmos' actual, consolidated capital structure composed of 48.31 percent long-term debt and 51.69 percent common equity as reported on the company's quarterly Form 10-Q filed with the Securities and Exchange Commission, as of March 31, 2012.

270. Atmos' capital structure of 48.31 percent long-term debt and 51.69 percent common equity is within the range of the average calculated capital structure of the comparable, proxy groupings of companies selected by Atmos and Staff of the Railroad Commission of Texas.

271. Atmos' short-term debt is properly excluded from the capital structure of the company because it is utilized to finance seasonal gas costs and is not a permanent element of the company's capital structure.

272. It is not reasonable to include the company's goodwill, or acquisition adjustments in Atmos' capital structure because Atmos has removed goodwill from rate base in accordance with the principle that utility rates be set based on original cost.

273. A cost of debt of 6.50 percent for Atmos for purposes of determining Atmos' weighted average cost of capital and allowable rate of return is just and reasonable.

274. Atmos established that the treasury lock transaction is just and reasonable as the company updated its filing to differentiate between realized and unrealized treasury instruments in its ADIT calculation.

275. The gain from the treasury lock transaction is not related to the operations of the Atmos Mid-Tex Division and it would be inappropriate to include the effect of the transaction in the revenue requirement.

276. The preponderance of the credible evidence in this docket does not establish use of the Quarterly Dividend DCF model because it overstates the cost of equity.

277. In the Constant Growth DCF model, the preponderance of the credible evidence in this case demonstrates that use of a growth rate utilizing analyst estimates of future earnings

per share (EPS) for the individual companies in the proxy study are reliable, accurate and capable of forecasting the future earnings growth with accuracy and reliability.

278. The results of the CAPM model utilized by Staff of the Railroad Commission of Texas is reasonable, utilizing a 10-year Treasury bond average yield for the six-month period added to the product of the mean Beta value and calculated *ex-ante* risk premium, resulting in a range of values from 5.97 percent to 9.84 percent, with a mean Beta value cost of equity estimate of 7.87%.

279. It is reasonable to use a cost of equity of 10.50 percent for purposes of determining Atmos' weighted average cost of capital and allowable rate of return to reflect the recent precedent regarding this utility and the cost of equity range proposed by the applicant.

280. An overall rate of return of 8.57 percent based on Atmos' weighted average cost of capital is just and reasonable.

Interim Rate Adjustment Review

281. Atmos Mid-Tex has established that the interim rate adjustments made from 2010, 2011 and 2012 were just and reasonable.

282. Atmos Mid-Tex established that the interim rate adjustment requests made in 2010, 2011 and 2012 were carefully scrutinized to include only appropriate expenses.

Classification of Costs and Allocations Among Customer Classes

283. It is reasonable to allocate the overall cost of service to three classes of customers: (1) residential, (2) commercial, and (3) industrial and transportation.

284. Allocation of costs to the different customer classes in three steps: (1) functionalization, (2) classification, and (3) allocation.

285. In order to classify costs the company applied a minimum system study to classify costs as either customer related or capacity related.

286. The use of a minimum system study is just and reasonable.

287. Atmos filed with the U.S. Department of Transportation ("DOT") records established that Atmos had 153,690,240 feet of mains in the system.

288. The last three Mid-Tex minimum system studies reflect 147,761,265 feet of main, in GUD Nos. 9400, 9670 and 9869.

289. The company applied a new accounting methodology, based upon retirement units, to measure the number of feet of mains.

290. The company has not established that its revised accounting methodology produced a just and reasonable result.

291. The record in this case established that, for purposes of the minimum system study the appropriate measure is 153,690,240.

292. The most reliable evidence of the quantity of 2 inch main is the U.S. DOT records that Atmos had 153,690,240 feet of mains in the system for calendar year 2011.

Rate Design

293. Billing determinants are units of service to which the company's distribution rates are applied.

294. The company prepared a billing determinants study to establish its billing determinants.

295. The billing determinants proposed by the company were weather normalized.

296. The billing determinant study incorporated future changes in billing units beyond September 30, 2011.

297. Atmos has established that the proposed billing determinants are just and reasonable.

298. Atmos established that the test-year data was adjusted for future growth.

299. It is reasonable that rates are designed to balance the fixed and variable elements in the distribution rates to reflect the underlying cost characteristics of the service.

300. Atmos established the fixed and variable elements through a class cost of service study.

301. The fixed cost for residential customers was $21.09 per month, the fixed costs for commercial customers was $53.41 per month and the fixed cost for the industrial and transportation customers was $907.93 per month.

302. Atmos proposed to dampen the effect of a rate design based exclusively upon the results of the class cost of service study.

303. Atmos proposed a customer charge of $18.00 per month for residential customers, a customer charge of $35.00 per month for commercial customers, and a customer charge of $600 per month for industrial and transportation customers.

304. No evidence was presented that the company's calculation or methodology for determining its fixed costs was flawed.

305. The company's proposed rate design is consistent with Commission precedent in GUD Nos. 9762, 9869, and 10000.

306. The proposed customer charges were not modified to reflect changes to the cost of service in updated filings.

307. It is reasonable to reduce (1) the customer charge to $17.70 for residential customers and (2) the customer charge for commercial customers to $34.72 to reflect adjustments made by the company after the case was filed and adjustments reflected in this Final Order.

308. Administrative costs of the Conservation Energy Efficiency (CEE) Program shall not exceed 15 percent of the total CEE program costs.

309. The proposed rates set out below are just and reasonable:

Mid-Tex Rate Jurisdiction, Excluding Dallas (Incorporated and Unincorporated Areas)

Customer Class	Customer Charge	Consumption Charge
Residential	$17.70	$0.04172 per Ccf
Commercial	$34.72	$0.06589 per Ccf
Industrial & Transportation	$600.00	Tier One $0.2473 per MMBtu
		Tier Two $0.1812 per MMBtu
		Tier Three $0.0389 per MMBtu

CONCLUSIONS OF LAW

1. Atmos Energy Corp., Mid-Tex Division, (Atmos Energy, Atmos, or company) is a Gas Utility as defined in TEX. UTIL. CODE ANN. §101.003(7) (Vernon 2007 and Supp. 2012) and §121.001(Vernon 2007) and is therefore subject to the jurisdiction of the Railroad Commission (Commission) of Texas.

2. The Commission has jurisdiction over Atmos and Atmos' Statement of Intent under TEX. UTIL. CODE ANN. §§ 102.001, 103.022, 103.054, & 103.055, 104.001, 104.001 and 104.201 (Vernon 2007 and Supp. 2012).

3. Under TEX. UTIL. CODE ANN. §102.001 (Vernon 2007 and Supp. 2012), the Commission has exclusive original jurisdiction over the rates and services of a gas utility that distributes natural gas in areas outside of a municipality and over the rates and services of a gas utility that transmits, transports, delivers, or sells natural gas to a gas utility that distributes the gas to the public.

4. This proceeding was conducted in accordance with the requirements of the Gas Utility Regulatory Act (GURA), and the Administrative Procedure Act, TEX. GOV'T CODE ANN. §§ 2001.001 *et seq.* (Vernon 2008 and Supp. 2012) (APA).

5. TEX. UTIL. CODE ANN. §104.107 (Vernon 2007 and Supp. 2012) provides the Commission's authority to suspend the operation of the schedule of proposed rates for 150 days from the date the schedule would otherwise go into effect.

6. The proposed rates constitute a major change as defined by TEX. UTIL. CODE ANN. §104.101 (Vernon 2007 and Supp. 2012).

7. In accordance with TEX. UTIL. CODE ANN. §104.103 (Vernon 2007 and Supp. 2012), 16 TEX. ADMIN. CODE ANN. §§ 7.230 and 7.235, adequate notice was properly provided.

8. In accordance with TEX. UTIL. CODE ANN. §104.102 (Vernon 2007 and Supp. 2012), 16 TEX. ADMIN. CODE ANN. §§ 7.205 and 7.210, Atmos filed its Statement of Intent to change gas distribution rates.

9. Atmos has established that the company's books and records conform with 16 TEX. ADMIN. CODE § 7.310 to utilize the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA) prescribed for natural gas companies and Atmos is thus entitled to the presumption that the amounts included therein are reasonable and necessary in accordance with Commission Rule 7.503.

10. In this proceeding, Atmos has the burden of proof under TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 and Supp. 2012) to show that the proposed rate changes are just and reasonable.

11. Atmos failed to meet its burden of proof in accordance with the provisions of TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 and Supp. 2012) on the elements of its requested rate increase identified in this order.

12. The revenue, rates, rate design, and service charges proposed by Atmos are not found to be just and reasonable, not unreasonably preferential, prejudicial, or discriminatory, and are not sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. §104.003 (Vernon 2007 and Supp. 2012).

13. The revenue, rates, rate design, and service charges proposed by Atmos, as amended by the Commission and identified in the schedules attached to this order, are just and reasonable, are not unreasonably preferential, prejudicial, or discriminatory, and are sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. (Vernon 2007 and Supp. 2012).

14. The Commission has assured that the rates, operations, and services established in this docket are just and reasonable to customers and to the utilities in accordance with the stated purpose of the Texas Utilities Code, Subtitle A, expressed under TEX. UTIL. CODE ANN. §101.002 (Vernon 2007).

15. The overall revenues as established by the findings of fact and attached schedules are reasonable; fix an overall level of revenues for Atmos that will permit the company a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public over and above its reasonable and necessary operating expenses, as required by TEX. UTIL. CODE ANN. § 104.051 (Vernon 2007 and Supp. 2012); and otherwise comply with Chapter 104 of the Texas Utilities Code Annotated.

16. The revenue, rates, rate design, and service charges proposed will not yield to Atmos more than a fair return on the adjusted value of the invested capital used and useful in rendering service to the public, as required by TEX. UTIL. CODE ANN. § 104.052 (Vernon 2007 and Supp. 2012).

17. The rates established in this docket comport with the requirements of TEX. UTIL. CODE ANN. §104.053 (Vernon 2007 and Supp. 2012) and are based upon the adjusted value of invested capital used and useful, where the adjusted value is a reasonable balance between the original cost, less depreciation, and current cost, less adjustment for present age and condition.

18. The rates established in this case comply with the affiliate transaction standard set out in TEX. UTIL. CODE ANN. § 104.055 (Vernon 2007 and Supp. 2012). Namely, in establishing a gas utility's rates, the regulatory authority may not allow a gas utility's payment to an affiliate for the cost of a service, property, right or other item or for an interest expense to be included as capital cost or an expense related to gas utility service expect to the extent that the regulatory authority finds the payment is reasonable and necessary for each item or class of items as determined by the regulatory authority. That finding must include (1) a specific finding of reasonableness and necessity to each class of items allowed; and (2) a finding that the price to the gas utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a nonaffiliated person for the same item or class of items.

19. In accordance with TEX. UTIL. CODE ANN. §104.054 (Vernon 2007 and Supp. 2012) and TEX. ADMIN. CODE §7.5252, book depreciation and amortization was calculated on a straight line basis over the useful life expectancy of Atmos' property and facilities.

20. Rate case expenses for GUD Nos. 10170 and 10194 will be considered by the Commission in accordance with TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 and Supp. 2012), and 16 TEX. ADMIN. CODE §7.5530 (2008), in a separate proceeding.

21. Atmos Mid-Tex established that the interim rate adjustments made from 2010, 2011 and 2012 were just and reasonable, in accordance with GURA §104.301 and TEX. ADMIN. CODE §7.7101.

22. Atmos Mid-Tex established that the interim rate adjustment requests made in 2010, 2011 and 2012 were carefully scrutinized to include only appropriate expenses, in accordance with GURA §104.301 and TEX. ADMIN. CODE § 7.7101.

23. It is reasonable for the Commission to allow Atmos to include a Purchased Gas Adjustment Clause in its rates to provide for the recovery of all of its gas costs, in accordance with 16 TEX. ADMIN. CODE § 7.5519.

24. Atmos is required by 16 TEX. ADMIN. CODE §7.315 to file electronic tariffs incorporating rates consistent with this Order within thirty days of the date of this Order.

IT IS THEREFORE ORDERED that Atmos' proposed schedule of rates is hereby **DENIED**.

IT IS FURTHER ORDERED that the rates, rate design, and service charges established in the findings of fact and conclusions of law and shown on the attached Schedules for Atmos are **APPROVED**.

IT IS FURTHER ORDERED that Atmos set up a reserve fund and reimburse ratepayers for any over-recovery of amounts from adjustments related to the Wylie and Cleburne incidents, during the next IRA, RRM, or Statement of Intent proceeding, whichever occurs first.

IT IS FURTHER ORDERED that Atmos set up a reserve fund and reimburse ratepayers for any over-recovery of amounts from adjustments related to the Cancellation Fee during the next IRA, RRM or Statement of Intent proceeding, whichever occurs first.

IT IS FURTHER ORDERED that, in accordance with 16 TEX. ADMIN. CODE §7.315, within 30 days of the date this Order is signed, Atmos shall electronically file tariffs and rate schedules with the Gas Services Division. The tariffs shall incorporate rates, rate design, and service charges consistent with this Order, as stated in the findings of fact and conclusions of law and shown on the attached Schedules.

IT IS FURTHER ORDERED that on or before June 1 of each year, the company posts on its website and also files a copy with the Gas Services Division Director of the Commission, the annual Weather Normalization Report (WNA) in spreadsheet format demonstrating how the company calculated the WNA as set out in the attached tariffs.

IT IS FURTHER ORDERED that on or before March 1 of each year, the company posts on its website and also files a copy with the Gas Services Division Director of the Commission, the annual Conservation and Energy Efficiency (CEE) report in spreadsheet format demonstrating how the company calculated the CEE as set out in the attached tariffs, including: detailed calculations of the CRC, Balancing Adjustments, total cost of the CEE Program, each individual rate program, and detailed tracking of reporting program administrative costs.

IT IS FURTHER ORDERED that administrative costs of the CEE Program shall not exceed 15 percent of the total CEE program costs.

IT IS FURTHER ORDERED that all proposed findings of fact and conclusions of law not specifically adopted in this Order are hereby **DENIED**.

IT IS ALSO ORDERED that all pending motions and requests for relief not previously granted or granted herein are hereby **DENIED**.

This Order will not be final and effective until 20 days after a party is notified of the Commission's order. A party is presumed to have been notified of the Commission's order three days after the date on which the notice is actually mailed. If a timely motion for rehearing is filed by any party at interest, this order shall not become final and effective until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the

Commission. Pursuant to TEX. GOV'T CODE ANN. §2001.146(e), the time allotted for Commission action on a motion for rehearing in this case prior to its being overruled by operation of law, is hereby extended until 90 days from the date the order is served on the parties.

SIGNED this 4th day of December, 2012.

RAILROAD COMMISSION OF TEXAS

B. T. Smitherman

CHAIRMAN BARRY T. SMITHERMAN

Buddy Garcia

COMMISSIONER BUDDY GARCIA

While I join in approving this order, I respectfully dissent on Finding of Fact No. 279, which approves a return on equity of 10.5%.

David Porter

COMMISSIONER DAVID PORTER

ATTEST:

Kathy Way

SECRETARY

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RATE SCHEDULE:	**R – RESIDENTIAL SALES**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**Bills Rendered on or after 12/4/12**	

Application
Applicable to Residential Customers for all natural gas provided at one Point of Delivery and measured through one meter.

Type of Service
Where service of the type desired by Customer is not already available at the Point of Delivery, additional charges and special contract arrangements between Company and Customer may be required prior to service being furnished.

Monthly Rate
Customer's monthly bill will be calculated by adding the following Customer and Ccf charges to the amounts due under the riders listed below:

Charge	**Amount**
Customer Charge per Bill	$17.70 per month
Commodity Charge – All Ccf	$ 0.04172 per Ccf

Gas Cost Recovery: Plus an amount for gas costs and upstream transportation costs calculated in accordance with Part (a) and Part (b), respectively, of Rider GCR.

Weather Normalization Adjustment: Plus or Minus an amount for weather normalization calculated in accordance with Rider WNA.

Franchise Fee Adjustment: Plus an amount for franchise fees calculated in accordance with Rider FF. Rider FF is only applicable to customers inside the corporate limits of any incorporated municipality.

Tax Adjustment: Plus an amount for tax calculated in accordance with Rider TAX.

Surcharges: Plus an amount for surcharges calculated in accordance with the applicable rider(s).

Agreement
An Agreement for Gas Service may be required.

Notice
Service hereunder and the rates for services provided are subject to the orders of regulatory bodies having jurisdiction and to the Company's Tariff for Gas Service.

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RATE SCHEDULE:	**C – COMMERCIAL SALES**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**Bills Rendered on or after 12/04/12**	

Application
Applicable to Commercial Customers for all natural gas provided at one Point of Delivery and measured through one meter and to Industrial Customers with an average annual usage of less than 30,000 Ccf.

Type of Service
Where service of the type desired by Customer is not already available at the Point of Delivery, additional charges and special contract arrangements between Company and Customer may be required prior to service being furnished.

Monthly Rate
Customer's monthly bill will be calculated by adding the following Customer and Ccf charges to the amounts due under the riders listed below:

Charge	Amount
Customer Charge per Bill	$ 34.72 per month
Commodity Charge - All Ccf	$ 0.06589 per Ccf

Gas Cost Recovery: Plus an amount for gas costs and upstream transportation costs calculated in accordance with Part (a) and Part (b), respectively, of Rider GCR.

Weather Normalization Adjustment: Plus or Minus an amount for weather normalization calculated in accordance with Rider WNA.

Franchise Fee Adjustment: Plus an amount for franchise fees calculated in accordance with Rider FF. Rider FF is only applicable to customers inside the corporate limits of any incorporated municipality.

Tax Adjustment: Plus an amount for tax calculated in accordance with Rider TAX.

Surcharges: Plus an amount for surcharges calculated in accordance with the applicable rider(s).

Agreement
An Agreement for Gas Service may be required.

Notice
Service hereunder and the rates for services provided are subject to the orders of regulatory bodies having jurisdiction and to the Company's Tariff for Gas Service.

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RATE SCHEDULE:	**I – INDUSTRIAL SALES**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**Bills Rendered on or after 12/4/12**	

Application
Applicable to Industrial Customers with a maximum daily usage (MDU) of less than 3,500 MMBtu per day for all natural gas provided at one Point of Delivery and measured through one meter. Service for Industrial Customers with an MDU equal to or greater than 3,500 MMBtu per day will be provided at Company's sole option and will require special contract arrangements between Company and Customer.

Type of Service
Where service of the type desired by Customer is not already available at the Point of Delivery, additional charges and special contract arrangements between Company and Customer may be required prior to service being furnished.

Monthly Rate
Customer's monthly bill will be calculated by adding the following Customer and MMBtu charges to the amounts due under the riders listed below:

Charge	Amount
Customer Charge per Meter	$ 600.00 per month
First 0 MMBtu to 1,500 MMBtu	$ 0.2473 per MMBtu
Next 3,500 MMBtu	$ 0.1812 per MMBtu
All MMBtu over 5,000 MMBtu	$ 0.0389 per MMBtu

Gas Cost Recovery: Plus an amount for gas costs and upstream transportation costs calculated in accordance with Part (a) and Part (b), respectively, of Rider GCR.

Franchise Fee Adjustment: Plus an amount for franchise fees calculated in accordance with Rider FF. Rider FF is only applicable to customers inside the corporate limits of any incorporated municipality.

Tax Adjustment: Plus an amount for tax calculated in accordance with Rider TAX.

Surcharges: Plus an amount for surcharges calculated in accordance with the applicable rider(s).

Curtailment Overpull Fee
Upon notification by Company of an event of curtailment or interruption of Customer's deliveries, Customer will, for each MMBtu delivered in excess of the stated level of curtailment or interruption, pay Company 200% of the midpoint price for the Katy point listed in *Platts Gas Daily* published for the applicable Gas Day in the table entitled "Daily Price Survey."

Replacement Index
In the event the "midpoint" or "common" price for the Katy point listed in *Platts Gas Daily* in the table entitled "Daily Price Survey" is no longer published, Company will calculate the applicable imbalance fees utilizing a daily price index recognized as authoritative by the natural gas industry and most closely approximating the applicable index.

Agreement
An Agreement for Gas Service may be required.

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RATE SCHEDULE:	**I – INDUSTRIAL SALES**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**Bills Rendered on or after 12/4/12**	

Notice
Service hereunder and the rates for services provided are subject to the orders of regulatory bodies having jurisdiction and to the Company's Tariff for Gas Service.

Special Conditions
In order to receive service under Rate I, Customer must have the type of meter required by Company. Customer must pay Company all costs associated with the acquisition and installation of the meter.

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RATE SCHEDULE:	**T – TRANSPORTATION**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**Bills Rendered on or after 12/4/12**	

Application
Applicable, in the event that Company has entered into a Transportation Agreement, to a customer directly connected to the Atmos Energy Corp., Mid-Tex Division Distribution System (Customer) for the transportation of all natural gas supplied by Customer or Customer's agent at one Point of Delivery for use in Customer's facility.

Type of Service
Where service of the type desired by Customer is not already available at the Point of Delivery, additional charges and special contract arrangements between Company and Customer may be required prior to service being furnished.

Monthly Rate
Customer's bill will be calculated by adding the following Customer and MMBtu charges to the amounts and quantities due under the riders listed below:

Charge	Amount
Customer Charge per Meter	$ 600.00 per month
First 0 MMBtu to 1,500 MMBtu	$ 0.2473 per MMBtu
Next 3,500 MMBtu	$ 0.1812 per MMBtu
All MMBtu over 5,000 MMBtu	$ 0.0389 per MMBtu

Upstream Transportation Cost Recovery: Plus an amount for upstream transportation costs in accordance with Part (b) of Rider GCR.

Retention Adjustment: Plus a quantity of gas as calculated in accordance with Rider RA.

Franchise Fee Adjustment: Plus an amount for franchise fees calculated in accordance with Rider FF. Rider FF is only applicable to customers inside the corporate limits of any incorporated municipality.

Tax Adjustment: Plus an amount for tax calculated in accordance with Rider TAX.

Surcharges: Plus an amount for surcharges calculated in accordance with the applicable rider(s).

Imbalance Fees
All fees charged to Customer under this Rate Schedule will be charged based on the quantities determined under the applicable Transportation Agreement and quantities will not be aggregated for any Customer with multiple Transportation Agreements for the purposes of such fees.

Monthly Imbalance Fees
Customer shall pay Company the greater of (i) $0.10 per MMBtu, or (ii) 150% of the difference per MMBtu between the highest and lowest "midpoint" price for the Katy point listed in *Platts Gas Daily* in the table entitled "Daily Price Survey" during such month, for the MMBtu of Customer's monthly Cumulative Imbalance, as defined in the applicable Transportation Agreement, at the end of each month that exceeds 10% of Customer's receipt quantities for the month.

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RATE SCHEDULE:	**T – TRANSPORTATION**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**Bills Rendered on or after 12/4/12**	

Curtailment Overpull Fee
Upon notification by Company of an event of curtailment or interruption of Customer's deliveries, Customer will, for each MMBtu delivered in excess of the stated level of curtailment or interruption, pay Company 200% of the midpoint price for the Katy point listed in *Platts Gas Daily* published for the applicable Gas Day in the table entitled "Daily Price Survey."

Replacement Index
In the event the "midpoint" or "common" price for the Katy point listed in *Platts Gas Daily* in the table entitled "Daily Price Survey" is no longer published, Company will calculate the applicable imbalance fees utilizing a daily price index recognized as authoritative by the natural gas industry and most closely approximating the applicable index.

Agreement
A transportation agreement is required.

Notice
Service hereunder and the rates for services provided are subject to the orders of regulatory bodies having jurisdiction and to the Company's Tariff for Gas Service.

Special Conditions
In order to receive service under Rate T, customer must have the type of meter required by Company. Customer must pay Company all costs associated with the acquisition and installation of the meter.

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RIDER:	**WNA – WEATHER NORMALIZATION ADJUSTMENT**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**Bills Rendered on or after 12/4/12**	

Provisions for Adjustment

The Commodity Charge per Ccf (100 cubic feet) for gas service set forth in any Rate Schedules utilized by the cities of the Mid-Tex Division service area for determining normalized winter period revenues shall be adjusted by an amount hereinafter described, which amount is referred to as the "Weather Normalization Adjustment." The Weather Normalization Adjustment shall apply to all temperature sensitive residential and commercial bills based on meters read during the revenue months of November through April. The five regional weather stations are Abilene, Austin, Dallas, Waco, and Wichita Falls

Computation of Weather Normalization Adjustment

The Weather Normalization Adjustment Factor shall be computed to the nearest one-hundredth cent per Ccf by the following formula:

$$WNAF_i = R_i \frac{(HSF_i \times (NDD\text{-}ADD))}{(BL_i + (HSF_i \times ADD)\text{-})}$$

Where

i = any particular Rate Schedule or billing classification within any such particular Rate Schedule that contains more than one billing classification

$WNAF_i$ = Weather Normalization Adjustment Factor for the i^{th} rate schedule or classification expressed in cents per Ccf

R_i = Commodity Charge rate of temperature sensitive sales for the i^{th} schedule or classification.

HSF_i = heat sensitive factor for the i^{th} schedule or classification divided by the average bill count in that class

NDD = billing cycle normal heating degree days calculated as the simple ten-year average of actual heating degree days.

ADD = billing cycle actual heating degree days.

BL_i = base load sales for the i^{th} schedule or classification divided by the average bill count in that class

The Weather Normalization Adjustment for the j^{th} customer in i^{th} rate schedule is computed as:

$WNA_i = WNAF_i \times q_{ij}$

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RIDER:	WNA – WEATHER NORMALIZATION ADJUSTMENT	
APPLICABLE TO:	ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS	
EFFECTIVE DATE:	Bills Rendered on or after 12/4/12	

Where q_{ij} is the relevant sales quantity for the j^{th} customer in i^{th} rate schedule.

Base Use/Heat Use Factors

	Residential		Commercial	
Weather Station	Base use Ccf	Heat use Ccf/HDD	Base use Ccf	Heat use Ccf/HDD
Abilene	9.45	0.1384	90.11	0.6237
Austin	10.54	0.1419	182.64	0.8023
Dallas	12.40	0.1968	168.45	0.9634
Waco	9.25	0.1497	109.69	0.7169
Wichita Falls	10.74	0.1431	99.04	0.5693

Weather Normalization Adjustment (WNA) Report

On or before June 1 of each year, the company posts on its website at (ENTER WEBSITE LINK), in Excel format, a *Weather Normalization Adjustment (WNA) Report* to show how the company calculated its WNAs factor during the preceding winter season. Additionally, on or before June 1 of each year, the company files one hard copy and an Excel version of the *WNA Report* with the Railroad Commission of Texas' Gas Services Division, addressed to the Director of that Division.

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RIDER:	**GCR – GAS COST RECOVERY**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**12/04/12**	

Applicable to Rate R, Rate C, and Rate I for all gas sales made by Company, and applicable to Rate R, Rate C, Rate I, and Rate T for recovery of Pipeline System costs. The total gas cost recovery amount due is determined by adding the gas cost calculated in Section (a) below and the pipeline cost calculated in Section (b) below.

The amount due for gas cost (Section (a)) is determined by multiplying the Gas Cost Recovery Factor (GCRF) by the Customer's monthly volume. For Customers receiving service under Rate R and Rate C, monthly volume will be calculated on a Ccf basis (to calculate on a Mcf basis divide the monthly volume by 10). For Customers receiving service under Rate I, monthly volume will be calculated on an MMBtu basis and the quantities will be adjusted as necessary to recover actual gas costs.

The amount due for pipeline cost (Section (b)) is determined by multiplying the Pipeline Cost Factor (PCF) by the Customer's monthly volume. For Customers receiving service under Rate R and Rate C, monthly volume will be calculated on a Ccf basis. For Customers receiving service under Rate I and Rate T, monthly volume will be calculated on an MMBtu basis and the quantities will be adjusted as necessary to recover actual gas costs.

(a) Gas Cost

Method of Calculation

The monthly gas cost adjustment is calculated by the application of a Gas Cost Recovery Factor (GCRF), as determined with the following formula:

GCRF = Estimated Gas Cost Factor (EGCF) + Reconciliation Factor (RF) + Taxes (TXS)

EGCF = Estimated cost of gas, including lost and unaccounted for gas attributed to residential, commercial, and industrial sales, and any reconciliation balance of unrecovered gas costs, divided by the estimated total residential, commercial, and industrial sales. Lost and unaccounted for gas is limited to 5%.

RF = Calculated by dividing the difference between the Actual Gas Cost Incurred, inclusive of interest over the preceding twelve-month period ended June 30 and the Actual Gas Cost Billed over that same twelve-month period by the estimated total residential, commercial, and industrial sales for the succeeding October through June billing months. The interest rate to be used is the annual interest rate on overcharges and under charges by a utility as published by the Public Utility Commission each December.

Actual Gas Cost Incurred = The sum of the costs booked in Atmos Energy Corp., Mid-Tex Division account numbers 800 through 813 and 858 of the FERC Uniform System of Accounts, including the net impact of injecting and withdrawing gas from storage. Also includes a credit or debit for any out-of-period adjustments or unusual or nonrecurring costs typically considered gas costs and a credit for amounts received as Imbalance Fees or Curtailment Overpull Fees.

Actual Gas Cost Billed = EGCF multiplied by the monthly volumes billed to Residential, Commercial and Industrial Sales customers, less the total amount of gas cost determined to have been uncollectible and written off which remain unpaid for each month of the reconciliation period.

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RIDER:	GCR – GAS COST RECOVERY	
APPLICABLE TO:	ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS	
EFFECTIVE DATE:	12/04/12	

Any amount remaining in the reconciliation balance after the conclusion of the period of amortization will be maintained in the reconciliation balance and included in the collection of the next RF.

Atmos Energy shall file annual reports with the Commission, providing by month the following amounts: Gas Cost Written Off. Margin Written Off, Tax and Other Written Off, Total Written Off, Gas Cost Collected and Margin Collected.

TXS = Any statutorily imposed assessments or taxes applicable to the purchase of gas divided by the estimated total residential, commercial, and industrial sales.

ADJ = Any surcharge or refund ordered by a regulatory authority, inclusive of interest, divided by the estimated total residential, commercial, and industrial sales is to be included as a separate line item surcharge.

(b) Pipeline Cost

Method of Calculation

Each month, a Pipeline Cost Factor (PCF) is calculated separately for each Pipeline Cost Rate Class listed below. The formula for the PCF is:

PCF = PP / S, where:

PP = (P - A) x D, where:

P = Estimated annual cost of pipeline service calculated pursuant to Rate CGS

D = Pipeline service allocation factor for the rate class as approved in the Company's most recent rate case, as follows:

Pipeline Cost Rate Class	Allocation Factor (D)
Rate R - Residential Service	.643027
Rate C - Commercial Service	.305476
Rate I - Industrial Service and Rate T - Transportation Service	.051497

A = Adjustment applied in the current month to correct for the difference between the actual and estimated pipeline cost revenue balance, inclusive of interest, for the most recent 12 months ending June 30, calculated by the formula:

A = R - (C - A2), where:

R = Actual revenue received from the application of the PP component for the most recent 12 months ending June 30.

C = Actual pipeline costs for the most recent 12 months ending June 30.

RIDER:	**GCR – GAS COST RECOVERY**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**12/04/12**	

A2 = The adjustment (A) applied to the PP component for balances from the preceding 12 months ending June 30.

S = Estimated annual Ccf or MMBtu for the rate class for the current and ensuing billing months ending June 30.

The PCF is calculated to the nearest 0.0001 cent.

The Pipeline Cost to be billed is determined by multiplying the Ccf or MMBtu used by the appropriate PCF. The Pipeline Cost is determined to the nearest whole cent.

ATMOS ENERGY CORPORATION

MID-TEX DIVISION

RATE SCHEDULE:	**CEE - CONSERVATION AND ENERGY EFFICIENCY**	
APPLICABLE TO:	**ALL CUSTOMERS IN THE MID-TEX DIVISION EXCEPT THE CITY OF DALLAS CUSTOMERS**	
EFFECTIVE DATE:	**Bills Rendered on and after 12/04/12**	**PAGE:**

I. Purpose

Atmos Energy Corporation's Mid-Tex Division provides a Conservation and Energy Efficiency program which offers assistance to residential and commercial customers to encourage reductions in energy consumption and lower energy utility bills. The proposal is one where Atmos Energy shareholders will fund a half of the allowable expenses incurred annually, with a customer rate component providing the remainder of the funding. The programs offered under Rate Schedule CEE will be consistent with similar conservation and energy efficiency programs offered by other gas utilities and may include, but not limited to residential and commercial customer rebates for high efficiency appliances and equipment, as well as a low income customer weatherization assistance program.

II. Application

Applicable to Rate R Sales Service and Rate C Commercial Sales Service customers only.

The Customer Charges under Rate Schedule R-Residential Sales and Rate Schedule C-Commercial Sales, shall be increased or decreased annually beginning July 1, 2013 by the CEE Cost Recovery Component (CEE) at a rate per bill in accordance with the following formula:

CEE = (CRC per class + BA per class)/Number of Annual Bills per class

Where:

CRC = Cost Recovery-Current. The CRC shall include all expected costs attributable to the Company's CEE program for the twelve month period ending June 30th of each year, including, but not limited to rebates paid, material costs, the costs associated with installation and removal of replaced materials and/or equipment, the cost of educational and customer awareness materials related to conservation/efficiency and the planning, development, implementation and administration of the CEE program. CRC will calculated in a manner that results in non-recurring costs being recovered only once Direct program costs will be identified by class and common administrative costs will be allocated to each class pro-rata based upon the proportion of direct costs. . Administrative costs shall not exceed 15% of total CEE program costs.

BA = Balance Adjustment. The BA shall compute differences between Rider CRC collections by class and expenditures by class, including the pro-rata share of common administrative costs for each class for the twelve month period ending the prior December 31 and collect the over/under recovery during the 12 month period beginning July 1 of the following year.

Class = Rate R Sales Service customers and Rate C Sales Service customers.

III. Administration

A third-party administrator (Program Administrator) may coordinate general program administration. Program administration expenses will be funded from the annual budget.

IV. Program Selection

Program selection will be determined on annual basis and a summary of programs selected for the upcoming twelve-month period will be provided to interested parties on or before March 1st of each calendar year. The portfolio of program offerings will be designed to be impactful and cost effective based on Atmos' knowledge of its customer base and experience administering various conservation and energy efficiency program initiatives. The regulators and Company shall agree prospectively of any changes to the program.

V. Report

The Company will file an annual report with the Director of the Gas Services Division of the Railroad Commission on or before March 1 of each calendar year. The annual report shall also be made available on the Company's website. The annual report will identify the portfolio of program offerings the Company will provide during the twelve-month period commencing July 1 of each year. This annual filing shall include detailed calculations of the CRC and the Balancing Adjustments, as well as data on the total cost of the CEE Program and by each individual rebate program. Detailed tracking and reporting of program administration costs is also required.

RATE SCHEDULE:	**M – MISCELLANEOUS CHARGES**	
APPLICABLE TO:	**Entire Division**	
EFFECTIVE DATE:	**Bills Rendered on or after 12/04/12**	**PAGE: 91**

Application

The service charges on this tariff will be applied in accordance with Atmos Energy's Quality of Service Rules and Commission Rule 7.45.
The service charges listed below are in addition to any other charges made under Company's Tariff for Gas Service and will be applied for the condition described. Other services not covered by these standard conditions will be charged on the basis of an estimate for the job or the Company's cost plus appropriate adders. Business hours are Monday- Friday 8:00 a.m.- 5:00 p.m.and apply to services initiated during these time periods; After hours are Monday-Friday 5:00 p.m.- 8:00 a.m. and all day Saturday and Sunday. The Company may charge an after hours rate in accordance with service charges defined below for services inititated during these time periods.

Applicable Charges:

Charge No.	Name and Description
1	**Connection Charge** The following connection charges apply: <u>Schedule</u> — <u>Charge</u> business hours — $ 65.00 after hours — $ 97.00 For each reconnection of gas service where service has been discontinued at the same premises for any reason, for the initial inauguration of service, and for each inauguration of service when the billable party has changed, with the following exceptions: (a) For a builder who uses gas temporarily during construction or for display purposes. Whenever gas service has been temporarily interrupted because of System outage or service work done by Company; or (c) For any reason deemed necessary for Company operations.
2	**Field Read of Meter** A read for change charge of $19.00 is made when it is necessary for the Company to read the meter at a currently served location because of a change in the billable party.
3	**Returned Check Charges** A returned check handling charge of $20.00 is made for each check returned to Company for any reason.

RATE SCHEDULE:	**M – MISCELLANEOUS CHARGES**	
APPLICABLE TO:	**Entire Division**	
EFFECTIVE DATE:	**Bills Rendered on or after 12/04/12**	**PAGE: 92**

Charge No.	Name and Description
4	**Charge for Installing and Maintaining an Excess Flow Valve** A customer may request the installation of an excess flow valve provided that the service line will serve a single residence and operate continuously throughout the year at a pressure of not less than 10 psig. The customer will pay the actual cost incurred to install the excess flow valve. That cost will include the cost of the excess flow valve, the labor cost required to install the excess flow valve, and other associated costs. The estimated total cost to install an excess flow valve is $50.00. This cost is based on installing the excess flow valve at the same time a service line is installed or replaced. The excess flow valve will be installed on the service line upstream of the customer's meter and as near as practical to the main. A customer requiring maintenance, repair, or replacement of an excess flow valve will be required to pay the actual cost of locating and repairing or replacing the excess flow valve. The cost to perform this service will normally range from $200.00 to $2,000.00, depending on the amount of work required. This cost will be determined on an individual project basis. This tariff is being filed in accordance with the U.S. Department of Transportation rule requiring the installation of an excess flow valve, if requested by a customer, on new or replaced service lines that operate continuously throughout the year at a pressure of not less than 10 psig and that serve a single residence. The rule further states that the customer will bear all costs of installing and maintaining the excess flow valve.
5	**Recovery of Connection Costs Associated with Certain Stand-By Gas Generators** Commercial customers installing stand-by gas generators to provide service in the event of an interruption in electric service in facilities where gas service is not otherwise provided will reimburse the Company for the actual cost of acquiring and installing the regulator, service line, and meter required to provide gas service for the stand-by generators. Gas service provided for the stand-by generators will be billed at the applicable commercial rate.
6	**Charge for Temporary Discontinuance of Service - Residential** Whenever service under this rate schedule has been temporarily disconnected at the request of the customer, a charge of $65.00 plus the appropriate Connection Charge will be made to reestablish such service for that customer at the same address.
7	**Charge for Temporary**

MID-TEX DIVISION
ATMOS ENERGY CORPORATION

RATE SCHEDULE:	M – MISCELLANEOUS CHARGES	
APPLICABLE TO:	Entire Division	
EFFECTIVE DATE:	Bills Rendered on or after 12/04/12	PAGE: 93

Charge No.	Name and Description
	Discontinuance of Service - Non-Residential Whenever service under this rate schedule has been temporarily disconnected at the request of the customer, a charge of $107.00 plus the appropriate Connection Charge will be made to reestablish such service for that customer at the same address.
8	**Charge for Meter Testing** The Company shall, upon request of a customer, make a test of the accuracy of the meter serving that customer. The Company shall 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 (4) years for the same customer at the same location, the test shall be performed without charge. If such a test has been performed for the same customer at the same location within the previous four (4) years, the Company will charge a fee of $15.00. The customer must be properly informed of the result of any test on a meter that serves him.
9	**Charge for Service Calls** A Service Call Charge is made for responding to a service call that is determined to be a customer related problem rather than a Company or Company facilities problem. $26.00 business hours $40.00 after hours
10	**Tampering Charge** No Company Meters, equipment, or other property, whether on Customer's premises or elsewhere, are to be tampered with or interfered with for any reason. A Tampering Charge is made for unauthorized reconnection or other tampering with Company metering facilities, or a theft of gas service by a person on the customer's premises or evidence by whomsoever at customer's premises. An additional cost for the cost of repairs and/or replacement of damaged facilities and the installation of protective facilities or relocation of meter are made at cost plus appropriate charges as detailed in Company's Service Rules and Regulations. $125.00

GUD No. 10170
and consolidated cases

Examiners Schedules
Final Order

Issued Tuesday, December 04, 2012

ATMOS ENERGY CORP., MID-TEX DIVISION
STATEMENT OF INTENT TO CHANGE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Totals may vary due to rounding.

ATMOS ENERGY CORP., MID-TEX DIVISION
TABLE OF CONTENTS
TEST YEAR ENDING SEPTEMBER 30, 2011

ATMOS ENERGY CORP., MID-TEX DIVISION
TABLE OF CONTENTS
TEST YEAR ENDING SEPTEMBER 30, 2011

Decision Summary - GUD No. 10170

Revenue Requirement Requested:	$471,882,773	Revenue Requirement:	$ 447,455,789
		Adjustment to Original Request**:	$16,221,321
		Additional Adjustment:	$8,205,663
		Total Adjustment:	$24,426,984
Increase Requested in Revenues Requested:	$47,709,349	Total Increase in Revenues Recommended:	$ 23,492,932

** Change to request due to depreciation rates update and Sept. 4 corrections filing

	Residential		Commercial		Industrial & Transportation	
Proposed Customer Charge		18.00		35.00		$ 600.00
Recommended		17.70		34.72		$ 600.00
Initial Proposed Usage Charge		0.0709		0.0611		0.19400 0.14210 0.03050
Adjusted Proposed Usage Charge		0.0574		0.0507		0.16380 0.12000 0.02580
	Net Change		Net Change		Net Change	
Recommended Usage Charge	0.0157	0.0417	-0.0152	0.0659	-0.0835 -0.0612 -0.0131	0.24730 0.18120 0.03890

PFD §	ISSUE	Recommendation Adopt = 1, Deny = 0	Schedule Impacted	Element Impacted	Revenue Requirement	Revenue Req Impact**
	SSU Allocation					
	1. Revise SSU Allocations for (IO, IL, KS) (ATM)	0	WP F-2.1		$454,410,363	$1,251,089
			WP F-2.7	Column I		
	(adjustments mutually exclusive)		C	E78		
			C	E119		
	2. Allocation Factor Adjustment (IO,IL,KS) (ACSC)	0	WP F-2.7		$454,244,270	$1,417,182
			WP F-2.7	Column I		
			C	E78		
			C	E119		
	O&M Expense Adjusments					
	1. Base Payroll					
	(a) Payroll Base Labor Adjustment (adjust to December 2011 Level) (ACSC)	0	WP F-2.1	D9, E9 & G9	$455,589,723	$71,729
	(b) Payroll Base Labor Adjustment (adjust O&M Expense Factors) (ACSC)	0	WP F-2.1	D19 & E19	$455,380,362	$281,090
	2. Medical and Dental Benefits					
	(a) Medical/Dental Benefits TY Expense Level (ACSC)	0	WP F-2.2	C9 & D9	$454,368,024	$1,293,428
	(b) Medical/Dental Expense Employee Count (ACSC)	0	WP F-2.2	C11 & D11	$455,610,842	$50,609
	3. Pension Expense & Retiree Med. Benefits Calculated Based Upon TY Level (ACSC)	0	WP F-2.3		$453,735,599	$1,925,853
	Cumulative effect with Pension and OPEB Asset Calculation				$453,404,788	$2,256,664
	4. Remove Mid-Tex SERP (ACSC & ATM)	0	WP F-2.3	G10	$455,612,728	$48,724
	— and corresponding adjustment to ADIT	0	WP B-6	D13		
	5. Adjusted FAS 106 post-test-year adjustment to prior year level of expense. (ACSC)	[redacted]	WP F-2.3	C10 - H10	$455,387,993	$273,459

Decision Summary - GUD No. 10170

Revenue Requirement Requested:	$471,882,773	Revenue Requirement:	$ 447,455,789
		Adjustment to Original Request**:	$16,221,321
		Additional Adjustment:	$8,205,663
		Total Adjustment:	$24,426,984
Increase Requested in Revenues Requested:	$47,709,349	Total Increase in Revenues Recommended:	$ 23,492,932

** Change to request due to depreciation rates update and Sept. 4 corrections filing

	Residential		Commercial		Industrial & Transportation	
Proposed Customer Charge		18.00		35.00	$	600.00
Recommended		17.70		34.72	$	600.00
Initial Proposed Usage Charge		0.0709		0.0611		0.19400 0.14210 0.03050
Adjusted Proposed Usage Charge		0.0574		0.0507		0.16380 0.12000 0.02580
	Net Change		Net Change		Net Change	
Recommended Usage Charge	0.0157	0.0417	-0.0152	0.0659	-0.0835 -0.0612 -0.0131	0.24730 0.18120 0.03890

6. Incentive Compensation:					
(a) Remove all Incentive Compensation (ATM)	[redacted]	WP F-12		$453,559,661	$2,101,791
— and corresponding adjustment to ADIT	0	WP B-6		$455,329,945	$331,505
— O&M - labor expense lag adjustment CWC	0	E	G16	$455,761,493	($100,041)
4(a) is exclusive of 4(b), 4(c) and 4(d).					
(b) Remove SSU LTIP expense (ACSC)	0	WP F-2.7 WP B-1	Column E F16	$454,237,431	$1,424,021
— and corresponding adjustment to adit	0	WP B-6		$455,315,399	$346,053
— and corresponding adjustment to CWC	0			$455,653,191	$8,261
(c) Remove Mid-Tex LTIP expense (ACSC)	[redacted]	F-2	I53	$455,335,613	$325,839
— and corresponding adjustment to adit	0	WP B-1	F17		
(d) Adjust Mid-Tex Short Term Incentive Compensation to 2% of base pay (ACSC)	0	F-2	G53	$455,356,897	$304,554
—and corresponding adjustment to ADIT	0	WP B-1	F18	$455,685,789	($24,337)
7. adjust FAS 106 post-test-year adjustment to prior year level of expense. (ACSC)	[redacted]	WP F-2.3	C10 - H10	$455,387,993	$273,459
8. Injuries and Damages					
(a) Remove expenses related to the Lutrell Incident (ACSC)	0	WP B-2 WP F-2.8	F13	$456,219,042	($557,591)
(b) Adjust recovery Wylie & Cleborne to 36 months (ACSC) Evidentiary Record Insufficient	0	WP F-2.5	E10, E13, E14	$455,322,496	$338,956
9. Property Insurance					
(a) Remove Property Insurance Expense (ACSC).	0	WP F-2.4	C10, D10, E10	$454,972,579	$688,873
(b) Property Insurance Adjust to Remove Ins. Expense for CWIP. (ACSC)	1			$455,649,386	$12,065
(c) Amortization of Cancellation Expense over 36 months (ACSC) Evidentiary Record Insufficient	0			$455,541,786	$119,666
(d) Revenue Sharing of Blueflame Income (ATM)	0	WP J-2	D13	No change to revenue requirement calculation Change to rates will generate a reduction in Revenue recovered	

Decision Summary - GUD No. 10170

Revenue Requirement Requested:	$471,882,773	Revenue Requirement:	$	447,455,789
		Adjustment to Original Request**:		$16,221,321
		Additional Adjustment:		$8,205,663
		Total Adjustment:		$24,426,984
Increase Requested in Revenues Requested:	$47,709,349	Total Increase in Revenues Recommended:	$	23,492,932

** Change to request due to depreciation rates update and Sept. 4 corrections filing

	Residential		Commercial		Industrial & Transportation	
Proposed Customer Charge		18.00		35.00	$	600.00
Recommended		17.70		34.72	$	600.00
Initial Proposed Usage Charge		0.0709		0.0611		0.19400
						0.14210
						0.03050
Adjusted Proposed Usage Charge		0.0574		0.0507		0.16380
						0.12000
						0.02580
	Net Change		Net Change		Net Change	
Recommended Usage Charge	0.0157	0.0417	-0.0152	0.0659	-0.0835	0.24730
					-0.0612	0.18120
					-0.0131	0.03890

Depreciation Expense

1. Mid-Tex and SSU Depreciation Reserve:

Theoretical Reserve: Adopt Company's Theoretical Reserve Depreciation Approach	1				
Book Reserve: Reject Atmos and adopt Dallas Book Reserve Approach Evidentiary Record Insufficient - Adjustment Extrapolated	0	Schedule F-4	**Various Col. F**	**$455,163,504**	**$497,948**

2. Mid-Tex Depreciation:

				Assuming Theoretical Reserve	
(a) Depreciation Service Life Adjustments:					
a. Account 374.02, Land Rights (Atmos 80.R5/Dallas 100R4)	1	Schedule F-4	**F10, F11**	**$455,655,923**	**$5,529**
b. Account 375, Structures (Atmos 54R1.5/Dallas 65R0.5)	0	Schedule F-4	**F12**	**$455,659,513**	**$1,939**
c. Account 376, Mains-Cathodic Protection (Atmos 60R3/Dallas 70R2.5)	0	Schedule F-4	**F13**	**$455,425,186**	**$236,266**
d. Account 376.01, Mains-Steel (Atmos 70R0.5/Dallas 75R0.5)	0	Schedule F-4	**F14**	**$454,833,285**	**$828,167**
e. Account 376.02, Mains-Plastic (Atmos 65R2.5/Dallas 70R2.5)	1	Schedule F-4	**F15**	**$454,366,444**	**$1,295,008**
f. Account 378, Measuring and Reg. Stat. Equip. (Atmos 57R1/Dallas 65R1.5)	0	Schedule F-4	**F16**	**$455,494,880**	**$166,572**
g. Account 379, City Gate Equipment (Atmos: 57R1, Dallas 65R1.5)	0	Schedule F-4	**F17**	**$455,651,932**	**$9,520**
h. Account 385, Ind. Measuring & Regulating Eq. (Atmos 57R1, Dallas: 65R1.5)	0	Schedule F-4	**F22**	**$455,655,209**	**$6,243**
i. Account 380, Distribution Mains (Atmos: 37S0.5, Dallas:41L1)	0	Schedule F-4	**F18**	**$454,814,196**	**$847,256**
j. Account 381, Meters (Atmos 37R1, Dallas: 35R1)	0	Schedule F-4	**F19**	**$455,874,816**	**($213,364)**
k. Account 382, Meter Installations (Atmos N/A, Dallas: 35R1)	0	Schedule F-4	**F20**	**$455,834,886**	**($173,434)**
l. Account 383, House Regulators (Atmos 37R1.5, Dallas: 35R1)	0	Schedule F-4	**F21**	**$455,728,778**	**($67,326)**
m. Account 390, Gen Plant Structures & Improv. (Atmos 45R2.5, Dallas: 55R2.5)	0	Schedule F-4	**F27, F28**	**$455,537,745**	**$123,707**
(b) Depreciation Net Salvage Adjustments:					
a. Account 376.01 Steel Mains (Atmos -105%/Dallas -80%)	0	Schedule F-4		**$453,569,241**	**$2,092,211**
b. Account 376.02 Plastic Mains (Atmos -40%/Dallas -30%)	0	Schedule F-4		**$454,088,943**	**$1,572,509**
c. Account 390 Structures and Improvements (Atmos -5%/Dallas +15%)	0	Schedule F-4		**$455,739,900**	**($78,448)**

3. SSU Depreciation:

(a) Depreciation Service Life Adjustments:					
a. Account 390, Structures and Improvements (Atmos 40R2, Dallas 55R2.5)	0	Schedule F-4		**$455,493,863**	**$167,589**
b. Account 399.08, Application Software (Atmos 12R5, Dallas: 15R5)	0	Schedule F-4		**$454,854,343**	**$807,109**
(b) Depreciation Net Salvage Adjustments:					
a. Account 390, Structures and Improvements (Atmos 0%, Dallas 15%)	0	Schedule F-4		**$455,576,046**	**$85,406**

Decision Summary - GUD No. 10170

Revenue Requirement Requested:	$471,882,773	Revenue Requirement:	$	447,455,789
		Adjustment to Original Request**:		$16,221,321
		Additional Adjustment:		$8,205,663
		Total Adjustment:		$24,426,984
Increase Requested in Revenues Requested:	$47,709,349	Total Increase in Revenues Recommended:	$	23,492,932

** Change to request due to depreciation rates update and Sept. 4 corrections filing

	Residential		Commercial		Industrial & Transportation	
Proposed Customer Charge		18.00		35.00	$	600.00
Recommended		17.70		34.72	$	600.00
Initial Proposed Usage Charge		0.0709		0.0611		0.19400 0.14210 0.03050
Adjusted Proposed Usage Charge		0.0574		0.0507		0.16380 0.12000 0.02580
	Net Change		Net Change		Net Change	
Recommended Usage Charge	-0.0157	0.0417	-0.0152	0.0659	-0.0835 -0.0612 -0.0131	0.24730 0.18120 0.03890

RATE BASE

1. Plant in Service - Adjust all Plant in Service to December 31, 2011 (ACSC)					
(a) Remove plant from Jan. 2012 to March 2012	0	C			
(b) Remove Accumulated Depreciation from Jan. 2012 to March 2012 (Adjustment Required if Plant in Service Adjusted to December 31, 2011)	0	D		$445,866,863	$9,794,588
(c) ADIT Adjustment to remove Jan.-March 2012 (Adjustment Required if Plant in Service Adjusted to December 31, 2011)	0	WP B-6			
2. Pension and OPEB Asset (and amortization expense)					
(a) Disallow (ATM/ACSC)	[redacted]	WP B-7 WP F 2.8	E8 E15	$455,221,681	$439,771
(b) Use Updated 2011 RRM Amount for baseline not 9869 (ATM/ACSC)	0	WP B-7 WP_F 2.8	E8 E15	$455,454,769	$206,683
(c) Calculated Pension and OPEB Overinflated					
Same as O&M Expense Adjustment Item 3					
(d) Revise Pension/OPEB Regulatory Asset (ATM Primary) Insufficient Evidentiary Basis - All elements not explained	[redacted]	WP B-7 WP F 2.8	E8 E15	$455,506,508	$154,944
(e) Additional ATM Alternative					
(f) Allow company update	1			$455,657,285	$4,167
3. Accumulated Deferred Income Taxes					
(a) Adjustment to disallow NOL carryforward (ATM & ACSC)	[redacted]	WP B-6	D89	$446,843,598	$8,817,854
(b) Exclude ADIT related to treasury lock (ATM)	0	WP B-6	D91	$455,902,690	($241,239)
(c) AMT Tax Credit (ATM)	0	WP B-6	D93	$455,201,448	$460,004
(d) Restore CWIP related balances (ATM)	[redacted]	WP B-6	D19, D44, D72	$454,994,457	$666,994
(e) Adjustment to remove Allowance for Doubtful Accounts (ATM)	1	WP B-6	D28	$455,492,996	$168,456
(f) Adjustment to include State NOL - Mid-Tex only (ATM)	N/A	F-6	No adjustment req.		
(g) Adjustment for Intra Period Tax Allocation (ATM)	N/A		No adjustment req.		

Decision Summary - GUD No. 10170

Revenue Requirement Requested:	$471,882,773	Revenue Requirement:	$	447,455,789
		Adjustment to Original Request**:		$16,221,321
		Additional Adjustment:		$8,205,663
		Total Adjustment:		$24,426,984
Increase Requested in Revenues Requested:	$47,709,349	Total Increase in Revenues Recommended:	$	23,492,932

** Change to request due to depreciation rates update and Sept. 4 corrections filing

	Residential		Commercial		Industrial & Transportation	
Proposed Customer Charge		18.00		35.00	$	600.00
Recommended		17.70		34.72	$	600.00
Initial Proposed Usage Charge		0.0709		0.0611		0.19400 0.14210 0.03050
Adjusted Proposed Usage Charge		0.0574		0.0507		0.16380 0.12000 0.02580
	Net Change		Net Change		Net Change	
Recommended Usage Charge	0.0157	0.0417	-0.0152	0.0659	-0.0835 -0.0612 -0.0131	0.24730 0.18120 0.03890

4. FAS 106 Liability:

(a) FAS 106 Adjustment for unfunded liability Reserve (ACSC/ATM)	0	WP B-1	F15	$447,635,654	$8,025,798
OR					
(b) Remove FAS106 ADIT Adjustment: Unfunded liability Reserve (ACSC/ATM)	0	WP B-6	F15	$452,609,250	$3,052,202

5. Cash Working Capital Analysis

(a) Billing Lag Adjustment (ACSC)	0	E	F11	$455,426,891	$234,561
(b) O&M - non labor expense lag adjustment (ATM)	0	E	G17	$455,648,072	$13,379
(c) Other O&M - Non-Labor					
1. Pension Contribution (ATM)	0	E	Row 8a	$455,488,912	$172,540
2. OPEB/FAS 106 Contribution (ATM)	0	E	Row 8b	$455,612,420	$49,032
3. SSU LTIP Costs (ATM) adjustment not made if previously excluded from CWC (See Item 6(b))	0	E	Row 8c		
4. Uncollectibles (ATM)	0	E	Row 8d	$455,656,711	$4,741
(d) Taxes other than income - payroll tax expense lag adjustment (ATM)	0	E	G26	$455,665,961	($4,509)
(e) Allocated taxes SSU - payroll tax expense lag adjustment (ATM)	0	E	G32		

Interim Rate Adjustments

(b) RRC Staff - Removal of Segway projects 080.278652 and 080.27929

Decision Summary - GUD No. 10170

Revenue Requirement Requested:	$471,882,773	Revenue Requirement:	$	447,455,789
		Adjustment to Original Request**:		$16,221,321
		Additional Adjustment:		$8,205,663
		Total Adjustment:		$24,426,984
Increase Requested in Revenues Requested:	$47,709,349	Total Increase in Revenues Recommended:	$	23,492,932

** Change to request due to depreciation rates update and Sept. 4 corrections filing

	Residential		Commercial		Industrial & Transportation	
Proposed Customer Charge		18.00		35.00	$	600.00
Recommended		17.70		34.72	$	600.00
Initial Proposed Usage Charge		0.0709		0.0611		0.19400 0.14210 0.03050
Adjusted Proposed Usage Charge		0.0574		0.0507		0.16380 0.12000 0.02580
	Net Change		Net Change		Net Change	
Recommended Usage Charge	0.0157	0.0417	-0.0152	0.0659	-0.0835 -0.0612 -0.0131	0.24730 0.18120 0.03890

RATE OF RETURN

a. Capital Structure

Long-Term Debt — 48.31% G

- Atmos - 48.3099893151376%
- ACSC - 58.21%
- ATM - 46.54% LTD **AND** 3.67% STD
- Staff - Actual of 48.31%
- State Agencies -

Short-Term Debt — 0.00%

- ATM - 3.67%
- Atmos and All Other Parties (except ATM) - 0%

Cost of Debt — 6.50%

- Atmos - 6.50163361152495%
- ACSC - 6.50%
- ATM - 6.5% Long-term, 2.02% Short-term
- RRC Staff - Actual at 6.5%
- State Agencies -

Common Equity — 51.69%

- Atmos - 51.6900106848624%
- ACSC - 41.79%
- ATM - 49.79%
- Staff - Actual of 51.69%
- State Agencies -

b. Return on Equity — 10.50%

- Atmos - 11.05%
- ACSC - 9%
- ATM - 9.1% - 9.75%
- RRC Staff - 10.10%
- State Agencies - no greater than 10.00%

The net effect of the Examiners ROE recommendation is a reduction totaling $7,949,733

Resulting Rate of Return	8.57%

Decision Summary - GUD No. 10170

Revenue Requirement Requested:	$471,882,773	Revenue Requirement:	$	447,455,789
		Adjustment to Original Request**:		$16,221,321
		Additional Adjustment:		$8,205,663
		Total Adjustment:		$24,426,984
Increase Requested in Revenues Requested:	$47,709,349	Total Increase in Revenues Recommended:	$	23,492,932

** Change to request due to depreciation rates update and Sept. 4 corrections filing

	Residential		Commercial		Industrial & Transportation	
Proposed Customer Charge		18.00		35.00	$	600.00
Recommended		17.70		34.72	$	600.00
Initial Proposed Usage Charge		0.0709		0.0611		0.19400 0.14210 0.03050
Adjusted Proposed Usage Charge		0.0574		0.0507		0.16380 0.12000 0.02580
	Net Change		Net Change		Net Change	
Recommended Usage Charge	0.0157	0.0417	-0.0152	0.0659	-0.0835 -0.0612 -0.0131	0.24730 0.18120 0.03890

CLASS ALLOCATION

ACSC - Minimum System Study	1	Plt- CCS3	G73

RATE DESIGN
BILLING DETERMINANTS

Billing Unit Adjustment Commercial & Residential (ACSC)	[redacted]	WP J-1	C21
Increase calculated residential volumes			C49
-- from 766,043,261 Ccf to 777,726,790 Ccf		1	C14
Increase calculated commercial volumes		1	C15
---from 502,902,414 Ccf to 510,519,363		WP J-1.1	F10-F14

CUSTOMER CHARGE

ACSC - Customer Charge Adjustment	0	Rate Design	C19 and D19
Examiners' Recommendation	1		
Alternative based upon customer cost calculation	0		
ATM Customer Charge Adjustment	0		

Residential Rates	
% Change Environs	% Change Municipalities
-6.14%	80.96%
-6.07%	48.00%
-6.02%	26.05%
-5.96%	10.39%
-5.94%	5.31%
-5.90%	-1.36%
-5.85%	-10.48%
-5.80%	-17.79%
-5.75%	-23.76%
-5.71%	-28.73%

REVENUE ADJUSTMENTS

ATM - Revenue Credit Treasury Lock Gain (To be taken up only if Commission opts to make an adjustment and determines adjustment is not made to Cost of Debt)	0	WP J-2	D11

Decision Summary - GUD No. 10170

Revenue Requirement Requested:	$471,882,773	Revenue Requirement:	$	447,455,789
		Adjustment to Original Request**:		$16,221,321
		Additional Adjustment:		$8,205,663
		Total Adjustment:		$24,426,984
Increase Requested in Revenues Requested:	$47,709,349	Total Increase in Revenues Recommended:	$	23,492,932

** Change to request due to depreciation rates update and Sept. 4 corrections filing

	Residential		Commercial		Industrial & Transportation	
Proposed Customer Charge		18.00		35.00	$	600.00
Recommended		17.70		34.72	$	600.00
Initial Proposed Usage Charge		0.0709		0.0611		0.19400 0.14210 0.03050
Adjusted Proposed Usage Charge		0.0574		0.0507		0.16380 0.12000 0.02580
	Net Change		Net Change		Net Change	
Recommended Usage Charge	0.0157	0.0417	-0.0152	0.0659	-0.0835 -0.0612 -0.0131	0.24730 0.18120 0.03890

NON COS ITEMS:

Staff Recommendation for GRIP Audit No

TARIFFS:

CEE Tariff Changes:

ACSC - add formal review	Yes
ACSC - Modify reconciliation requirements	
ACSC - Severe CEE into another docket	No
RRC Staff - Net with grants, tax credits, other govt. funding	No
RRC Staff - Allocate uniformly to residential and commercial customers	Yes
RRC Staff - 10% ($200,000 administrative cost cap)	15%
Examiners - Approve revised CEE maintain funding as previously approved	0

WNA Tariff Changes:

RRC Staff - Modify calculation language	
RRC Staff - Change winter season to Nov., Dec., Jan., Feb., and March v. Nov.-April	No
RRC Staff - Clarify Provision for Adjustment Section	Yes
RRC Staff - Annual reporting and publish online	Yes

Miscellaneous Charges Rider:

RRC Staff - Clarify compliance with RRC Rule 7.45	Yes
RRC Staff - Additional language regarding restoration or disconnection fees after natural disaster	No

Residential
Commercial
Industrial
Transportation
Gas Cost Adjustment

RATE COMPARISON

Residential Bill
(excluding gas cost)

	Customer Charge	Volumetric Charge	Ccf 20.00	30.00	40.00	44.20	50.00	60.00	70.00	80.00	90.00
Current - Municipallities	$7.50	$0.25116	$ 12.52	$ 15.03	$ 17.55	$ 18.60	$ 20.06	$ 22.57	$ 25.08	$ 27.59	$ 30.10
Current - Environs	$18.87	$0.04315	$ 19.73	$ 20.16	$ 20.60	$ 20.78	$ 21.03	$ 21.46	$ 21.89	$ 22.32	$ 22.75
SOI Requested	$18.00	$0.07094	$ 19.42	$ 20.13	$ 20.84	$ 21.14	$ 21.55	$ 22.26	$ 22.97	$ 23.68	$ 24.38
Sept 4th Update	$18.00	$0.05738	$ 19.15	$ 19.72	$ 20.30	$ 20.54	$ 20.87	$ 21.44	$ 22.02	$ 22.59	$ 23.16
Recommended	$17.70	$0.04172	$ 18.53	$ 18.95	$ 19.37	$ 19.54	$ 19.79	$ 20.20	$ 20.62	$ 21.04	$ 21.45

Commercial
(excluding gas cost)

	Customer Charge	Volumetric Charge	Ccf 100	200	300	343	400	500	600	700	800
Current - Municipallities	$16.75	$0.10217	$ 26.97	$ 37.18	$ 47.40	$ 51.79	$ 57.62	$ 67.84	$ 78.05	$ 88.27	$ 98.49
Current - Environs	$38.04	$0.05748	$ 43.79	$ 49.54	$ 55.28	$ 57.76	$ 61.03	$ 66.78	$ 72.53	$ 78.28	$ 84.02
SOI Requested	$35.00	$0.06105	$ 41.11	$ 47.21	$ 53.32	$ 55.94	$ 59.42	$ 65.53	$ 71.63	$ 77.74	$ 83.84
Sept 4th Update	$35.00	$0.05072	$ 40.07	$ 45.14	$ 50.22	$ 52.40	$ 55.29	$ 60.36	$ 65.43	$ 70.50	$ 75.58
Recommended	$34.72	$0.06589	$ 41.31	$ 47.90	$ 54.49	$ 57.32	$ 61.08	$ 67.67	$ 74.25	$ 80.84	$ 87.43

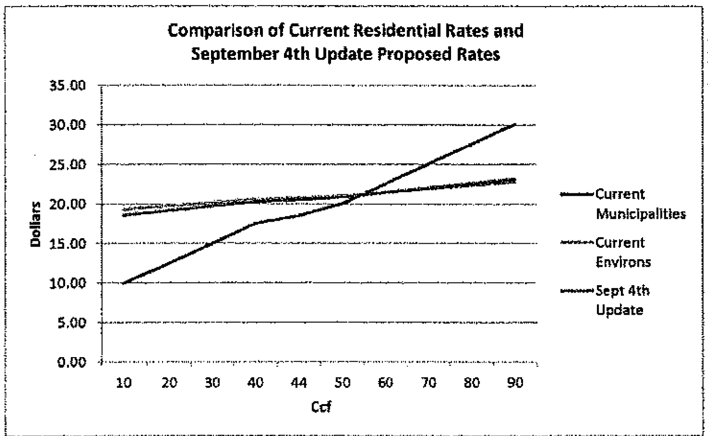
Atmos Mid-Tex
COMPARISON OF CURRENT RATES TO PROPOSED CHANGE
(WITHOUT GAS COSTS)

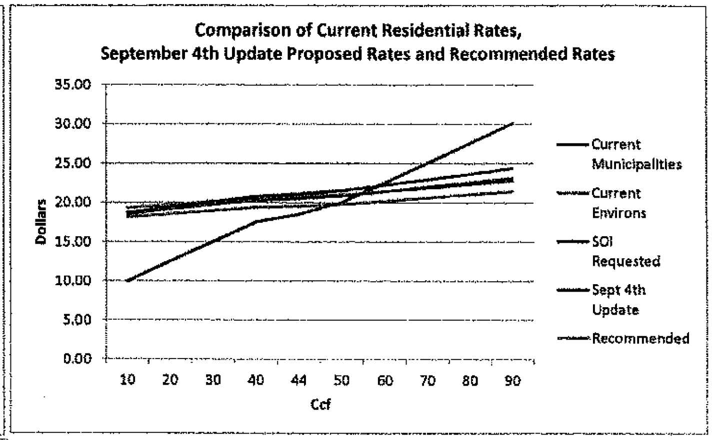
Residential

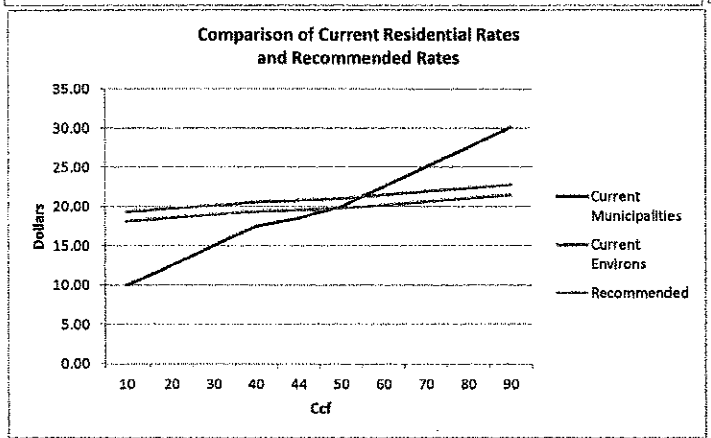
Ccf	Current Municipalities	Current Environs	SOI Requested	Sept 4th Update	Recommended	Change Municipalities - SOI	Change Environs - SOI	% Change Municipalities - SOI	% Change Environs - SOI	Change Municipalities Sept 4 Update	Change Environs - Sept 4 Update	% Change Municipalities Sept 4 Update	% Change Environs Sept 4 Update	Change Municipalities Recommended	Change Environs - Recommended	% Change Municipalities Recommended	% Change Environs Recommended
10	10.01	19.30	18.71	18.57	18.12	8.70	-0.59	86.88%	-3.07%	8.56	-0.73	85.52%	-3.77%	8.11	-1.18	80.96%	-6.14%
20	12.52	19.73	19.42	19.15	18.53	6.90	-0.31	55.06%	-1.59%	6.62	-0.59	52.90%	-2.97%	6.01	-1.20	48.00%	-6.07%
30	15.03	20.16	20.13	19.72	18.95	5.09	-0.04	33.88%	-0.18%	4.69	-0.44	31.17%	-2.20%	3.92	-1.21	26.05%	-6.02%
40	17.55	20.60	20.84	20.30	19.37	3.29	0.24	18.76%	1.17%	2.75	-0.30	15.67%	-1.46%	1.82	-1.23	10.39%	-5.96%
44	18.55	20.77	21.12	20.52	19.54	2.57	0.35	13.86%	1.70%	1.97	-0.24	10.64%	-1.17%	0.98	-1.23	5.31%	-5.94%
50	20.06	21.03	21.55	20.87	19.79	1.49	0.52	7.42%	2.47%	0.81	-0.16	4.04%	-0.75%	-0.27	-1.24	-1.36%	-5.90%
60	22.57	21.46	22.26	21.44	20.20	-0.31	0.80	-1.39%	3.72%	-1.13	-0.02	-4.99%	-0.08%	-2.37	-1.26	-10.48%	-5.85%
70	25.08	21.89	22.97	22.02	20.62	-2.12	1.08	-8.43%	4.91%	-3.06	0.13	-12.22%	0.58%	-4.46	-1.27	-17.79%	-5.80%
80	27.59	22.32	23.68	22.59	21.04	-3.92	1.35	-14.20%	6.06%	-5.00	0.27	-18.13%	1.20%	-6.56	-1.28	-23.76%	-5.75%
90	30.10	22.75	24.38	23.16	21.45	-5.72	1.63	-19.00%	7.17%	-6.94	0.41	-23.05%	1.80%	-8.65	-1.30	-28.73%	-5.71%

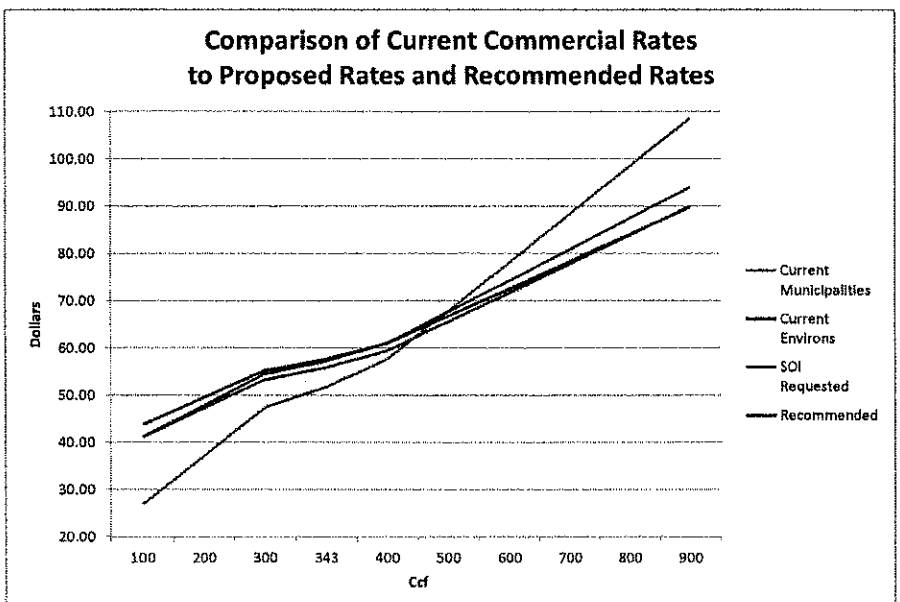
Commercial

Ccf	Current Municipalities	Current Environs	SOI Requested	Sept 4th Update	Recommended	Change Municipalities - SOI	Change Environs - SOI	% Change Municipalities - SOI	% Change Environs - SOI	Change Municipalities Sept 4th Update	Change Environs - Sept 4th Update	% Change Municipalities Sept 4th Update	% Change Environs Sept 4th Update	Change Municipalities Recommended	Change Environs - Recommended	% Change Municipalities Recommended	% Change Environs Recommended
100	26.97	43.79	41.11	41.31	41.31	14.14	-2.68	52.43%	-6.13%	14.34	-2.48	53.18%	-5.66%	14.34	-2.48	53.18%	-5.66%
200	37.18	49.54	47.21	47.90	47.90	10.03	-2.33	26.96%	-4.70%	10.71	-1.64	28.81%	-3.31%	10.71	-1.64	28.81%	-3.31%
300	47.40	55.28	53.32	54.49	54.49	5.91	-1.97	12.48%	-3.56%	7.09	-0.80	14.95%	-1.44%	7.09	-0.80	14.95%	-1.44%
343	51.79	57.76	55.94	57.32	57.32	4.15	-1.82	8.00%	-3.14%	5.53	-0.44	10.67%	-0.75%	5.53	-0.44	10.67%	-0.75%
400	57.62	61.03	59.42	61.08	61.08	1.80	-1.61	3.13%	-2.64%	3.46	0.04	6.00%	0.07%	3.46	0.04	6.00%	0.07%
500	67.84	66.78	65.53	67.67	67.67	-2.31	-1.26	-3.41%	-1.88%	-0.17	0.88	-0.25%	1.33%	-0.17	0.88	-0.25%	1.33%
600	78.05	72.53	71.63	74.25	74.25	-6.42	-0.90	-8.23%	-1.24%	-3.80	1.73	-4.87%	2.38%	-3.80	1.73	-4.87%	2.38%
700	88.27	78.28	77.74	80.84	80.84	-10.53	-0.54	-11.93%	-0.69%	-7.43	2.57	-8.41%	3.28%	-7.43	2.57	-8.41%	3.28%
800	98.49	84.02	83.84	87.43	87.43	-14.65	-0.18	-14.87%	-0.22%	-11.05	3.41	-11.22%	4.06%	-11.05	3.41	-11.22%	4.06%
900	108.70	89.77	89.95	94.02	94.02	-18.76	0.17	-17.26%	0.19%	-14.68	4.25	-13.51%	4.73%	-14.68	4.25	-13.51%	4.73%


Comparison of Current Residential Rates and
September 4th Update Proposed Rates
Dollars
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
10 20 30 40 44 50 60 70 80 90
Ccf
Current Municipalities
Current Environs
Sept 4th Update


Comparison of Current Residential Rates,
September 4th Update Proposed Rates and Recommended Rates
Dollars
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
10 20 30 40 44 50 60 70 80 90
Ccf
Current Municipalities
Current Environs
SOI Requested
Sept 4th Update
Recommended


Comparison of Current Residential Rates
and Recommended Rates
Dollars
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
10 20 30 40 44 50 60 70 80 90
Ccf
Current Municipalities
Current Environs
Recommended


Comparison of Current Commercial Rates
to Proposed Rates and Recommended Rates
Dollars
110.00
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
100 200 300 343 400 500 600 700 800 900
Ccf
Current Municipalities
Current Environs
SOI Requested
Recommended

Section 104.059 Baseline
Pension and OPEB Expense

	Pension Account Plan (FAS 87)	Post Retirement Medical Plans (FAS 106)	SERP		Source
SSU Allocated to Mid-Tex	$2,756,682	$1,971,341	$143,390	WP_F-2.3	Atmos Ex. 7, p. 20, lns. 14 - 23
Mid-Tex Direct	$8,087,526	$7,092,975		WP_F-2.4	Atmos Ex. 7, p. 20, lns. 14 - 24
TOTAL	$10,844,208	$9,064,316	$143,390		

COD Mid-Tex Individual Adjustments Using Theoretical Reserve				
Account	Company Proposed	ASL	NS	ASL+NS
374.02	1.150%	0.980%	1.150%	0.980%
375	1.170%	1.580%	1.710%	1.580%
376	1.185%	1.680%	1.850%	1.680%
376.01	3.970%	3.780%	3.490%	3.320%
376.02	2.350%	2.210%	2.180%	2.050%
378	3.090%	2.670%	3.090%	2.670%
379	1.880%	1.710%	1.880%	1.710%
380	3.670%	3.560%	3.670%	3.560%
381	3.310%	3.440%	3.310%	3.440%
382	3.660%	3.810%	3.660%	3.810%
383	3.500%	3.640%	3.500%	3.640%
385	2.800%	2.320%	2.800%	2.320%
390	2.540%	2.130%	2.800%	1.730%

Link

COD Mid-Tex Individual Adjustments Using Book Reserve				
Account	Company Proposed	ASL	NS	ASL+NS
374.02	1.150%	0.81%	1.120%	0.810%
375	1.170%	0.640%	0.900%	0.650%
376	1.185%	0.940%	1.090%	0.950%
376.01	3.970%	4.690%	4.270%	3.990%
376.02	2.350%	2.320%	2.330%	2.130%
378	3.090%	2.480%	3.010%	2.510%
379	1.880%	1.530%	1.840%	1.570%
380	3.670%	2.410%	2.620%	2.460%
381	3.310%	3.420%	3.270%	3.490%
382	3.660%	3.790%	3.620%	3.850%
383	3.500%	4.060%	3.870%	4.130%
385	2.800%	2.250%	2.760%	2.240%
390	2.540%	1.530%	1.280%	0.980%

COD SSU Individual Adjustments Using Theoretical Reserve				
Account	Company Proposed	ASL	NS	ASL&NS
390	3.34%	2.30%	2.81%	1.94%
399.08	11.11%	5.57%	6.57%	5.57%

COD SSU Individual Adjustments Using BookReserve				
Account	Company Proposed	ASL	NS	ASL&NS
390	3.34%	2.30%	2.88%	1.94%
399.08	11.11%	4.64%	7.08%	4.67%

COD Global Adjustment to Mid-Tex Company Book Only			
Account	Discription	Company Proposed	Book Only (See Note 1)
374	Land	0.00%	0.00%
374.02	Land Rights	1.15%	1.12%
374	Land & Land Rights	1.15%	1.12%
375	Structures & Improvements	1.71%	0.90%
376	Mains-Cathodic Protection	1.85%	1.09%
376.01	Mains-Steel	3.97%	4.94%
376.02	Mains-Plastic	2.35%	2.56%
378	M&R Station Equipment - General	3.09%	3.01%
379	M&R Station Equipment - City Gate	1.88%	1.84%
380	Services	3.67%	2.62%
381	Meters	3.31%	3.27%
382	Meter Installations	3.66%	3.62%
383	House Regulators	3.50%	3.87%
385	Industrial M&R Station Equipment	2.80%	2.76%
389	Land	0.00%	0.00%
390	Structures & Improvements	2.54%	2.07%
390.01	Air Conditioning Equipment	2.75%	2.96%
391	Office Furniture & Equipment	4.00%	4.70%
392	Transportation Equipment	9.04%	20.11%
393	Stores Equipment	4.00%	4.08%
394	Tools, Shop, and Garage Equipment	5.00%	5.49%
395	Laboratory Equipment	10.00%	41.44%
396	Power Oper. Tool & Work Equip.	7.24%	16.65%
397	Radio Communication Equipment	6.67%	16.56%
398	Miscellaneous Equipment	2.50%	1.20%
399	Non-Mainframe Computer Equip.	14.29%	19.69%
399.01	Other Tangible Property-Servers Hardware	14.29%	19.69%
399.02	Other Tangible Property-Servers Software	14.29%	32.76%
399.03	Other Tangible Property-Network-Hardware	11.11%	19.86%
399.06	Other Tangible Property-PC Hardware	14.29%	19.09%
399.07	Other Tangible Property-PC Software	14.29%	32.76%
399.08	Other Tangible Property-Application Software	14.29%	20.42%

COD Global Adjustment to Mid-Tex Company Book Only			
Account	Discription	Company Proposed	Book Only (See Note 1)
390	Structures & Improvements	3.34%	3.59%
390.09	Improvements to Leased Premises	4.06%	2.29%
390.10	CKV-Structures & Improvements	3.34%	2.29%
391	Office Furniture & Equipment	4.03%	3.48%
391.02	Remittance Processing Equipment	4.03%	4.03%
391.03	Office Furniture & Equipment	4.03%	4.03%
392	Transportation Equipment	28.96%	28.96%
393	Stores Equipment	10.00%	10.00%
394	Tools & Work Equipment	8.88%	9.76%
395	Laboratory Equipment	10.00%	10.00%
397	Communication Equipment - Telephone	5.54%	6.02%
397.10	CKV-Communication Equipment	5.54%	5.54%
398	Miscellaneous Equipment	1.72%	21.29%
399	Other Tangible Property	13.84%	15.33%
399.01	Other Tangible Property-Servers Hardware	8.62%	8.85%
399.02	Other Tangible Property-Servers Software	8.78%	9.57%
399.03	Other Tangible Property-Network-Hardware	8.72%	9.81%
399.04	Other Tangible Property-CPU	26.26%	0.00%
399.05	Other Tangible Property-MF Hardware	15.76%	0.00%
399.06	Other Tangible Property-PC Hardware	8.78%	7.31%
399.07	Other Tangible Property-PC Software	6.64%	2.25%
399.08	Other Tangible Property-Application Software	6.57%	4.67%
399.09	Other Tangible Property-System Software	6.21%	0.00%
399.10	CKV-Other Tangible Equipment	13.84%	13.84%
399.16	CKV-PC Hardware	8.78%	8.78%
399.17	CKV-PC Software	6.64%	6.64%
399.24	Other Tangible Property-GenStartupCost	15.89%	41.00%

Note 1: Examiners have extrapolated the book only reserve. It does not appear that this information is in evidence.

ATMOS ENERGY CORP., MID-TEX DIVISION
REVENUE REQUIREMENTS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description (a)	Current Revenues (b) Municipalities	Current Revenues (b) Environs	Current Revenues (b) Total	Proposed Revenues[1] (c)	Proposed Change (d)	Percent Change (e)	Line No.
1								1
2	Residential (Base Revenue)	$ 313,137,765	$ 11,005,954	$ 324,143,720	$ 338,433,621	$ 14,289,902	4.41%	2
3	Residential (Rider GCR)	440,225,416	11,980,511	452,205,927	452,205,927	$ -	0.00%	3
4	Residential (Rider FF & Rider TAX)	50,789,268	1,549,672	52,338,940	53,302,318	$ 963,378	1.84%	4
5	Total Residential	$ 804,152,448	$ 24,536,137	$ 828,688,586	$ 843,941,866	$ 15,253,280	1.84%	5
6								6
7	Commercial (Base Revenue)	$ 74,846,592	$ 1,182,221	$ 76,028,813	$ 84,225,991	$ 8,197,178	10.78%	7
8	Commercial (Rider GCR)	274,295,057	4,116,074	278,411,131	278,411,131	$ -	0.00%	8
9	Commercial (Rider FF & Rider TAX)	23,537,982	371,005	23,908,986	24,447,802	$ 538,816	2.25%	9
10	Total Commercial	$ 372,679,631	$ 5,669,300	$ 378,348,930	$ 387,084,924	$ 8,735,994	2.31%	10
11								11
12	Industrial/Transportation (Base Revenue)	$ 10,079,821	$ 404,315	$ 10,484,136	$ 11,489,989	$ 1,005,852	9.59%	12
13	Industrial/Transportation (Rider GCR)	14,730,343	964,414	15,694,758	15,694,758	$ -	0.00%	13
14	Industrial/Transportation (Rider FF & Rider TAX)	1,672,620	92,275	1,764,895	1,832,706	$ 67,811	3.84%	14
15	Total Industrial/Transportation	$ 26,482,784	$ 1,461,004	$ 27,943,789	$ 29,017,452	$ 1,073,664	3.84%	15
16								16
17	Other Revenue (Base Revenue)			$ 13,310,366	$ 13,310,366	$ 13,310,366	0.00%	17
18	Other Revenue (Rider GCR)				-	-	0.00%	18
19	Other Revenue (Rider FF & Rider TAX)			897,341	897,341	897,341.06	0.00%	19
20	Total Other Revenue			$ 14,207,707	$ 14,207,707	$ 14,207,707	0.00%	20
21								21
22	Base Revenue[2]			$ 423,967,034	$ 447,459,966	$ 23,492,932	5.54%	22
23	Rider GCR			746,311,816	746,311,816	$ 0	0.00%	23
24	Rider FF & Rider TAX			78,910,162	80,480,167	$ 1,570,005	1.99%	24
25	Total Operating Revenues			$ 1,249,189,011	$ 1,274,251,949	$ 25,062,938	2.01%	25
26								26
27								

Line No.	Description (a)	Reference (b)	(c)	Base Revenue (d)	Rider GCR (e)	Rider FF & Rider TAX (f)	Total (g)
1							
2	Rider GCR Part A	Schedule H		$ -	$ 588,090,591	$ -	$ 588,090,591
3	Rider GCR Part B	Schedule I			158,221,225		$ 158,221,225
4	Total Rider GCR			$ -	$ 746,311,816	$ -	$ 746,311,816
5							
6	Operation and Maintenance Expenses	Schedule F-1		$ 150,139,876	$ -	$ -	$ 150,139,876
7							
8	Taxes Other than Income Taxes	Schedule F-5		26,076,868		80,479,885	$ 106,556,753
9							
10	Depreciation and Amortization Expense	Schedule F-3		92,971,711			$ 92,971,711
11							
12	Interest on Customer Deposits	Schedule F-7		26,170			$ 26,170
13							
14	Rate Base	Schedule B	$ 1,512,985,746				
15	Rate of Return	Schedule G	8.57%				
16				129,638,514			$ 129,638,514
17							
18	Income Taxes	Schedule F-6		48,602,650			$ 48,602,650
19							
20	Revenue Requirements			$ 447,455,789	$ 746,311,816	$ 80,479,885	$ 1,274,247,490
21							
22	Current Revenues	Schedule A					$ 1,249,189,011
23							
24	Proposed Change - Systemwide						$ 25,058,479
25							
26							

28 Note:

29

30 [1] Proposed Revenues are the result of the application of the proposed prospective rates to billing determinants.

32 2 The base revenue amount of $455,657,414 does not balance with the revenue requirement do to a rounding error: $ (4,177)

ATMOS ENERGY CORP., MID-TEX DIVISION
REVENUE REQUIREMENTS BY SERVICE CLASS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description (a)		Current Revenues (b)		Proposed Revenues [1] (c)		Proposed Change (d)	Percent Change (e)
1								
2	Residential (Base Revenue)	$	359,787,534	$	338,433,621	$	(21,353,912)	-5.94%
3	Residential (Rider GCR)		452,205,927		452,205,927		-	0.00%
4	Residential (Rider FF & Rider TAX)		54,741,928		53,302,318		(1,439,611)	-2.63%
5	Total Residential	$	866,735,389	$	843,941,866	$	(22,793,523)	-2.63%
6								
7	Commercial (Base Revenue)	$	84,881,892	$	84,225,991	$	(655,901)	-0.77%
8	Commercial (Rider GCR)		278,411,131		278,411,131		-	0.00%
9	Commercial (Rider FF & Rider TAX)		24,492,021		24,447,802		(44,219)	-0.18%
10	Total Commercial	$	387,785,044	$	387,084,924	$	(700,120)	-0.18%
11								
12	Industrial/Transportation (Base Revenue)	$	9,845,849	$	11,489,989	$	1,644,140	16.70%
13	Industrial/Transportation (Rider GCR)		15,694,758		15,694,758		-	0.00%
14	Industrial/Transportation (Rider FF & Rider TAX)		1,721,864		1,832,706		110,842	6.44%
15	Total Industrial/Transportation	$	27,262,470	$	29,017,452	$	1,754,982	6.44%
16								
17	Other Revenue (Base Revenue)	$	13,310,366	$	13,310,366	$	-	0.00%
18	Other Revenue (Rider GCR)		-		-		-	0.00%
19	Other Revenue (Rider FF & Rider TAX)		897,341		897,341		-	0.00%
20	Total Other Revenue	$	14,207,707	$	14,207,707	$	-	0.00%
21								
22	Base Revenue	$	467,825,640	$	447,459,966	$	(20,365,674)	-4.35%
23	Rider GCR		746,311,816		746,311,816		-	0.00%
24	Rider FF & Rider TAX		81,853,154		80,480,167		(1,372,987)	-1.68%
25	Total Operating Revenues	$	1,295,990,610	$	1,274,251,949	$	(21,738,661)	-1.68%
26								
27								
28	Note:							
29								
30	[1] Proposed Revenues are the result of the application of the proposed prospective rates to billing determinants.							

ATMOS ENERGY CORP., MID-TEX DIVISION
REVENUE REQUIREMENTS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Reference		Base Revenue	Rider GCR	Rider FF & Rider TAX	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1							
2	Rider GCR Part A	Schedule H		$ -	$ 588,090,591	$ -	$ 588,090,591
3	Rider GCR Part B	Schedule I			158,221,225		158,221,225
4	Total Rider GCR			$ -	$ 746,311,816	$ -	$ 746,311,816
5							
6	Operation and Maintenance Expenses	Schedule F-1		$ 150,139,876	$ -	$ -	$ 150,139,876
7							
8	Taxes Other than Income Taxes	Schedule F-5		26,076,868		80,479,885	106,556,753
9							
10	Depreciation and Amortization Expense	Schedule F-3		92,971,711			92,971,711
11							
12	Interest on Customer Deposits	Schedule F-7		26,170			26,170
13							
14	Rate Base	Schedule B	$ 1,512,985,746				
15	Rate of Return	Schedule G	8.57%				
16				129,638,514			129,638,514
17							
18	Income Taxes	Schedule F-6		48,602,650			48,602,650
19							
20	**Revenue Requirements**			$ 447,455,789	$ 746,311,816	$ 80,479,885	$ 1,274,247,490
21							
22	Current Revenues	Schedule A					$ 1,295,990,610
23							
24	Proposed Change - Prospective Rates Systemwide						$ (21,743,120)
25							
26	Proposed Change - Unincorporated Areas						$ (642,512)

ATMOS ENERGY CORP., MID-TEX DIVISION
REVENUE REQUIREMENTS BY SERVICE CLASS - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Current Revenues	Proposed Revenues [1]	Proposed Change	Percent Change
	(a)	(b)	(c)	(d)	(e)
1					
2	Residential (Base Revenue)	$ 322,261,415	$ 338,433,621	$ 16,172,206	5.02%
3	Residential (Rider GCR)	452,205,927	452,205,927	-	0.00%
4	Residential (Rider FF & Rider TAX)	52,212,041	53,302,318	1,090,277	2.09%
5	Total Residential	$ 826,679,383	$ 843,941,866	$ 17,262,483	2.09%
6					
7	Commercial (Base Revenue)	$ 76,028,813	$ 84,225,991	$ 8,197,178	10.78%
8	Commercial (Rider GCR)	278,411,131	278,411,131	-	0.00%
9	Commercial (Rider FF & Rider TAX)	23,895,175	24,447,802	552,627	2.31%
10	Total Commercial	$ 378,335,119	$ 387,084,924	$ 8,749,805	2.31%
11					
12	Industrial/Transportation (Base Revenue)	$ 10,523,242	$ 11,489,989	$ 966,746	9.19%
13	Industrial/Transportation (Rider GCR)	15,694,758	15,694,758	-	0.00%
14	Industrial/Transportation (Rider FF & Rider TAX)	1,767,531	1,832,706	65,175	3.69%
15	Total Industrial/Transportation	$ 27,985,531	$ 29,017,452	$ 1,031,921	3.69%
16					
17	Other Revenue (Base Revenue)	$ 13,310,366	$ 13,310,366	$ -	0.00%
18	Other Revenue (Rider GCR)	-	-	-	0.00%
19	Other Revenue (Rider FF & Rider TAX)	897,341	897,341	-	0.00%
20	Total Other Revenue	$ 14,207,707	$ 14,207,707	$ -	0.00%
21					
22	Base Revenue	$ 422,123,836	$ 447,459,966	$ 25,336,130	6.00%
23	Rider GCR	746,311,816	746,311,816	-	0.00%
24	Rider FF & Rider TAX	78,772,088	80,480,167	1,708,079	2.17%
25	Total Operating Revenues	$ 1,247,207,741	$ 1,274,251,949	$ 27,044,208	2.17%
26					
27					

28 Note:

29

30 [1] Proposed Revenues are the result of the application of the proposed prospective rates to billing determinants.

ATMOS ENERGY CORP., MID-TEX DIVISION
REVENUE REQUIREMENTS - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Reference		Base Revenue	Rider GCR	Rider FF & Rider TAX	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1							
2	Rider GCR Part A	Schedule H		$ -	$ 588,090,591	$ -	$ 588,090,591
3	Rider GCR Part B	Schedule I			158,221,225		158,221,225
4	Total Rider GCR			$ -	$ 746,311,816	$ -	$ 746,311,816
5							
6	Operation and Maintenance Expenses	Schedule F-1		$ 150,139,876	$ -	$ -	$ 150,139,876
7							
8	Taxes Other than Income Taxes	Schedule F-5		26,076,868		80,479,885	106,556,753
9							
10	Depreciation and Amortization Expense	Schedule F-3		92,971,711			92,971,711
11							
12	Interest on Customer Deposits	Schedule F-7		26,170			26,170
13							
14	Rate Base	Schedule B	$ 1,512,985,746				
15	Rate of Return	Schedule G	8.57%				
16				129,638,514			129,638,514
17							
18	Income Taxes	Schedule F-6		48,602,650			48,602,650
19							
20	**Revenue Requirements**			$ 447,455,789	$ 746,311,816	$ 80,479,885	$ 1,274,247,490
21							
22	Current Revenues	Schedule A					$ 1,247,207,741
23							
24	Proposed Change - Prospective Rates Systemwide						$ 27,039,749
25							
26	Proposed Change - Affected Cities						$ 27,347,835

ATMOS ENERGY CORP., MID-TEX DIVISION
RATE BASE
AS OF SEPTEMBER 30, 2011

Line No.	Description (a)	Reference (b)	Amount per Books (c)	Adjustment (d)	Total Requested (e)=(c)+(d)
1	Net Plant (1):				
2	Gross Plant	Schedule C	$ 2,868,712,055	$ (5,740,272)	$ 2,862,971,783
3	Accumulated Depreciation	Schedule D	1,151,380,652	(81,506,218)	1,069,874,434
4	Total Net Plant (Ln 2 minus Ln 3)		$ 1,717,331,403	$ 75,765,946	$ 1,793,097,349
5					
6	Additions:				
7	Materials & Supplies	WP_B-3	$ 768,737	$ 81,768	$ 850,505
8	Prepayments	WP_B-4	9,321,375	1,371,339	10,692,714
9	Pension and Other Postemployment Benefits Regulatory Asset	WP_B-7	-	1,954,911	1,954,911
10	Total Additions (Sum Ln 7 through Ln 9)		$ 10,090,112	$ 3,408,018	$ 13,498,130
11					
12	Deductions:				
13	Customer Deposits (235)	WP_B-5	$ 21,808,614	$ -	$ 21,808,614
14	Injuries and Damages Reserve	WP_B-2	3,519,327	(1,593,552)	1,925,776
15	Accumulated Deferred Income Taxes	WP_B-6	312,103,418	(70,780,672)	241,322,747
16	Rate Base Adjustments	WP_B-1	-	9,249,927	9,249,927
17	Total Deductions (Sum of Ln 13 through Ln 16)		$ 337,431,359	$ (63,124,296)	$ 274,307,063
18					
19	Total Cash Working Capital	Schedule E	$ -	$ (19,302,670)	$ (19,302,670)
20					
21	Rate Base (Ln 4 plus Ln 10 minus Ln 17 plus Ln 19)		$ 1,389,990,156	$ 122,995,590	$ 1,512,985,746
22					
23	Note:				
24	(1) Rate base excludes Poly 1 previously disallowed and includes other known and measurable rate base adjustments.				

ATMOS ENERGY CORP., MID-TEX DIVISION
RATE BASE ADJUSTMENTS
TEST YEAR ENDING SEPTEMBER 30, 2011

R

Line No.	Description		Amounts
	(a)		(b)
1	GUD 9670 Increment (WP_B-1.1)	$	8,656,857
2	GUD 9762 Increment (WP_B-1.2)		212,929
3	GUD 9869 Increment (WP_B-1.3)		260,507
4	Employee Expense Adjustment, January 2011-March 2012 (1)		73,343
5	Employee Expense Adjustment, TYE December 31, 2009 (3)		40,902
6	Employee Expense Adjustment, TYE September 30, 2010 (2), (3)		5,390
6a	ACSC Steel Service Line Revenue (CIAC) Adjustment	n/a	
6b	FAS 106 Adjustment		-
6c	Capitalized Incentive Adjustment - Remove SSU LTIP		-
	Capitalized Incentive Adjustment - Remove Mid-Tex LTIP		-
	Capitalized Incentive Adjustment - Limit Short VPP & MIP to 2% base pay		-
7			
8	Total (Sum of Ln 1 through Ln 6)	$	9,249,927
9			
10			
11	Note:		
12	1. See Page 2, Col (e), Ln 21.		
13	2. September 2010 adjustment is for 9 months, October through December 2010 is included in the test year adjustment on Line 4.		
14	3. The adjustments on Lines 5 and 6 include amounts for Shared Services Divisions 002 and 012 and Mid-Tex.		

ATMOS ENERGY CORP., MID-TEX DIVISION
EMPLOYEE EXPENSE ADJUSTMENT TO CAPITAL
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Shared Services - Customer Support (012)	Shared Services - General Office (002)	Mid-Tex Direct	Total Adjustment
	(a)	(b)	(c)	(d)	(e)
1	Twelve Months Ended September 30, 2011:				
2	Employee Expense Adjustment	$ 73,728	$ 317,271	$ 235,845	
3	Adjustment to align Oct10-May11 with GUD10000 (3)	1,021	17,914	4,650	
4	Subtotal (Ln 2 plus Ln 3)	$ 74,749	$ 335,186	$ 240,494	
5	Mid-Tex Allocation Factor (1) (2)	50.79%	37.60%	100.00%	
6					
7	Allocated Employee Expense Totals (Ln 4 times Ln 5)	$ 37,965	$ 126,030	$ 240,494	
8	Capitalization Factor (1)	10.40%	2.28%	0.00%	
9	Subtotal (Ln 7 times Ln 8)	$ 3,948	$ 2,878	$ -	
10					
11	Add Charges Direct to Capital:				
12	Employee Expense Adjustment	$ 45,131	$ 1,491	$ 13,369	
13	Adjustment to align Oct10-May11 with GUD10000 (3)	1,669	346	270	
14	Employee Expense Adjustment - October-December 2011	7,739	402	3,085	
15	Employee Expense Adjustment - January-March 2012	32,403	1,583	4,199	
16	Subtotal (Sum Ln 12 through Ln 15)	$ 86,941	$ 3,822	$ 20,923	
17	Mid-Tex Allocation Factor (1) (2)	50.79%	37.60%	100.00%	
18					
19	Allocated Employee Expense Charged Direct to Capital (Ln 16 times Ln 17)	$ 44,157	$ 1,437	$ 20,923	
20					
21	Total TY Ending September 30, 2011 Employee Expense Report Charges (Ln 9 plus Ln 19)	$ 48,105	$ 4,315	$ 20,923	$ 73,343
22					

23 Notes:
24 1. See WP_F-2.1, Col (b) and Col (c) Lns 7 and 11, for the Shared Services factors, as adjusted.
25 2. Mid-Tex costs are directly charged and not allocated.
26 3. An estimate was calculated to align the employee expense review for October 2010 through May 2011 with the changes in
27 guidelines ordered in GUD 10000, specifically limiting meals to $25 and lodging to $150.

	Data sources:	Location
1	EMP EXP DIV 002 6_11-9_11.xlsx	Original
2	EMP EXP DIV 002 10_10-5_11.xlsx	Original
3	EMP EXP DIV 012 6_11-9_11.xlsx	Original
4	Emp EXP DIV 012 10_10-5_11.xlsx	Original
5	EMP EXP DIV 080 10_10-5_11.xlsx	Original
6	EMP EXP DIV 080 6_11-9_11.xlsx	Original
7	2009 RRM Employee Expenses-Mid-Tex.xlsx	Appeal
8	2010 RRM Emp Exp Adj - CY 2010 Mid-Tex.xlsx	Original
9	Employee Expense Analysis for $25_$150_Details 12_8_11.xlsx	Original
10	IEXP_Oct11-Mar12 - SSU.xlsx	Appeal
11	2011_Oct-Dec_IEXP_Mid-Tex.xlsx	Appeal
12	2012_Jan-Mar_IEXP_ Mid-Tex.xlsx	Appeal

ATMOS ENERGY CORP., MID-TEX DIVISION
RATE BASE ADJUSTMENTS
TEST YEAR ENDING SEPTEMBER 30, 2011
GUD 9670 RATE BASE ADJUSTMENTS
AMORTIZATION SCHEDULE *

Line No.	Year Ended Dec. 31	Beginning of Year Rate Base Adjustment Amount	Annual Amortization (1)	End of Year Rate Base Adjustment Amount (2)	Balance as of September 30, 2011
	(a)	(b)	(c)	(d)	(e)
1	2005			$ 10,640,002	
2	2006	$ 10,640,002	$ 344,895	10,295,107	
3	2007	10,295,107	344,895	9,950,212	
4	2008	9,950,212	344,895	9,605,318	
5	2009	9,605,318	344,895	9,260,423	
6	2010	9,260,423	344,895	8,915,528	
7	2011	8,915,528	344,895	8,570,633	$ 8,656,857
8	2012	8,570,633	344,895	8,225,739	
9	2013	8,225,739	344,895	7,880,844	
10	2014	7,880,844	344,895	7,535,949	
11	2015	7,535,949	344,895	7,191,055	
12	2016	7,191,055	344,895	6,846,160	
13	2017	6,846,160	344,895	6,501,265	
14	2018	6,501,265	344,895	6,156,371	
15	2019	6,156,371	344,895	5,811,476	
16	2020	5,811,476	344,895	5,466,581	
17	2021	5,466,581	344,895	5,121,686	
18	2022	5,121,686	344,895	4,776,792	
19	2023	4,776,792	344,895	4,431,897	
20	2024	4,431,897	344,895	4,087,002	
21	2025	4,087,002	344,895	3,742,108	
22	2026	3,742,108	344,895	3,397,213	
23	2027	3,397,213	344,895	3,052,318	
24	2028	3,052,318	344,895	2,707,424	
25	2029	2,707,424	344,895	2,362,529	
26	2030	2,362,529	344,895	2,017,634	
27	2031	2,017,634	344,895	1,672,739	
28	2032	1,672,739	344,895	1,327,845	
29	2033	1,327,845	344,895	982,950	
30	2034	982,950	344,895	638,055	
31	2035	638,055	344,895	293,161	
32	2036	293,161	293,161	-	
33					

34 Notes:
35 1. The annual amortization is calculated based upon the period specified in
36 GUD 9670 Final Order, Schedule B, Page 2, Footnote 1.
37 2. The December 31, 2005 amount is per GUD 9670 Final Order, Schedule B,
38 Page 2, Ln 14.
39 * Totals may vary due to rounding.

ATMOS ENERGY CORP., MID-TEX DIVISION
RATE BASE ADJUSTMENTS
TEST YEAR ENDING SEPTEMBER 30, 2011
GUD 9762 RATE BASE ADJUSTMENTS - AMORTIZATION SCHEDULE *

Line No.	Year Ended June 30	Beginning of Year Rate Base Adjustment Amount	Annual Amortization (1)	End of Year Rate Base Adjustment Amount (2)	Balance as of September 30, 2011
	(a)	(b)	(c)	(d)	(e)
1	2007			$ 246,949	
2	2008	$ 246,949	$ 8,005	238,944	
3	2009	238,944	8,005	230,939	
4	2010	230,939	8,005	222,935	
5	2011	222,935	8,005	214,930	$ 212,929
6	2012	214,930	8,005	206,925	
7	2013	206,925	8,005	198,920	
8	2014	198,920	8,005	190,915	
9	2015	190,915	8,005	182,910	
10	2016	182,910	8,005	174,906	
11	2017	174,906	8,005	166,901	
12	2018	166,901	8,005	158,896	
13	2019	158,896	8,005	150,891	
14	2020	150,891	8,005	142,886	
15	2021	142,886	8,005	134,881	
16	2022	134,881	8,005	126,877	
17	2023	126,877	8,005	118,872	
18	2024	118,872	8,005	110,867	
19	2025	110,867	8,005	102,862	
20	2026	102,862	8,005	94,857	
21	2027	94,857	8,005	86,852	
22	2028	86,852	8,005	78,848	
23	2029	78,848	8,005	70,843	
24	2030	70,843	8,005	62,838	
25	2031	62,838	8,005	54,833	
26	2032	54,833	8,005	46,828	
27	2033	46,828	8,005	38,824	
28	2034	38,824	8,005	30,819	
29	2035	30,819	8,005	22,814	
30	2036	22,814	8,005	14,809	
31	2037	14,809	8,005	6,804	
32	2038	6,804	6,804	-	
33					

34 Notes:
35 1. The annual amortization is calculated based upon the period specified in GUD 9670 Final Order,
36 Schedule B, Page 2, Footnote 1.
37 2. The June 30, 2007 amount is per GUD 9762 Final Order, WP_B-1, Page 1, Ln 2+ Ln 3.
38
39 * Totals may vary due to rounding.

ATMOS ENERGY CORP., MID-TEX DIVISION
RATE BASE ADJUSTMENTS
TEST YEAR ENDING SEPTEMBER 30, 2011
GUD 9869 RATE BASE ADJUSTMENTS - DEPRECIATION SCHEDULE

Line No.	Year Ended Dec. 31	Beginning of Year Rate Base Adjustment Amount SSU Projects (1), (5)	Annual Depreciation (2), (6)	Ending Rate Base Balance SSU Projects	Beginning of Year Rate Base Adjustment Amount Mid-Tex Projects (1), (5)	Annual Depreciation (3), (6)	Ending Rate Base Balance Mid-Tex Projects	Beginning of Year Rate Base Adjustment Amount Employee Expense (1)	Amortization (4)	Ending Rate Base Balance Employee Expense	End of Year Rate Base Adjustment Amount (2)	Balance as of September 30, 2011
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	2008	$ 1,034,208			$ 176,806			$ 286,001			$ 1,497,015	
2			7.73%			3.48%						
3												
4	2009	$ 1,034,208	$ 79,941	$ 954,267	$ 176,806	$ 6,160	$ 170,646	$ 286,001	$ 9,271	$ 276,730	$ 276,730	
5	2010	954,267	79,941	874,327	170,646	6,160	164,486	276,730	9,271	267,460	267,460	
6	2011	874,327	79,941	794,386	164,486	6,160	158,326	267,460	9,271	258,189	258,189	$ 260,507
7	2012	794,386	79,941	714,445	158,326	6,160	152,167	258,189	9,271	248,918	248,918	
8	2013	714,445	79,941	634,505	152,167	6,160	146,007	248,918	9,271	239,647	239,647	
9	2014	634,505	79,941	554,564	146,007	6,160	139,847	239,647	9,271	230,377	230,377	
10	2015	554,564	79,941	474,623	139,847	6,160	133,687	230,377	9,271	221,106	221,106	
11	2016	474,623	79,941	394,683	133,687	6,160	127,527	221,106	9,271	211,835	211,835	
12	2017	394,683	79,941	314,742	127,527	6,160	121,367	211,835	9,271	202,565	202,565	
13	2018	314,742	79,941	234,801	121,367	6,160	115,207	202,565	9,271	193,294	193,294	
14	2019	234,801	79,941	154,861	115,207	6,160	109,047	193,294	9,271	184,023	184,023	
15	2020	154,861	79,941	74,920	109,047	6,160	102,888	184,023	9,271	174,753	174,753	
16	2021	74,920	74,920	-	102,888	6,160	96,728	174,753	9,271	165,482	165,482	
17	2022	-	-	-	96,728	6,160	90,568	165,482	9,271	156,211	156,211	
18	2023	-	-	-	90,568	6,160	84,408	156,211	9,271	146,941	146,941	
19	2024	-	-	-	84,408	6,160	78,248	146,941	9,271	137,670	137,670	
20	2025	-	-	-	78,248	6,160	72,088	137,670	9,271	128,399	128,399	
21	2026	-	-	-	72,088	6,160	65,928	128,399	9,271	119,128	119,128	
22	2027	-	-	-	65,928	6,160	59,768	119,128	9,271	109,858	109,858	
23	2028	-	-	-	59,768	6,160	53,609	109,858	9,271	100,587	100,587	
24	2029	-	-	-	53,609	6,160	47,449	100,587	9,271	91,316	91,316	
25	2030	-	-	-	47,449	6,160	41,289	91,316	9,271	82,046	82,046	
26	2031	-	-	-	41,289	6,160	35,129	82,046	9,271	72,775	72,775	
27	2032	-	-	-	35,129	6,160	28,969	72,775	9,271	63,504	63,504	
28	2033	-	-	-	28,969	6,160	22,809	63,504	9,271	54,234	54,234	
29	2034	-	-	-	22,809	6,160	16,649	54,234	9,271	44,963	44,963	
30	2035	-	-	-	16,649	6,160	10,489	44,963	9,271	35,692	35,692	
31	2036	-	-	-	10,489	6,160	4,330	35,692	9,271	26,421	26,421	
32	2037	-	-	-	4,330	4,330	-	26,421	9,271	17,151	17,151	
33	2038	-	-	-	-	-	-	17,151	9,271	7,880	7,880	
34	2039							7,880	7,880	-	-	
35												

36 Notes:
37 1. The 2008 amount in Col. (h) is from GUD9869 WP_B-1, Col (e), Ln 29 and the amounts in Cols. (b) and (e) are from GUD9869 Schedule C 12_31, Col (f), Lns 82A, 82B, 83C.
38 2. SSU Annual Depreciation rate is from GUD9869 Schedule F-3, Col (g), Ln 38 divided by Col (e) Ln 38
39 3. Mid-Tex Annual Depreciation rate is from GUD9869 Schedule F-3, Col (g), Ln 21 divided by Col (e) Ln 21
40 4. The annual amortization is calculated based upon the period specified in GUD 9670 Final Order, Schedule B, Page 2, Footnote 1
41 5. Amounts removed on Schedule C
42 6. Amounts removed on Schedule D

ATMOS ENERGY CORP., MID-TEX DIVISION
INJURIES AND DAMAGES AND WORKERS COMP RESERVES (1)
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Month Ending	Per Book Amount	Adjustments	Adjusted Amount	Allocation Factor	Allocated Amount
	(a)	(b)	(c)	(d) = (b)+(c)	(e)	(f) = (d)*(e)
1	**Mid-Tex**					
2	September 30, 2010	$ 1,848,158	$ -	$ 1,848,158	100.00%	$ 1,848,158
3	October 31, 2010	1,874,815	-	1,874,815	100.00%	1,874,815
4	November 30, 2010	1,926,933	-	1,926,933	100.00%	1,926,933
5	December 31, 2010	1,915,889	-	1,915,889	100.00%	1,915,889
6	January 31, 2011	1,949,534	-	1,949,534	100.00%	1,949,534
7	February 28, 2011	2,005,381	-	2,005,381	100.00%	2,005,381
8	March 31, 2011	2,045,551	-	2,045,551	100.00%	2,045,551
9	April 30, 2011	2,051,335	-	2,051,335	100.00%	2,051,335
10	May 31, 2011	2,054,618	-	2,054,618	100.00%	2,054,618
11	June 30, 2011	2,078,473	-	2,078,473	100.00%	2,078,473
12	July 31, 2011	2,120,421	-	2,120,421	100.00%	2,120,421
13	August 31, 2011	2,161,600	-	2,161,600	100.00%	2,161,600
14	September 30, 2011	1,840,533	-	1,840,533	100.00%	1,840,533
15						
16	**Shared Services - General Office (Div 002) (2)**					
17	September 30, 2010	$ 8,899,321	$ (8,727,453)	$ 171,868	37.60%	$ 64,622
18	October 31, 2010	8,771,858	(8,727,453)	44,404	37.60%	16,696
19	November 30, 2010	8,779,251	(8,727,453)	51,798	37.60%	19,476
20	December 31, 2010	6,934,764	(6,727,453)	207,311	37.60%	77,949
21	January 31, 2011	6,933,061	(6,727,453)	205,608	37.60%	77,309
22	February 28, 2011	6,894,398	(6,727,453)	166,944	37.60%	62,771
23	March 31, 2011	6,883,269	(6,727,453)	155,816	37.60%	58,587
24	April 30, 2011	5,886,555	(5,727,453)	159,101	37.60%	59,822
25	May 31, 2011	5,882,248	(5,728,624)	153,623	37.60%	57,762
26	June 30, 2011	5,885,072	(5,728,624)	156,448	37.60%	58,824
27	July 31, 2011	5,884,621	(5,728,624)	155,997	37.60%	58,655
28	August 31, 2011	5,886,412	(5,738,170)	148,242	37.60%	55,739
29	September 30, 2011	4,582,492	(4,238,170)	344,322	37.60%	129,465
30						
31	**Shared Services - Customer Support (Div 12)**					
32	September 30, 2010	$ (83,606)	$ -	$ (83,606)	50.79%	$ (42,464)
33	October 31, 2010	(83,606)	-	(83,606)	50.79%	(42,464)
34	November 30, 2010	(83,606)	-	(83,606)	50.79%	(42,464)
35	December 31, 2010	(84,554)	-	(84,554)	50.79%	(42,945)
36	January 31, 2011	(84,554)	-	(84,554)	50.79%	(42,945)
37	February 28, 2011	(87,069)	-	(87,069)	50.79%	(44,223)
38	March 31, 2011	(87,069)	-	(87,069)	50.79%	(44,223)
39	April 30, 2011	(87,069)	-	(87,069)	50.79%	(44,223)
40	May 31, 2011	(87,069)	-	(87,069)	50.79%	(44,223)
41	June 30, 2011	(87,069)	-	(87,069)	50.79%	(44,223)
42	July 31, 2011	(87,069)	-	(87,069)	50.79%	(44,223)
43	August 31, 2011	(87,069)	-	(87,069)	50.79%	(44,223)
44	September 30, 2011	(87,069)	-	(87,069)	50.79%	(44,223)
45	Total at September 30, 2011 (Col (f) = Sum Ln 14 plus Ln 29 plus Ln 44)	$ 3,519,327				$ 1,925,776
46						
47	Notes:					
48	1. Account 228.2 and Sub-accounts 28102 and 28101.					
49	2. The adjustment in Column (c) removes reserves not allocated to the divisions.					
50	Please refer to Cost Center 1903.					

**ATMOS ENERGY CORP., MID-TEX DIVISION
MATERIALS & SUPPLIES-ACCOUNTS 154 & 163
TEST YEAR ENDING SEPTEMBER 30, 2011**

Line No.	Month/Year Ending		Amount
	(a)		(b)
1	September 30, 2010	$	717,542
2	October 31, 2010		807,628
3	November 30, 2010		806,341
4	December 31, 2010		825,118
5	January 31, 2011		860,305
6	February 28, 2011		882,115
7	March 31, 2011		901,094
8	April 30, 2011		1,033,380
9	May 31, 2011		1,048,495
10	June 30, 2011		919,578
11	July 31, 2011		853,842
12	August 31, 2011		632,389
13	September 30, 2011		768,737
14			
15	13-Month Average	$	850,505

ATMOS ENERGY CORP., MID-TEX DIVISION
PREPAYMENTS-ACCOUNT 165
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Month/Year Ending	Amount	Adjustments (1)	Adjusted Total	Allocation %	Allocation to Mid-Tex
	(a)	(b)	(c)	(d) = (b)+(c)	(e)	(f) = (d)x(e)
	Mid-Tex					
1	September 30, 2010	$ 3,637,245	$ (221,983)	$ 3,415,263		
2	October 31, 2010	6,909,804	(385,599)	6,524,205		
3	November 30, 2010	4,777,047	(230,979)	4,546,068		
4	December 31, 2010	441,910	(9)	441,901		
5	January 31, 2011	3,832,294	(449,645)	3,382,649		
6	February 28, 2011	5,142,439	(155,035)	4,987,404		
7	March 31, 2011	6,151,261	(387,290)	5,763,970		
8	April 30, 2011	5,258,563	(939,396)	4,319,167		
9	May 31, 2011	10,123,281	(515,332)	9,607,950		
10	June 30, 2011	5,307,279	(284,982)	5,022,297		
11	July 31, 2011	8,415,545	(482,588)	7,932,957		
12	August 31, 2011	6,307,413	(333,301)	5,974,112		
13	September 30, 2011	3,817,309	(190,462)	3,626,846		
14						
15	13-Month Average	$ 5,393,953		$ 5,041,907	100%	$ 5,041,907
16						
17	**Shared Services-General Office**					
18	September 30, 2010	$ 14,863,224	$ -	$ 14,863,224		
19	October 31, 2010	14,459,113	-	14,459,113		
20	November 30, 2010	14,404,353	-	14,404,353		
21	December 31, 2010	12,695,953	-	12,695,953		
22	January 31, 2011	10,138,655	-	10,138,655		
23	February 28, 2011	8,249,976	-	8,249,976		
24	March 31, 2011	12,205,592	-	12,205,592		
25	April 30, 2011	12,321,659	-	12,321,659		
26	May 31, 2011	14,750,764	-	14,750,764		
27	June 30, 2011	12,987,761	-	12,987,761		
28	July 31, 2011	12,342,091	-	12,342,091		
29	August 31, 2011	10,835,572	-	10,835,572		
30	September 30, 2011	11,139,636	-	11,139,636		
31						
32	13-Month Average	$ 12,414,950		$ 12,414,950	37.60%	$ 4,668,021
33						
34	**Shared Services-Customer Support**					
35	September 30, 2010	$ 1,131,493	$ -	$ 1,131,493		
36	October 31, 2010	1,226,677	-	1,226,677		
37	November 30, 2010	997,263	-	997,263		
38	December 31, 2010	1,373,517	-	1,373,517		
39	January 31, 2011	1,895,983	-	1,895,983		
40	February 28, 2011	2,080,175	-	2,080,175		
41	March 31, 2011	2,099,996	-	2,099,996		
42	April 30, 2011	2,126,334	-	2,126,334		
43	May 31, 2011	2,147,759	-	2,147,759		
44	June 30, 2011	2,466,498	-	2,466,498		
45	July 31, 2011	2,507,546	-	2,507,546		
46	August 31, 2011	2,511,555	-	2,511,555		
47	September 30, 2011	2,590,201	-	2,590,201		
48						
49	13-Month Average	$ 1,935,000		$ 1,935,000	50.79%	$ 982,786
50						
51	Total Prepayments September 30	$ 9,321,375				
52						
53	Total Prepayments 13-Month Average (Ln 15 plus Ln 32 plus Ln 49)					$ 10,692,714
54						
55	Note:					
56	(1) Adjustment is to remove franchise fee prepayments for those cities that are handled as payment in arrears for ratemaking purposes.					

ATMOS ENERGY CORP., MID-TEX DIVISION
CUSTOMER DEPOSITS AND CUSTOMER ADVANCES FOR CONSTRUCTION
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Month/Year Ending		Amount
	(a)		(b)
1	**Customer Deposits - Acct 235**		
2	September 30, 2010	$	26,120,649
3	October 31, 2010		26,267,658
4	November 30, 2010		26,553,151
5	December 31, 2010		26,750,602
6	January 31, 2011		26,826,174
7	February 28, 2011		26,682,732
8	March 31, 2011		26,424,869
9	April 30, 2011		25,846,645
10	May 31, 2011		25,486,961
11	June 30, 2011		25,190,213
12	July 31, 2011		24,920,314
13	August 31, 2011		22,296,857
14	September 30, 2011		21,808,614
15			
16	**Customer Advances - Acct 252**		
17	September 30, 2010	$	-
18	October 31, 2010		-
19	November 30, 2010		-
20	December 31, 2010		-
21	January 31, 2011		-
22	February 28, 2011		-
23	March 31, 2011		-
24	April 30, 2011		-
25	May 31, 2011		-
26	June 30, 2011		-
27	July 31, 2011		-
28	August 31, 2011		-
29	September 30, 2011		-

ATMOS ENERGY CORP., MID-TEX DIVISION
ACCUMULATED DEFERRED INCOME TAXES-ACCOUNTS 192/282/283 (1)
TEST YEAR ENDING SEPTEMBER 30, 2011

DS

Line No.	Description	Assets / (Liabilities) - Per Book Balances	Adjustments (2)	ACSC Adjustments	Assets / (Liabilities) - Adjusted Balances
	(a)	(b)	(c)	(d)	(e) = (d)+(b)+(c)
1	Mid-Tex:				
2	Ad Valorem Taxes	$ (1,638,601)	$ 182,574	$ -	$ (1,456,026)
3	MIP/VPP Accrual	(120,088)		-	(120,088)
4	Vacation Accrual	4,157	-		4,157
5	Worker's Comp Insurance Reserve	811,043	-		811,043
6	SEBP Adjustment	377,035	22,106	-	399,141
7	Pension Expense	1,078,836	-		1,078,836
8	FAS 106 Adjustment	21,432,993	1,182,912	-	22,615,905
9	CWIP	(3,763,042)	[redacted]		-
10	Fixed Asset Cost Adjustment	(480,073,362)	(27,115,110)	-	(507,188,472)
11	Depreciation Adjustment	178,237,970	(14,343,783)	-	163,894,187
12	Deferred Gas Costs	(4,807,055)	4,807,055		-
13	Over Recoveries of PGA	4,183,751	(4,183,751)		-
14	TXU Goodwill Amortization	(60,833,129)	60,833,129		-
15	Deferred Expense Projects	-	(30,733)	-	(30,733)
16	Deferred Projects - TXU Acquistion	-	-		-
17	Unicap Section 263A Costs	1,716,530	(1,716,530)		-
18	Allowance for Doubtful Accounts	824,854	(824,854)	-	0
19	Clearing Account-Adjustment	1,370	-		1,370
20	Charitable Contribution Carryover	1,363,131	(1,363,131)		-
21	Prepayments	(1,412,408)	-		(1,412,408)
22	Rate Case Accrual	(417,690)	417,690		-
23	WACOG to FIFO Adjustment	(5,684,165)	5,684,165		-
24	Regulatory Liability-Mid-Tex	(1)	-		(1)
25	Intra Period Tax Allocation	-	-	-	-
26	State Net Operating Loss	1,044,589	-		1,044,589
27	Federal Tax on State NOL	(365,606)	-		(365,606)
28	Total Mid-Tex Direct (Sum Ln 2 through Ln 27)	$ (348,038,885)	$ 27,314,779	$ -	$ (320,724,105)
29					
30	SSU - Customer Support:				
31	MIP/VPP Accrual	$ (1,365,351)	$ 1,365,351		-
32	Vacation Accrual	5,572	-		5,572
33	Worker's Comp Insurance Reserve	(32,216)	-		(32,216)
34	CWIP	(3,583,122)	[redacted]		-
35	Fixed Asset Cost Adjustment	(40,064,057)	-		(40,064,057)
36	Depreciation Adjustment	30,038,691	-		30,038,691
37	Clearing Account-Adjustment	268	-		268
38	Charitable Contribution Carryover	15,210	(15,210)		-
39	Prepayments	(944,023)	-		(944,023)

ATMOS ENERGY CORP., MID-TEX DIVISION
ACCUMULATED DEFERRED INCOME TAXES-ACCOUNTS 192/282/283 (1)
TEST YEAR ENDING SEPTEMBER 30, 2011

DS

Line No.	Description	Assets / (Liabilities) - Per Book Balances	Adjustments (2)	ACSC Adjustments	Assets / (Liabilities) - Adjusted Balances
	(a)	(b)	(c)	(d)	(e) = (d)+(b)+(c)
40	Intra Period Tax Allocation	-	-		-
41	Total Customer Support (Sum Ln 31 through Ln 40)	$ (15,929,028)	$ 4,933,263		$ (10,995,765)
42	Allocation to Mid-Tex	50.79%	50.79%	50.79%	50.79%
43	SSU Customer Support Allocated to Mid-Tex (Ln 41 times Ln 42)	$ (8,090,353)	$ 2,505,604	$ -	$ (5,584,749)
44					
45					
46	SSU - General Office:				
47	Director's Deferred Bonus	$ 211,066	$ -		211,066
48	MIP/VPP Accrual	1,926,378	(1,926,378)		-
49	Miscellaneous Accrued	14,214	-		14,214
50	Self Insurance - Adjustment	1,568,123	(1,568,123)		-
51	Vacation Accrual	6,232	-		6,232
52	Worker's Comp Insurance Reserve	50,721	-		50,721
53	Rabbi Trust - True Up	4,279	(4,279)		-
54	SEBP Adjustment	25,510,036	(25,510,036)		-
55	Restricted Stock Grant Plan	5,319,945		-	5,319,945
56	Rabbi Trust	1,999,696	(1,999,696)		-
57	Restricted Stock - MIP	4,371,139	(4,371,139)		-
58	Director's Stock Awards	2,956,402			2,956,402
59	Director's Stock - Temp	(678,829)			(678,829)
60	Pension Expense	(14,371,402)	389,847	-	(13,981,554)
61	FAS 106 Adjustment	5,277,353	1,584,347	-	6,861,699
62	CWIP	204,465	[redacted]		-
63	Fixed Asset Cost Adjustment	(23,376,951)	(3,203,993)	-	(26,580,944)
64	Depreciation Adjustment	3,959,844	-		3,959,844
65	Section 481(a) Cushion Gas	556,809	(556,809)		-
66	Section 481(a) Line Pack Gas	67,557	(67,557)		-
67	IRS Audit Assessment - Cost	1,874,769	(1,874,769)		-
68	IRS Audit Assessment - Accum	(516,058)	516,058		-
69	Deferred Expense Projects	61,381	(388)	-	60,993
70	Allowance for Doubtful Accounts	2	-		2
71	Clearing Account-Adjustment	18,873	-		18,873
72	Charitable Contribution Carryover	217,029	(217,029)		-
73	Prepayments	(981,754)	-		(981,754)
74	Stock Option Expense	332,080	-	-	332,080
75	Federal & State Tax Interest	(411,878)	-		(411,878)
76	Regulatory Liability-Atmos 109	9,790	-		9,790

ATMOS ENERGY CORP., MID-TEX DIVISION
ACCUMULATED DEFERRED INCOME TAXES-ACCOUNTS 192/282/283 (1)
TEST YEAR ENDING SEPTEMBER 30, 2011

DS

Line No.	Description	Assets / (Liabilities) - Per Book Balances	Adjustments (2)	ACSC Adjustments	Assets / (Liabilities) - Adjusted Balances
	(a)	(b)	(c)	(d)	(e) = (d)+(b)+(c)
77	Intra Period Tax Allocation	(6)	6		-
78	FD - NOL Credit Carryforward - Utility (3)	261,286,612	(18,611,183)	-	242,675,429
79	FD - NOL Credit Carryforward - Non Reg (3)	(193,593,973)	193,593,973	-	-
80	FD - FAS 115 Adjustment	(1,516,693)	(1,674,842)	-	(3,191,535)
81	FD - Treasury Lock Adjustment - Realized	(4,924,724)	(371,616)	-	(5,296,340)
		24,984,990	(24,984,990)		
82	FD - FAS 158 Measure Date Change	4,573,142	-		4,573,142
83	FD - AMT Minimum Tax Credit	10,099,286	-		10,099,286
84	Total SSU General Office (Sum Ln 47 through Ln 84)	$ 117,089,946	$ 108,936,936	$ -	$ 226,026,882
85	Allocation to Mid-Tex	37.60%	37.60%	37.60%	37.60%
86	SSU General Office Allocated to Mid-Tex (Ln 84 times Ln 87)	$ 44,025,820	$ 40,960,288	$ -	$ 84,986,108
87					
88	Total SSU ADIT Allocated to Mid-Tex (Ln 43 plus Ln 87)	$ 35,935,466	$ 43,465,892	$ -	$ 79,401,359
89					
90	Total ADIT Direct and Allocated (Ln 28 plus Ln 89)	$ (312,103,418)	$ 70,780,672	$ -	$ (241,322,747)
91					

92 Note:
93 1. Credit amounts are in parentheses.
94 2. Please see relied upon "WP_B-6 Adjustment.xlsx" for details related to adjustments shown in Col (c).
95 Adjustments are for those items not included in rate base for ratemaking purposes and to include
96 other known and measurable ADIT adjustments.

ATMOS ENERGY CORP., MID-TEX DIVISION
PENSION AND OTHER POSTEMPLOYMENT BENEFITS REGULATORY ASSET
TEST YEAR ENDING SEPTEMBER 30, 2011
AMORTIZATION SCHEDULE *

Line No.	Year Ended March 31	Beginning of Year Rate Base Adjustment Amount	Annual Amortization (1)	End of Year Rate Base Adjustment Amount (2)	Balance as of March 31, 2012
	(a)	(b)	(c)	(d)	(e)
1	2012			[redacted]	$ 1,954,911
2	2013	$ 1,954,911	$ 195,491	1,759,420	
3	2014	1,759,420	195,491	1,563,929	
4	2015	1,563,929	195,491	1,368,438	
5	2016	1,368,438	195,491	1,172,947	
6	2017	1,172,947	195,491	977,455	
7	2018	977,455	195,491	781,964	
8	2019	781,964	195,491	586,473	
9	2020	586,473	195,491	390,982	
10	2021	390,982	195,491	195,491	
11	2022	195,491	195,491	0	
12					
13					

14 Notes:
15 1. The annual amortization of the Pension and Other Postemployment Benefits Regulatory Asset
16 cost has been included in O&M expense on WP_F-2.8. The annual amortization is based
17 on a ten year amortization period. The amounts shown on Line 1 include an adjustment
18 of ($6,956) which has not yet been recorded.
19 2. The Company has included in rate base, as a regulatory asset, the Company's calculated
20 Pension and Other Postemployment Benefits cost in accordance with
21 TEX. UTILITIES CODE, SECTION 104.059.
22 * Totals may vary due to rounding.

ATMOS ENERGY CORP., MID-TEX DIVISION
COMPONENTS OF RATE BASE- GROSS PLANT
AS OF SEPTEMBER 30, 2011

Line No.	Account	Account Description	Reference	Amount Per Books	Adjustments (1)	ACSC Adjustments	Adjusted Balance
	(a)	(b)	(c)	(d)	(e)		(f)=(d)+(e)
1	Mid-Tex:						
2	Distribution Plant						
3	374	Land		$ 774,213	$ 5,435	$ -	$ 779,648
4	374	Land Rights		3,178,861	23,438	-	3,202,299
5	374	Land & Land Rights		1,309	(1,309)	-	-
6	375	Structures & Improvements		1,393,645	74,925	-	1,468,570
7	376.00	Mains-Cathodic Protection		188,391,482	(51,541,261)	-	136,850,221
8	376.01	Mains-Steel		388,800,889	40,396,790	-	429,197,678
9	376.02	Mains-Plastic		922,055,953	(11,225,708)	-	910,830,245
10	378	M&R Station Equipment - General		32,468,534	6,583,761	-	39,052,296
11	379	M&R Station Equipment - City Gate		5,513,898	-	-	5,513,898
12	380	Services		750,800,968	7,628,757	-	758,429,725
13	381	Meters		159,201,494	2,409,373	-	161,610,868
14	382	Meter Installations		95,276,114	18,574,780	-	113,850,895
15	383	House Regulators		47,215,158	137,503	-	47,352,660
16	385	Industrial M&R Station Equipment		1,256,221	24,372	-	1,280,593
17		Total (Sum of Ln 3 through Ln 16)		$ 2,596,328,739	$ 13,090,855	$ -	$ 2,609,419,594
18							
19	General Plant						
20	302	Franchises & Consents		$ 18,896	$ -	$ -	$ 18,896
21	303	Computer Software		3,598,424	(212,093)	-	3,386,331
22	389	Land		3,278,185	704,581	-	3,982,767
23	390	Structures & Improvements		27,227,471	2,482,545	-	29,710,016
24	390	Air Conditioning Equipment		144,486	2,746	-	147,233
25	391	Office Furniture & Equipment		6,571,954	(112,267)	-	6,459,687
26	392	Transportation Equipment		3,492,630	(207,846)	-	3,284,784
27	393	Stores Equipment		144,748	-	-	144,748
28	394	Tools, Shop, and Garage Equipment		11,389,923	388,251	-	11,778,174
29	395	Laboratory Equipment		220,788	108,578	-	329,367
30	396	Power Oper. Tool & Work Equipment		2,277,734	(10,632)	-	2,267,102
31	397	Radio Communication Equipment		8,310,661	(142,736)	-	8,167,925
32	398	Miscellaneous Equipment		18,694,758	(123,588)	-	18,571,170
33	399	Other Tangible Property		4,270,297	(4,270,297)	-	-
34	399.01	Other Tangible Property-Servers Hardware		899,933	(325,128)	-	574,805
35	399.02	Other Tangible Property-Servers Software		467,576	(398,403)	-	69,173
36	399.03	Other Tangible Property-Network-Hardware		921,208	(593,545)	-	327,663
37	399.06	Other Tangible Property-PC Hardware		8,500,875	(1,202,944)	-	7,297,931
38	399.07	Other Tangible Property-PC Software		1,068,243	(17,740)	-	1,050,503
39	399.08	Other Tangible Property-Application Software		2,808,473	(667,830)	-	2,140,643
40		Total (Sum of Ln 20 through Ln 39)		$ 104,307,265	$ (4,598,346)	$ -	$ 99,708,919
41							
42		Total Mid-Tex Direct (Ln 17 plus Ln 40)		$ 2,700,636,005	$ 8,492,509	$ -	$ 2,709,128,514

ATMOS ENERGY CORP., MID-TEX DIVISION
COMPONENTS OF RATE BASE- GROSS PLANT
AS OF SEPTEMBER 30, 2011

Line No.	Account	Account Description	Reference	Amount Per Books	Adjustments (1)	ACSC Adjustments	Adjusted Balance
	(a)	(b)	(c)	(d)	(e)		(f)=(d)+(e)
43							
44							
45	SSU - Customer Support (Div 012):						
46	General Plant						
47	389	Land & Land Rights		$ 2,874,240	$ -	$ -	$ 2,874,240
48	390	Structures & Improvements		13,168,087	12,018	-	13,180,105
49	390.09	Improvements to Leased Premises		4,437,465	(31,602)	-	4,405,863
50	391	Office Furniture & Equipment		1,054,834	69,657	-	1,124,491
51	391.02	Remittance Processing Equipment		-	-	-	-
52	391.03	Office Furniture & Equipment		-	-	-	-
53	392	Transportation Equipment		-	-	-	-
54	393	Stores Equipment		-	-	-	-
55	394	Tools & Work Equipment		-	-	-	-
56	397	Communication Equipment - Telephone		26,143,741	(11,935,816)	-	14,207,925
57	398	Miscellaneous Equipment		9,533	(6,553)	-	2,980
58	399	Other Tangible Property		-	-	-	-
59	399.01	Other Tangible Property-Servers Hardware		13,047,889	(6,904,512)	-	6,143,377
60	399.02	Other Tangible Property-Servers Software		7,582,366	(5,150,151)	-	2,432,216
61	399.03	Other Tangible Property-Network-Hardware		913,069	(394,907)	-	518,162
62	399.04	Other Tangible Property-CPU		-	-	-	-
63	399.05	Other Tangible Property-MF Hardware		-	-	-	-
64	399.06	Other Tangible Property-PC Hardware		2,549,162	(1,448,884)	-	1,100,278
65	399.07	Other Tangible Property-PC Software		3,327,195	86,941	-	3,414,136
66	399.08	Other Tangible Property-Application Software		93,618,084	34,156	-	93,652,240
67	399.09	Other Tangible Property-System Software		-	-	-	-
68	399.24	Other Tangible Property-GenStartupCost		23,172,326	-	-	23,172,326
69		Total (Sum of Ln 47 through Ln 68)		$ 191,897,992	$ (25,669,653)	$ -	$ 166,228,339
70		Allocation to Mid-Tex		50.79%	50.79%	50.79%	50.79%
71		Customer Support Allocated to Mid-Tex (Ln 69 times Ln 70)		$ 97,464,990	$ (13,037,617)	$ -	$ 84,427,373
72	SSU - Customer Support (Div 012):						
73	General Plant						
74	Charles K. Vaughn Center						
75	389	Land & Land Rights		$ 1,887,123	$ -	$ -	$ 1,887,123
76	390.10	Structures & Improvements		10,400,518	-	-	10,400,518
77	397.10	Communication Equipment		271,621	-	-	271,621
78	399.10	Other Tangible Equipment		90,541	(200)	-	90,341
79	399.16	PC Hardware		194,015	-	-	194,015
80	399.17	PC Software		90,541	-	-	90,541
81		Total (Sum of Ln 75 through Ln 80)		$ 12,934,358	$ (200)	$ -	$ 12,934,159
82		Allocation to Mid-Tex		76.47%	76.47%	76.47%	76.47%
83		Customer Support: Charles K. Vaughn Center Allocated to Mid-Tex (Ln 81 times Ln 82)		$ 9,890,330	$ (153)	$ -	$ 9,890,177
84		Total Customer Support Allocated to Mid-Tex (Ln 71 plus Ln 83)		$ 107,355,320	$ (13,037,769)	$ -	$ 94,317,551
85							
86							

ATMOS ENERGY CORP., MID-TEX DIVISION
COMPONENTS OF RATE BASE- GROSS PLANT
AS OF SEPTEMBER 30, 2011

Line No.	Account	Account Description	Reference	Amount Per Books	Adjustments (1)	ACSC Adjustments	Adjusted Balance
	(a)	(b)	(c)	(d)	(e)		(f)=(d)+(e)
87	SSU - General Office (Div 002):						
88	General Plant						
89	390	Improvements to Leased Premises		$ 8,253,038	$ (152,347)	$ -	$ 8,100,692
90	391	Office Furniture & Equipment		11,475,202	(1,085,827)	-	10,389,375
91	391.02	Remittance Processing Equipment		-	-	-	-
92	391.03	Office Furniture & Equipment		-	-	-	-
93	392	Transportation Equipment		96,290	2,853	-	99,143
94	393	Stores Equipment		-	-	-	-
95	394	Tools & Work Equipment		83,933	101,468	-	185,402
96	395	Laboratory Equipment		-	12,100	-	12,100
97	397	Communication Equipment - Telephone		2,355,236	(162,105)	-	2,193,131
98	398	Miscellaneous Equipment		236,331	144,085	-	380,416
99	399	Other Tangible Property		162,268	-	-	162,268
100	399.01	Other Tangible Property-Servers Hardware		24,760,357	(1,089,375)	-	23,670,982
101	399.02	Other Tangible Property-Servers Software		13,285,696	804,701	-	14,090,396
102	399.03	Other Tangible Property-Network-Hardware		3,911,025	(39,486)	-	3,871,538
103	399.04	Other Tangible Property-CPU		1,095,465	(1,095,465)	-	-
104	399.05	Other Tangible Property-MF Hardware		1,159,964	(1,159,964)	-	-
105	399.06	Other Tangible Property-PC Hardware		4,704,521	(2,146,741)	-	2,557,781
106	399.07	Other Tangible Property-PC Software		1,769,409	85,547	-	1,854,955
107	399.08	Other Tangible Property-Application Software		82,235,740	2,626,044	-	84,861,784
108	399.09	Other Tangible Property-System Software		2,614,619	(0)	-	2,614,619
109	399.24	Other Tangible Property-GenStartupCost		-	-	-	-
110		Total (Sum of Ln 89 through Ln 109)		$ 158,199,095	$ (3,154,513)	$ -	$ 155,044,583
111		Allocation to Mid-Tex		37.60%	37.60%	37.60%	37.60%
112		General Office Allocated to Mid-Tex (Ln 110 times Ln 111)		$ 59,482,860	$ (1,186,097)	$ -	$ 58,296,763
113	SSU - General Office (Div 002):						
114	General Plant						
115	Greenville Data Center (010.11520)						
116	390.05	G-Structures & Improvements		$ 9,154,286	$ (66,386)	$ -	$ 9,087,900
117	391.04	G-Office Furniture & Equip.		63,741	-	-	63,741
118		Total (Sum of Ln 116 through Ln 117)		$ 9,218,027	$ (66,386)	$ -	$ 9,151,641
119		Allocation to Mid-Tex		13.43%	13.43%	13.43%	13.43%
120		General Office Greenville Data Center Allocated to Mid-Tex (Ln 118 times Ln 119)		$ 1,237,870	$ (8,915)	$ -	$ 1,228,956
121							
122		Total General Office Allocated to Mid-Tex (Ln 112 plus Ln 120)		$ 60,720,730	$ (1,195,012)	$ -	$ 59,525,719
123							
124		Total SSU Plant Allocated to Mid-Tex (Ln 84 plus Ln 122)		$ 168,076,050	$ (14,232,781)	$ -	$ 153,843,269
125							
126		Total Mid-Tex Gross Plant (Ln 42 plus Ln 124)		$ 2,868,712,055	$ (5,740,272)	$ -	$ 2,862,971,783

ATMOS ENERGY CORP., MID-TEX DIVISION
COMPONENTS OF RATE BASE- ACCUMULATED DEPRECIATION
AS OF SEPTEMBER 30, 2011

Line No.	Account	Account Description	Reference	Amount Per Books	Adjustments	ACSC Adjustments	Adjusted Balance
	(a)	(b)	(c)	(d)	(e)		(f)=(d)+(e)
1	Mid-Tex:						
2	Distribution Plant						
3	374	Land		$ -	$ 7,298	$ -	$ 7,298
4	374	Land Rights		1,623,353	27,810	-	1,651,163
5	375	Structures & Improvements		1,227,444	101,027	-	1,328,471
6	376	Mains-Cathodic Protection		84,004,993	(44,047,085)	-	39,957,908
7	376	Mains-Steel		83,914,593	16,329,774	-	100,244,367
8	376	Mains-Plastic		268,947,790	(26,475,429)	-	242,472,361
9	378	M&R Station Equipment - General		15,234,984	2,967,093	-	18,202,077
10	379	M&R Station Equipment - City Gate		2,912,225	69,221	-	2,981,446
11	380	Services		467,515,762	(18,127,171)	-	449,388,591
12	381	Meters		68,639,974	716,240	-	69,356,213
13	382	Meter Installations		31,953,148	1,931,561	-	33,884,709
14	383	House Regulators		14,933,275	(2,583,876)	-	12,349,400
15	385	Industrial M&R Station Equipment		149,324	24,630	-	173,954
16		Total (Sum of Ln 3 through Ln 15)		$ 1,041,056,865	$ (69,058,907)	$ -	$ 971,997,957
17							
18	General Plant						
19	302	Franchises & Consents		$ 7,231	$ -	$ -	$ 7,231
20	303	Computer Software		3,598,424	(123,721)	-	3,474,703
21	389	Land		219,843	25,967	-	245,810
22	390	Structures & Improvements		14,335,138	144,163	-	14,479,301
23	390	Air Conditioning Equipment		13,067	1,050	-	14,118
24	391	Office Furniture & Equipment		2,428,425	(33,265)	-	2,395,160
25	392	Transportation Equipment		(1,383,520)	(157,685)	-	(1,541,204)
26	393	Stores Equipment		13,020	2,439	-	15,459
27	394	Tools, Shop, and Garage Equipment		853,384	87,733	-	941,117
28	395	Laboratory Equipment		(110,120)	103,662	-	(6,458)
29	396	Power Oper. Tool & Work Equipment		(1,518,906)	-	-	(1,518,906)
30	397	Radio Communication Equipment		1,592,499	(85,662)	-	1,506,837
31	398	Miscellaneous Equipment		15,028,106	21,571	-	15,049,678
32	399	Other Tangible Property		3,980,437	(4,257,951)	-	(277,514)
33	399.01	Other Tangible Property-Servers Hardware		319,638	(279,743)	-	39,895
34	399.02	Other Tangible Property-Servers Software		278,318	(380,233)	-	(101,915)
35	399.03	Other Tangible Property-Network-Hardware		250,662	(559,934)	-	(309,271)
36	399.06	Other Tangible Property-PC Hardware		2,550,438	(1,329,483)	-	1,220,955
37	399.07	Other Tangible Property-PC Software		217,130	44,815	-	261,944
38	399.08	Other Tangible Property-Application Software		509,485	(554,393)	-	(44,908)
39	RWIP	Retirement Work in Progress		(41,660,746)	5,457,315	-	(36,203,431)
40		Total (Sum of Ln 19 through Ln 39)		$ 1,521,955	$ (1,873,356)	$ -	$ (351,401)
41							
42		Total Mid-Tex Direct (Ln 16 plus Ln 40)		$ 1,042,578,820	$ (70,932,263)	$ -	$ 971,646,556
43							
44							

ATMOS ENERGY CORP., MID-TEX DIVISION
COMPONENTS OF RATE BASE- ACCUMULATED DEPRECIATION
AS OF SEPTEMBER 30, 2011

Line No.	Account (a)	Account Description (b)	Reference (c)	Amount Per Books (d)	Adjustments (e)	ACSC Adjustments	Adjusted Balance (f)=(d)+(e)
45	SSU - Customer Support (Div 012):						
46	General Plant						
47	390	Structures & Improvements		$ 589,389	$ 579,255	$ -	$ 1,168,645
48	390.09	Improvements to Leased Premises		2,836,296	172,936	-	3,009,232
49	391	Office Furniture & Equipment		65,361	13,069	-	78,430
50	391.02	Remittance Processing Equipment		-	-	-	-
51	391.03	Office Furniture & Equipment		-	-	-	-
52	392	Transportation Equipment		-	-	-	-
53	393	Stores Equipment		-	-	-	-
54	394	Tools & Work Equipment		-	-	-	-
55	397	Communication Equipment - Telephone		16,607,891	(11,057,265)	-	5,550,626
56	398	Miscellaneous Equipment		1,306	(1,658)	-	(353)
57	399	Other Tangible Property		(1,031)	-	-	(1,031)
58	399.01	Other Tangible Property-Servers Hardware		12,142,549	(6,562,455)	-	5,580,094
59	399.02	Other Tangible Property-Servers Software		7,492,590	(5,658,083)	-	1,834,507
60	399.03	Other Tangible Property-Network-Hardware		504,991	(409,431)	-	95,560
61	399.04	Other Tangible Property-CPU		-	-	-	-
62	399.05	Other Tangible Property-MF Hardware		-	-	-	-
63	399.06	Other Tangible Property-PC Hardware		1,911,712	(1,351,477)	-	560,235
64	399.07	Other Tangible Property-PC Software		2,975,412	139,080	-	3,114,493
65	399.08	Other Tangible Property-Application Software		77,070,004	4,885,307	-	81,955,312
66	399.09	Other Tangible Property-System Software		-	-	-	-
67	399.24	Other Tangible Property-GenStartupCost		23,168,336	0	-	23,168,336
68	RWIP	Retirement Work in Progress		(865)	(22,653)	-	(23,518)
69		Total (Sum of Ln 47 through Ln 68)		$ 145,363,941	$ (19,273,373)	$ -	$ 126,090,568
70		Allocation to Mid-Tex		50.79%	50.79%	49.46%	50.79%
71		Customer Support Allocated to Mid-Tex (Ln 69 times Ln 70)		$ 73,830,346	$ (9,788,946)	$ -	$ 64,041,399
72	SSU - Customer Support (Div 012):						
73	General Plant						
74	Charles K. Vaughn Center						
75	389	Land & Land Rights		$ -	$ -	$ -	$ -
76	390.10	Structures & Improvements		895,200	467,587	-	1,362,787
77	397.10	Communication Equipment		23,806	11,371	-	35,178
78	399.10	Other Tangible Equipment		6,861	2,358	-	9,219
79	399.16	PC Hardware		33,508	14,482	-	47,990
80	399.17	PC Software		8,599	4,274	-	12,872
81		Total (Sum of Ln 75 through Ln 80)		$ 967,974	$ 500,072	$ -	$ 1,468,045
82		Allocation to Mid-Tex		76.47%	76.47%	76.47%	76.47%
83		Customer Support: Charles K. Vaughn Center Allocated to Mid-Tex (Ln 81 times Ln 82)		$ 740,166	$ 382,383	$ -	$ 1,122,549
84							
85		Total Customer Support Allocated to Mid-Tex (Ln 71 plus Ln 83)		$ 74,570,512	$ (9,406,563)	$ -	$ 65,163,949
86							

ATMOS ENERGY CORP., MID-TEX DIVISION
COMPONENTS OF RATE BASE- ACCUMULATED DEPRECIATION
AS OF SEPTEMBER 30, 2011

Line No.	Account (a)	Account Description (b)	Reference (c)	Amount Per Books (d)	Adjustments (e)	ACSC Adjustments	Adjusted Balance (f)=(d)+(e)
87							
88	SSU - General Office (Div 002):						
89	General Plant						
90	390	Improvements to Leased Premises		$ 8,091,940	$ 259,162	$ -	$ 8,351,102
91	391	Office Furniture & Equipment		7,371,465	(665,783)	-	6,705,682
92	391.02	Remittance Processing Equipment		5,860	-	-	5,860
93	391.03	Office Furn. - Copiers & Type		2,888	-	-	2,888
94	392	Transportation Equipment		18,000	9,911	-	27,911
95	393	Stores Equipment		758	-	-	758
96	394	Tools & Work Equipment		15,187	6,258	-	21,444
97	395	Laboratory Equipment		-	232	-	232
98	397	Communication Equipment - Telephone		815,723	(68,021)	-	747,701
99	398	Miscellaneous Equipment		79,943	(12,914)	-	67,029
100	399	Other Tangible Property		45,878	5,234	-	51,112
101	399.01	Other Tangible Property-Servers Hardware		8,340,234	(2,245,518)	-	6,094,715
102	399.02	Other Tangible Property-Servers Software		4,223,186	(398,920)	-	3,824,266
103	399.03	Other Tangible Property-Network-Hardware		1,762,796	(76,537)	-	1,686,259
104	399.04	Other Tangible Property-CPU		1,111,824	(1,094,893)	-	16,931
105	399.05	Other Tangible Property-MF Hardware		1,174,870	(1,159,601)	-	15,269
106	399.06	Other Tangible Property-PC Hardware		4,442,359	(2,084,310)	-	2,358,049
107	399.07	Other Tangible Property-PC Software		1,671,823	80,837	-	1,752,660
108	399.08	Other Tangible Property-Application Software		48,758,042	4,195,484	-	52,953,526
109	399.09	Other Tangible Property-System Software		2,722,303	2,322	-	2,724,625
110	399.24	Other Tangible Property-GenStartupCost		-	-	-	-
111		Retirement Work in Progress		(153)	-	-	(153)
112		Total (Sum of Ln 90 through Ln 111)		$ 90,654,926	$ (3,247,059)	$ -	$ 87,407,867
113		Allocation to Mid-Tex		37.60%	37.60%	36.59%	37.60%
114		General Office Allocated to Mid-Tex (Ln 112 times Ln 113)		$ 34,086,252	$ (1,220,894)	$ -	$ 32,865,358
115	SSU - General Office (Div 002):						
116	General Plant						
117	Greenville Data Center (010.11520)						
118	390.05	G-Structures & Improvements		$ 1,076,794	$ 397,697	$ -	$ 1,474,491
119	391.04	G-Office Furniture & Equip.		3,482	725	-	4,207
120		Total (Sum of Ln 118 through Ln 119)		$ 1,080,276	$ 398,422	$ -	$ 1,478,698
121		Allocation to Mid-Tex		13.43%	13.43%	13.43%	13.43%
122		General Office: Greenville Data Center Allocated to Mid-Tex (Ln 120 times Ln 121)		$ 145,068	$ 53,503	$ -	$ 198,571
123							
124		Total General Office Allocated to Mid-Tex (Ln 114 plus Ln 122)		$ 34,231,320	$ (1,167,391)	$ -	$ 33,063,929
125							
126		Total SSU Accumulated Depreciation Allocated to Mid-Tex (Ln 85 plus Ln 124)		$ 108,801,832	$ (10,573,954)	$ -	$ 98,227,878
127							
128		Total Mid-Tex Accumulated Depreciation (Ln 42 plus Ln 126)		$ 1,151,380,652	$ (81,506,218)	$ -	$ 1,069,874,434
129							

130 Note:
131 1. Please see relied upon "Schedule D Adjustment.xlsx" for details related to adjustments shown in Col (e). The adjustments include removal of Poly 1
132 previously disallowed and other known and measurable adjustments to accumulated depreciation.

ATMOS ENERGY CORP., MID-TEX DIVISION
CASH WORKING CAPITAL
TEST YEAR ENDING SEPTEMBER 30, 2011

E1

Line No.	Description (a)	Test Year Expenses (b)	Reference (c)	Avg. Daily Expense (d)=(b)/365	Revenue Lag (e)	Expense Lag (f)	Net Lag (g)=(e)-(f)	Working Capital Requirement (h)=(d)x(g)
1	Gas Supply Expense							
2	Rider GCR Part A	$ 588,090,591	Schedule H	$ 1,611,207	36.17	40.40	(4.23)	$ (6,814,718)
3	Rider GCR Part B	158,221,225	Schedule I	433,483	36.17	38.20	(2.03)	(879,970)
4	Total Gas Supply Expense	$ 746,311,816	Sum Ln 2 through Ln 3					$ (7,694,688)
5								
6	Operation & Maintenance							
7	Other O&M - Labor (1)	$ 56,449,315	(2)	$ 154,656	36.17	25.71	10.46	$ 1,617,698
8	Other O&M - Non-Labor	93,690,561	Ln 9 minus Ln 7	256,686	36.17	32.24	3.93	1,008,778
8a		-		-	-	-	-	-
8b		-		-	-	-	-	-
8c		-		-	-	-	-	-
8d		-		-	-	-	-	-
9	Total Operation & Maintenance	$ 150,139,876	Schedule F-1					$ 2,626,476
10								
11	Taxes Other Than Income							
12	Ad Valorem	$ 21,129,326	Schedule F-5	$ 57,889	36.17	213.50	(177.33)	$ (10,265,379)
13	Payroll Taxes	2,722,791	Schedule F-5	7,460	36.17	31.61	4.56	34,016
14	Franchise Fees (3)	27,777,001	Schedule F-5 x CWC factor	76,101	36.17	99.24	(63.07)	(4,799,896)
15	Railroad Commission Fee	62,540	Schedule F-5	171	36.17	94.84	(58.67)	(10,053)
16								
17	Allocated Taxes-Shared Services:							
18	Ad Valorem	421,511	WP_F-5.1,Col (b), Ln 59	1,155	36.17	213.50	(177.33)	(204,785)
19	Payroll Taxes	1,715,313	WP_F-5.1,Col (b), Ln 48	4,699	36.17	[redacted]	4.56	21,430
20	Total Taxes Other Than Income Taxes	$ 53,828,483	Sum Ln 12 through Ln 19					$ (15,224,667)
21								
22	State Income Tax ("Gross Margin")	$ 4,438,667	Schedule F-6	$ 12,161	36.17	(47.00)	83.17	$ 1,011,408
23								
24	Current Federal Income Tax	$ -	(4)	$ -	36.17	36.75	(0.58)	$ -
25								
26	Interest on Customer Deposits	$ 26,170	Schedule F-7	$ 72	36.17	331.83	(295.66)	$ (21,199)
27								
27a								
27b								
28	Total Cash Working Capital Requirement		Sum Lns 4,9,20,22,24,26					$ (19,302,670)
29								

30 Note:
31 1. Includes Mid-Tex and SSU Labor and Mid-Tex Direct MIP/VIP (excludes SSU MIP/VPP)
32 2. WP_F-5.1, Col (b), Ln 43 + WP_F-2.1, Col (e) Ln 17 + WP_F-2.1, Col (c) Ln 29+ Mid-Tex MIP/VPP
33 3. Paid in Arrears portion of Franchise Fees is per the CWC study
34 4. Schedule F-6, page 1, Col (b), Ln 1 plus WP_B-6 Col (f), Ln 90 minus WP_E-1 Col (e), Ln 97 is less than zero so zero is used.

	Data Source:	Location
1	2011 MID TEX CWC final.xlsx	Appeal
2	MidTex O&M for 12 months ended Sep.11.xlsx	Original

ATMOS ENERGY CORP., MID-TEX DIVISION
BEGINNING BALANCE ACCUMULATED DEFERRED INCOME TAXES-ACCOUNTS 192/282/283 (1)
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Assets / (Liabilities) - Per Book Balances at 9/30/2010	Adjustments	Assets / (Liabilities) - Adjusted Balances at 9/30/10
	(a)	(b)	(c)	(d) = (b)+(c)
1	Mid-Tex:			
2	Ad Valorem Taxes	$ (1,697,694)	$ -	$ (1,697,694)
3	MIP/VPP Accrual	(594,531)	-	(594,531)
4	Vacation Accrual	10,503	-	10,503
5	Worker's Comp Insurance Reserve	683,818	-	683,818
6	SEBP Adjustment	322,147	-	322,147
7	Pension Expense	1,078,836	-	1,078,836
8	FAS 106 Adjustment	19,015,394	-	19,015,394
9	CWIP	1,755,145	(1,755,145)	-
10	Fixed Asset Cost Adjustment	(426,843,667)	-	(426,843,667)
11	Depreciation Adjustment	194,122,039	-	194,122,039
12	Deferred Gas Costs	7,564,444	(7,564,444)	-
13	Over Recoveries of PGA	(9,109,988)	9,109,988	-
14	TXU Goodwill Amortization	(51,942,710)	51,942,710	-
15	Deferred Expense Projects	(313,969)	-	(313,969)
16	Deferred Projects - TXU Acquistion	660,148	(660,148)	-
17	Unicap Section 263A Costs	1,154,831	(1,154,831)	-
18	Allowance for Doubtful Accounts	1,776,048	-	1,776,048
19	Clearing Account-Adjustment	1,370	-	1,370
20	Charitable Contribution Carryover	808,045	(808,045)	-
21	Prepayments	(1,345,777)	-	(1,345,777)
22	Rate Case Accrual	(951,353)	951,353	-
23	WACOG to FIFO Adjustment	(6,757,261)	6,757,261	-
24	Regulatory Liability-Mid-Tex	(1)	-	(1)
25	Intra Period Tax Allocation	-	-	-
26	State Net Operating Loss	-	-	-
27	Federal Tax on State NOL	-	-	-
28	Total Mid-Tex Direct (Sum Ln 2 through Ln 27)	$ (270,604,182)	$ 56,818,698	$ (213,785,484)
29				
30	SSU - Customer Support:			
31	MIP/VPP Accrual	$ (1,089,339)	$ 1,089,339	$ -
32	Vacation Accrual	(7,857)	-	(7,857)
33	Worker's Comp Insurance Reserve	(30,934)	-	(30,934)
34	CWIP	(1,826,428)	1,826,428	-
35	Fixed Asset Cost Adjustment	(35,659,228)	-	(35,659,228)
36	Depreciation Adjustment	19,078,119	-	19,078,119
37	Clearing Account-Adjustment	268	-	268
38	Charitable Contribution Carryover	12,979	(12,979)	-
39	Prepayments	(418,652)	-	(418,652)
40	Intra Period Tax Allocation	318,090	-	318,090
41	Total Customer Support (Sum Ln 31 through Ln 40)	$ (19,622,982)	$ 2,902,788	$ (16,720,194)
42	Allocation to Mid-Tex	50.79%	50.79%	50.79%
43	SSU Customer Support Allocated to Mid-Tex (Ln 41 times Ln 42)	$ (9,966,513)	$ 1,474,326	$ (8,492,187)

ATMOS ENERGY CORP., MID-TEX DIVISION
BEGINNING BALANCE ACCUMULATED DEFERRED INCOME TAXES-ACCOUNTS 192/282/283 (1)
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Assets / (Liabilities) - Per Book Balances at 9/30/2010	Adjustments	Assets / (Liabilities) - Adjusted Balances at 9/30/10
	(a)	(b)	(c)	(d) = (b)+(c)
44				
45				
46	SSU - General Office:			
47	Director's Deferred Bonus	$ 231,108	$ -	$ 231,108
48	MIP/VPP Accrual	1,599,082	(1,599,082)	-
49	Miscellaneous Accrued	1,933	-	1,933
50	Self Insurance - Adjustment	3,229,158	(3,229,158)	-
51	Vacation Accrual	(5,325)	-	(5,325)
52	Worker's Comp Insurance Reserve	63,591	-	63,591
53	Rabbi Trust - True Up	4,279	(4,279)	-
54	SEBP Adjustment	24,006,958	(24,006,958)	-
55	Restricted Stock Grant Plan	6,678,304	-	6,678,304
56	Rabbi Trust	1,999,696	(1,999,696)	-
57	Excess Capital Loss over Capital Gain	577,361	-	577,361
58	Restricted Stock - MIP	3,198,052	(3,198,052)	-
59	Director's Stock Awards	2,432,802	-	2,432,802
60	Director's Stock - Temp	(678,829)	-	(678,829)
61	Pension Expense	(21,464,184)	-	(21,464,184)
62	FAS 106 Adjustment	5,129,749	-	5,129,749
63	CWIP	(3,286,754)	3,286,754	-
64	Fixed Asset Cost Adjustment	(16,282,799)	-	(16,282,799)
65	Depreciation Adjustment	(4,494,600)	-	(4,494,600)
66	Section 481(a) Cushion Gas	556,809	(556,809)	-
67	Section 481(a) Line Pack Gas	67,557	(67,557)	-
68	IRS Audit Assessment - Cost	1,874,769	(1,874,769)	-
69	IRS Audit Assessment - Accum	(516,058)	516,058	-
70	PGA - Amended Item	11,175,101	(11,175,101)	-
71	Amortization - LGS Acq. 1810.13523	(39,717)	39,717	-
72	Deferred Expense Projects	12,473	-	12,473
73	UNICAP IRS Audit	1,521,591	-	1,521,591
74	Allowance for Doubtful Accounts	2	-	2
75	Clearing Account-Adjustment	18,492	-	18,492
76	Charitable Contribution Carryover	208,565	(208,565)	-
77	Prepayments	(1,276,910)	-	(1,276,910)
78	Inventory Adjustment	46,902	-	46,902
79	Stock Option Expense	322,795	-	322,795
80	Tax Free Interest - Temp	935,790	-	935,790
81	Federal & State Tax Interest	(372,865)	-	(372,865)
82	Prepayments - IRS Audits	759,088	-	759,088
83	Regulatory Liability-Atmos 109	14,490	-	14,490
84	Intra Period Tax Allocation	(318,090)	-	(318,090)
85	FD - NOL Credit Carryforward - Utility	224,409,076	-	224,409,076
86	FD - NOL Credit Carryforward - Non Reg	(183,148,944)	183,148,944	-
87	FD - FAS 115 Adjustment	(2,469,538)	-	(2,469,538)
88	FD - Treasury Lock Adjustment	3,211,056	-	3,211,056
89	FD - FAS 158 Measure Date Change	4,573,142	-	4,573,142
90	FD - AMT Minimum Tax Credit	14,396,280	-	14,396,280
91	Total SSU General Office (Sum Ln 47 through Ln 90)	$ 78,901,439	$ 139,071,445	$ 217,972,884
92	Allocation to Mid-Tex	37.60%	37.60%	37.60%
93	SSU General Office Allocated to Mid-Tex (Ln 91 times Ln 92)	$ 29,666,941	$ 52,290,863	$ 81,957,804
94				
95	Total SSU ADIT Allocated to Mid-Tex (Ln 43 plus Ln 93)	$ 19,700,428	$ 53,765,189	$ 73,465,618
96				
97	Total ADIT Direct and Allocated (Ln 28 plus Ln 95)	$ (250,903,754)	$ 110,583,888	$ (140,319,866)

ATMOS ENERGY CORP., MID-TEX DIVISION
OPERATION AND MAINTENANCE EXPENSES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	FERC Acct (a)	Description (b)	Per Book Amount (c)	Adjustments (d)	Adjusted Amount (e)=(c)+(d)
1	841	Natural gas storage - Operation labor and expenses	$ 541	$ -	$ 541
2	870	Operation Supervision and Engineering	3,723,408	58,597	3,782,005
3	871	Distribution Load Dispatching	1,079,083	16	1,079,099
4	872	Compressor Station Labor and Expenses	-	-	-
5	874	Mains and Services Expenses	29,855,483	250,054	30,105,537
6	875	Measuring and Regulating Station Expenses - General	56,752	1,487	58,239
7	876	Measuring and Regulating Station Expenses - Industrial	3,144	39	3,183
8	877	Measuring and Regulating Station Exp. - City Gate Chk. Sta.	3,555	41	3,596
9	878	Meter and House Regulator Expenses	3,195,727	91,128	3,286,855
10	879	Customer Installations Expenses	687,955	19,936	707,891
11	880	Other Expenses	5,497,746	18,323	5,516,069
12	881	Rents	94,514	-	94,514
13	885	Maintenance Supervision and Engineering	5,921	-	5,921
14	886	Maintenance of Structures and Improvements	24,022	-	24,022
15	887	Maintenance of Mains	1,254,039	22,577	1,276,616
16	888	Maintenance of compressor station equipment	2,647	-	2,647
17	889	Maint. of Measuring and Regulating Station Equip. - General	2,226,188	53,423	2,279,612
18	890	Maint. of Measuring and Regulating Station Equip. - Industrial	2,082	61	2,143
19	891	Maint. of Measuring and Regulating Station Equip. - City Gate	1,340	39	1,379
20	892	Maintenance of Services	468,347	2,010	470,357
21	893	Maintenance of Meters and House Regulators	236,382	6,430	242,812
22	894	Maintenance of Other Equipment	799,265	5,771	805,036
23	895	Maintenance of Other Equipment	-	-	-
24	901	Supervision	179	5	184
25	902	Meter Reading Expense	7,677,976	184,544	7,862,520
26	903	Customer Records and Collection Expenses	15,033,007	45,145	15,078,152
27	904	Uncollectible Accounts	1,184,734	2,404,398	3,589,132
28	905	Miscellaneous Customer Accounts Expenses	100	-	100
29	907	Supervision	-	-	-
30	908	Customer Assistance Expenses	1,088,839	(1,000,000)	88,839
31	909	Informational and Instructional Advertising Expenses	4,920	-	4,920
32	910	Miscellaneous Customer Service and Informational Expenses	2,532,478	29,350	2,561,828
33	911	Supervision	3,540	-	3,540
34	912	Demonstrating and Selling Expenses	57,677	-	57,677
35	913	Advertising Expenses	2,011,210	(25,420)	1,985,790
36	916	Miscellaneous Sales Expenses	395	(375)	20
37	920	Administrative and General Salaries	4,231,063	131,145	4,362,208
38	921	Office Supplies and Expenses	373,361	(154,075)	219,286
39	922	Administrative Expenses Transferred - Credit	45,719,872	(1,683,096)	44,036,776
40	923	Outside Services Employed	1,547,865	(397,682)	1,150,183
41	924	Property Insurance	602,533	137,371	739,904
42	925	Injuries and Damages	1,833,288	(526,536)	1,306,752
43	926	Employee Pensions and Benefits	13,412,405	2,790,397	16,202,802
44	928	Regulatory Commission Expenses	-	-	-
45	929	Duplicate Charges - Credit	-	-	-
46	930.1	General Advertising Expenses	5,203	-	5,203
47	930.2	Miscellaneous General Expense	590,730	(291,782)	298,948
48	931	Rents	836,378	-	836,378
49	932	Maintenance of General Plant	662	-	662
50					
51		Total Operation and Maintenance Expenses (Sum Ln 1 through Ln 49)	$ 147,966,556	$ 2,173,320	$ 150,139,876

ATMOS ENERGY CORP., MID-TEX DIVISION
ADJUSTMENTS TO OPERATION AND MAINTENANCE EXPENSES
TEST YEAR ENDING SEPTEMBER 30, 2011

ATMOS ENERGY CORP.
ADJUSTMENTS TO OPERATION AI
TEST YEAR ENDING SE

Line No.	FERC Account	Account Description	Base Labor	Medical and Dental Benefits	Pensions and Retiree Medical Benefits	Property Insurance	Injuries and Damages	Employee Expense	SSU Service-Level Factors	Miscellaneous Adjustments	Uncollectible Expense
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	841	Natural gas storage - Operation labor and expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	870	Operation Supervision and Engineering	61,594	-	-	-	-	-	-	(2,197)	-
3	871	Distribution Load Dispatching	16	-	-	-	-	-	-	-	-
4	872	Compressor Station Labor and Expenses	-	-	-	-	-	-	-	-	-
5	874	Mains and Services Expenses	250,060	-	-	-	-	-	-	(6)	-
6	875	Measuring and Regulating Station Expenses - General	1,487	-	-	-	-	-	-	-	-
7	876	Measuring and Regulating Station Expenses - Industrial	39	-	-	-	-	-	-	-	-
8	877	Measuring and Regulating Station Exp. - City Gate Chk. Sta.	41	-	-	-	-	-	-	-	-
9	878	Meter and House Regulator Expenses	91,128	-	-	-	-	-	-	-	-
10	879	Customer Installations Expenses	19,936	-	-	-	-	-	-	-	-
11	880	Other Expenses	28,058	-	-	-	-	-	-	(9,498)	-
12	881	Rents	-	-	-	-	-	-	-	-	-
13	885	Maintenance Supervision and Engineering	-	-	-	-	-	-	-	-	-
14	886	Maintenance of Structures and Improvements	-	-	-	-	-	-	-	-	-
15	887	Maintenance of Mains	22,577	-	-	-	-	-	-	-	-
16	888	Maintenance of compressor station equipment	-	-	-	-	-	-	-	-	-
17	889	Maint. of Measuring and Regulating Station Equip. - General	53,535	-	-	-	-	-	-	(112)	-
18	890	Maint. of Measuring and Regulating Station Equip. - Industrial	61	-	-	-	-	-	-	-	-
19	891	Maint. of Measuring and Regulating Station Equip. - City Gate	39	-	-	-	-	-	-	-	-
20	892	Maintenance of Services	2,010	-	-	-	-	-	-	-	-
21	893	Maintenance of Meters and House Regulators	6,430	-	-	-	-	-	-	-	-
22	894	Maintenance of Other Equipment	5,771	-	-	-	-	-	-	-	-
23	895	Maintenance of Other Equipment	-	-	-	-	-	-	-	-	-
24	901	Supervision	5	-	-	-	-	-	-	-	-
25	902	Meter Reading Expense	184,675	-	-	-	-	-	-	(131)	-
26	903	Customer Records and Collection Expenses	45,145	-	-	-	-	-	-	-	-
27	904	Uncollectible Accounts	-	-	-	-	-	-	-	-	2,404,398
28	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-
29	907	Supervision	-	-	-	-	-	-	-	-	-
30	908	Customer Assistance Expenses	-	-	-	-	-	-	-	-	-
31	909	Informational and Instructional Advertising Expenses	-	-	-	-	-	-	-	-	-
32	910	Miscellaneous Customer Service and Informational Expenses	65,036	-	-	-	-	-	-	(33,356)	-
33	911	Supervision	-	-	-	-	-	-	-	-	-
34	912	Demonstrating and Selling Expenses	-	-	-	-	-	-	-	-	-
35	913	Advertising Expenses	39,457	-	-	-	-	-	-	(64,877)	-
36	916	Miscellaneous Sales Expenses	-	-	-	-	-	-	-	(375)	-
37	920	Administrative and General Salaries	131,145	-	-	-	-	-	-	-	-
38	921	Office Supplies and Expenses	-	-	-	-	-	-	-	(154,075)	-
39	922	Administrative Expenses Transferred - Credit	1,173,613	387,054	1,016,859	(1,420)	-	(157,168)	(3,781,913)	(319,389)	-
40	923	Outside Services Employed	-	-	-	-	-	-	-	(397,682)	-
41	924	Property Insurance	-	-	-	137,371	-	-	-	-	-
42	925	Injuries and Damages	-	-	-	-	600,000	-	-	(1,126,536)	-
43	926	Employee Pensions and Benefits	-	783,919	1,810,987	-	-	[redacted]	-	195,491	-
44	928	Regulatory Commission Expenses	-	-	-	-	-	-	-	-	-
45	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-
46	930.1	General Advertising Expenses	-	-	-	-	-	-	-	-	-
47	930.2	Miscellaneous General Expense	-	-	-	-	-	(240,494)	-	-	-
48	931	Rents	-	-	-	-	-	-	-	-	-
49	932	Maintenance of General Plant	-	-	-	-	-	-	-	-	-
50											
51		Total Adjustments to Operation and Maintenance Expenses	$ 2,181,858	$ 1,170,973	$ 2,827,846	$ 135,951	$ 600,000	$ (397,662)	$ (3,781,913)	$ (1,912,744)	$ 2,404,398

., MID-TEX DIVISION
ND MAINTENANCE EXPENSES
:PTEMBER 30, 2011

Line No.	FERC Account	Account Description	Rule Compliance	Customer Conservation Program	Total Adjustments
	(a)	(b)	(l)	(m)	(n)
1	841	Natural gas storage - Operation labor and expenses	$ -	$ -	$ -
2	870	Operation Supervision and Engineering	(800)	-	58,597
3	871	Distribution Load Dispatching	-	-	16
4	872	Compressor Station Labor and Expenses	-	-	-
5	874	Mains and Services Expenses	-	-	250,054
6	875	Measuring and Regulating Station Expenses - General	-	-	1,487
7	876	Measuring and Regulating Station Expenses - Industrial	-	-	39
8	877	Measuring and Regulating Station Exp. - City Gate Chk. Sta.	-	-	41
9	878	Meter and House Regulator Expenses	-	-	91,128
10	879	Customer Installations Expenses	-	-	19,936
11	880	Other Expenses	(237)	-	18,323
12	881	Rents	-	-	-
13	885	Maintenance Supervision and Engineering	-	-	-
14	886	Maintenance of Structures and Improvements	-	-	-
15	887	Maintenance of Mains	-	-	22,577
16	888	Maintenance of compressor station equipment	-	-	-
17	889	Maint. of Measuring and Regulating Station Equip. - General	-	-	53,423
18	890	Maint. of Measuring and Regulating Station Equip. - Industrial	-	-	61
19	891	Maint. of Measuring and Regulating Station Equip. - City Gate	-	-	39
20	892	Maintenance of Services	-	-	2,010
21	893	Maintenance of Meters and House Regulators	-	-	6,430
22	894	Maintenance of Other Equipment	-	-	5,771
23	895	Maintenance of Other Equipment	-	-	-
24	901	Supervision	-	-	5
25	902	Meter Reading Expense	-	-	184,544
26	903	Customer Records and Collection Expenses	-	-	45,145
27	904	Uncollectible Accounts	-	-	2,404,398
28	905	Miscellaneous Customer Accounts Expenses	-	-	-
29	907	Supervision	-	-	-
30	908	Customer Assistance Expenses	-	(1,000,000)	(1,000,000)
31	909	Informational and Instructional Advertising Expenses	-	-	-
32	910	Miscellaneous Customer Service and Informational Expenses	(2,330)	-	29,350
33	911	Supervision	-	-	-
34	912	Demonstrating and Selling Expenses	-	-	-
35	913	Advertising Expenses	-	-	(25,420)
36	916	Miscellaneous Sales Expenses	-	-	(375)
37	920	Administrative and General Salaries	-	-	131,145
38	921	Office Supplies and Expenses	-	-	(154,075)
39	922	Administrative Expenses Transferred - Credit	(732)	-	(1,683,096)
40	923	Outside Services Employed	-	-	(397,682)
41	924	Property Insurance	-	-	137,371
42	925	Injuries and Damages	-	-	(526,536)
43	926	Employee Pensions and Benefits	-	-	2,790,397
44	928	Regulatory Commission Expenses	-	-	-
45	929	Duplicate Charges - Credit	-	-	-
46	930.1	General Advertising Expenses	-	-	-
47	930.2	Miscellaneous General Expense	(51,288)	-	(291,782)
48	931	Rents	-	-	-
49	932	Maintenance of General Plant	-	-	-
50					-
51	Total Adjustments to Operation and Maintenance Expenses		$ (55,387)	$ (1,000,000)	$ 2,173,320

ATMOS ENERGY CORP., MID-TEX DIVISION
BASE LABOR ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description (a)	Shared Services - Customer Support Employees (b)	Shared Services - General Office Employees (c)	Shared Services - Total (3) (d)	Mid-Tex Direct Employees (e)	Total Adjustment (f)
1	Annualized October 2011 Employee Salaries (1), (5)	$ 27,218,609	$ 35,658,661	$ 62,877,270	$ 87,434,446	
2						
3	Test Year Base Labor Per Book (5)	25,594,277	34,476,309	60,070,586	84,883,392	
4						
5	Base Labor Adjustment Total (Ln 1 minus Ln 3)	$ 1,624,332	$ 1,182,352	$ 2,806,684	$ 2,551,054	
6						
7	Allocation to Mid-Tex (2)	50.79%	37.60%	45.23%	84.58%	
8						
9	Allocated Base Labor Adjustment (Ln 5 times Ln 7)	$ 824,998	$ 444,564	$ 1,269,563	$ 2,157,625	
10						
11	O&M Expense Factor (2)	89.60%	97.72%	92.44%	46.73%	
12						
13	Test Year Base Labor O&M Expense Adjustment (Ln 9 times Ln 11)	$ 739,202	$ 434,411	$ 1,173,613	$ 1,008,245	
14						
15	Adjustment Summary:					
16	Account 922	$ 739,202	$ 434,411	$ 1,173,613	$ -	$ 1,173,613
17	Other O&M Accounts (4)	-	-	-	1,008,245	1,008,245
18	Total (Ln 16 plus Ln 17)	$ 739,202	$ 434,411	$ 1,173,613	$ 1,008,245	$ 2,181,858
19						

20 Notes:
21 1. Annual salaries are base labor only and do not include items such as overtime and bonuses.
22 2. Shared Services based on FY12 factors, adjusted to the four-factor formula including Operating Income. The four-factor formula calculation does not include the states of
23 Iowa, Illinois and Missouri. Mid-Tex factors are based upon actual test year ratios.
24 3. The factors in Col.(d) are a calculation derived from the totals of Customer Support and General Office and are only used in the calculation
25 of other employee-related adjustments.
26 4. Distribution by account is based upon per book O&M test year labor (See Page 2).
27 5. SSU amounts exclude cost centers which do not allocate to Mid-Tex and employee time charged below the line for rate making purposes.

ATMOS ENERGY CORP., MID-TEX DIVISION
BASE LABOR ADJUSTMENT - DISTRIBUTION OF MID-TEX DIRECT BY FERC ACCOUNT
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	FERC Account	Account Description	Per Book O&M Labor	Ratio of Labor by Account	Base Labor Adjustment Allocated by Account (4)
	(a)	(b)	(c)	(d)	(e)=(c)x(d)
1	870	Operation Supervision and Engineering	$ 2,113,517	6.1090%	$ 61,594
2	871	Distribution Load Dispatching	558	0.0016%	16
3	872	Compressor Station Labor and Expenses	-	0.0000%	-
4	874	Mains and Services Expenses	8,580,415	24.8012%	250,060
5	875	Measuring and Regulating Station Expenses - General	51,037	0.1475%	1,487
6	876	Measuring and Regulating Station Expenses - Industrial	1,340	0.0039%	39
7	877	Measuring and Regulating Station Exp. - City Gate Chk. Sta.	1,391	0.0040%	41
8	878	Meter and House Regulator Expenses	3,126,968	9.0383%	91,128
9	879	Customer Installations Expenses	684,098	1.9773%	19,936
10	880	Other Expenses	962,795	2.7829%	28,058
11	887	Maintenance of Mains	774,721	2.2393%	22,577
12	889	Maint. of Meas. and Reg. Sta. Equip. - Gen.	1,836,999	5.3097%	53,535
13	890	Maint. of Meas. and Reg. Sta. Equip. - Ind.	2,082	0.0060%	61
14	891	Maint. of Meas. and Reg. Sta. Equip. - City Gate	1,340	0.0039%	39
15	892	Maintenance of Services	68,978	0.1994%	2,010
16	893	Maintenance of Meters and House Regulators	220,651	0.6378%	6,430
17	894	Maintenance of Other Equipment	198,040	0.5724%	5,771
18	901	Supervision	179	0.0005%	5
19	902	Meter Reading Expense	6,336,908	18.3165%	184,675
20	903	Customer Records and Collection Expenses	1,549,112	4.4776%	45,145
21	905	Miscellaneous Customer Accounts Expenses	-	0.0000%	-
22	910	Miscellaneous Customer Service and Informational Expenses	2,231,651	6.4505%	65,036
23	911	Supervision	-	0.0000%	-
24	912	Demonstrating and Selling Expenses	-	0.0000%	-
25	913	Advertising Expenses	1,353,919	3.9134%	39,457
26	920	Administrative and General Salaries	4,500,108	13.0073%	131,145
27	921	Office Supplies and Expenses	-	0.0000%	-
28	923	Outside Services	-	0.0000%	-
29	Total	(Sum Ln 1 through Ln 28)	$ 34,596,807	100.00%	$ 1,008,245

ATMOS ENERGY CORP., MID-TEX DIVISION
MEDICAL AND DENTAL BENEFITS ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Shared Services	Mid-Tex Direct	Total Adjustment
	(a)	(b)	(c)	(d)
1	FY12 Projected Expense per Employee (1)	$ 10,985	$ 10,985	
2				
3	Number of Employees at End of Test Period	1,042	1,669	
4				
5	Sub-Total (Ln 1 times Ln 3)	$ 11,446,306	$ 18,333,862	
6				
7	Test Year Medical and Dental Cost	10,520,669	16,350,395	
8				
9	Medical and Dental Cost Adjustment (Ln 5 minus Ln 7)	$ 925,637	$ 1,983,467	
10				
11	Mid-Tex Allocation Factor (2)	45.23%	84.58%	
12				
13	Allocated Medical and Dental Cost Adjustment (Ln 9 times Ln 11)	$ 418,698	$ 1,677,572	
14				
15	Labor Expense Factor (2)	92.44%	46.73%	
16				
17	Test Year Medical and Dental Expense Adjustment (Ln 13 times Ln 15)	$ 387,054	$ 783,919	
18				
19	Adjustment Summary:			
20	Account 922	$ 387,054	$ -	$ 387,054
21	Account 926	-	783,919	783,919
22	Total (Ln 20 plus Ln 21)	$ 387,054	$ 783,919	$ 1,170,973

ATMOS ENERGY CORP., MID-TEX DIVISION
PENSIONS AND RETIREE MEDICAL BENEFITS ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

		Shared Services			Mid-Tex Direct			
Line No.	Description	Pension Account Plan ("PAP")	Supplemental Executive Benefit Plan ("SEBP/SERP")	Post-Retirement Medical Plan ("FAS 106")	Pension Account Plan ("PAP")	Supplemental Executive Benefit Plan ("SERP")	Post-Retirement Medical Plan ("FAS 106")	Adjustment Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Fiscal Year 2012 Towers Watson Report (1), (4)	[redacted]						
2	Test Year Amounts (4)	[redacted]			6,659,714	148,346	6,702,524	
3	Test Year Change for Actuarially Determined Benefit Costs (Ln 1 minus Ln 2)	$ 1,724,089	[redacted]	$ 707,718	$ 2,902,524	$ (4,956)	$ 1,683,813	
4	Allocation to Mid-Tex (2) (3)	45.23%	[redacted]	45.23%	84.58%	100.00%	84.58%	
5	Test Year Change for Actuarially Determined Benefit Costs Allocated to Mid-Tex (Ln 3 times Ln 4)	$ 779,866	$ -	$ 320,126	$ 2,454,889	$ (4,956)	$ 1,424,132	
6	O&M Expense Factor (2) (3)	92.44%	[redacted]	92.44%	46.73%	33.42%	46.73%	
7	Test Year Adjustment for Actuarially Determined Benefit Costs (Ln 5 times Ln 6)	$ 720,927	$ -	$ 295,932	$ 1,147,155	$ (1,656)	$ 665,488	
8								
9	Adjustment Summary:							
10	Account 922	$ 720,927	$ -	$ 295,932	$ -	$ -	$ -	$ 1,016,859
11	Account 926	-	-	-	1,147,155	(1,656)	665,488	1,810,987
12	Total (Ln 10 plus Ln 11)	$ 720,927	$ -	$ 295,932	$ 1,147,155	$ (1,656)	$ 665,488	$ 2,827,846
13							$ 7,092,975	

ATMOS ENERGY CORP., MID-TEX DIVISION
PROPERTY INSURANCE ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Shared Services General Office	Shared Services Customer Support	Mid-Tex Direct	Total Adjustment
	(a)	(b)	(c)	(d)	(e)
1	Premium Adjustment:				
2	Annual Premium - Current Policy (CY 2011)	$ 131,809	$ 157,445	$ 2,138,571	
3	Less: Test Year Premium Amount	137,150	164,961	2,143,042	
4	Subtotal (Ln 2 minus Ln 3)	$ (5,341)	$ (7,516)	$ (4,471)	
5	Allocation to Mid-Tex (1)	37.60%	50.79%	100.00%	
6	Allocated Total Adjustment (Ln 4 times Ln 5)	$ (2,008)	$ (3,817)	$ (4,471)	
7	O&M Expense Factor (1)	41.51%	84.50%	27.00%	
8	Premium Adjustment (Ln 6 times Ln 7)	$ (833)	$ (3,226)	$ (1,207)	
9					
10	Cancellation Fee Adjustment:				
11	Amortization of Cancellation Fee (2)	$ 16,909	$ -	$ 138,578	
12	Less: Test Year Cancellation Fee	-	-	-	
13	Subtotal (Ln 11 minus Ln 12)	$ 16,909	$ -	$ 138,578	
14	Allocation to Mid-Tex (1)	37.60%	50.79%	100.00%	
15	Allocated Total Adjustment (Ln 13 times Ln 14)	$ 6,358	$ -	$ 138,578	
16	O&M Expense Factor (1)	41.51%	84.50%	100.00%	
17	Cancellation Fee Adjustment (Ln 15 times Ln 16)	$ 2,639	$ -	$ 138,578	
18					
19	Total Property Insurance Adjustment (Ln 8 plus Ln 17)	$ 1,806	$ (3,226)	$ 137,371	
20					
21	Summary by Account:				
22	Account 922	$ 1,806	$ (3,226)	$ -	$ (1,420)
23	Account 924	-	-	137,371	137,371
24	Totals (Ln 22 plus Ln 23)	$ 1,806	$ (3,226)	$ 137,371	$ 135,951

ATMOS ENERGY CORP., MID-TEX DIVISION
INJURIES AND DAMAGES ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	FERC Account	Per Book Amount	Amortized Amount (1)	Adjustment Amount
	(a)	(b)	(c)	(d)	(e) = (d)-(c)
1	Mid-Tex:				
2	Reserve accrual for Cleburne incident		$ -	$ 200,000	
3	Reserve accrual for Wylie incident		-	$ 200,000	
4	Reserve accrual for Lutrell incident		-	$ 200,000	
5	Mid-Tex Total (Sum Ln 2 through Ln 4)	925	$ -	$ 600,000	$ 600,000
6					
7	Shared Services:				
8	No Adjustment Required	922	$ -	$ -	$ -
9					
10	Total Adjustment to Non-Labor O&M (Ln 5 plus Ln 8)				$ 600,000
11					
12					
13	Note:				
14	1. Cleburne, Wylie and Lutrell incidents are amortized over 5 years.				

ATMOS ENERGY CORP., MID-TEX DIVISION
EMPLOYEE EXPENSE ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Shared Services - Customer Support	Shared Services - General Office	Mid-Tex Direct	Total Adjustment
	(a)	(b)	(c)	(d)	(e)
1	Fiscal Year Ending September 30, 2011:				
2	Employee Expense Adjustment	$ 73,728	$ 317,271	$ 235,845	
3	Adjustment to align Oct10-May11 with GUD10000 (1)	1,021	17,914	4,650	
4	Subtotal (Ln 2 plus Ln 3)	$ 74,749	$ 335,186	$ 240,494	
5	Mid-Tex Allocation Factor (2) (3)	50.79%	37.60%	100.00%	
6					
7	Allocated Employee Expense Totals (Ln 4 times Ln 5)	$ 37,965	$ 126,030	$ 240,494	
8	Expense Factor (2) (3)	89.60%	97.72%	100.00%	
9	Total Employee Expense Removal, FY 2011 (Ln 7 times Ln 8)	$ 34,017	$ 123,151	$ 240,494	$ 397,662
10					
11	Summary by Account				
12	Account 922	$ (34,017)	$ (123,151)	$ -	$ (157,168)
13	Account 930.2	-	-	(240,494)	(240,494)
14	Total (Ln 12 plus Ln 13)	$ (34,017)	$ (123,151)	$ (240,494)	$ (397,662)
15					

16 Notes:
17 1. An estimate was calculated to align the employee expense review for October 2010 through May 2011 with the changes in
18 guidelines ordered in GUD 10000, specifically limiting meals to $25, lodging to $150.
19 2. See WP_F-2.1, Col (b) and Col (c), Ln 7 and Ln 11, as applicable, for the Shared Services factors, as adjusted.
20 3. Mid-Tex costs are directly charged and not allocated.

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") SERVICE-LEVEL FACTORS ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

R

Line No.	Description	Per Book SSU O&M (Labor)	Per Book SSU O&M (Non-Labor)	Total Per Book SSU O&M Exp	FY12 Capitalization Rate (Labor Exp)	FY12 Capitalization Rate (Non-Labor Exp)	Four-Factor Allocation Factor (2), (3)	Total	SSU Allocated to Capital (4)	Expense Allocated to Mid-Tex
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f)	(g)	(h) = (d) * (g)	(i) = sum(b*g*e) + sum(c*g*f)	(j) = (h) - (i)
1	1001 SS Dallas Executive Chairman	$ 832,062	$ 1,920,642	$ 2,752,704	58.49%	58.49%	37.60%	$ 1,035,017	$ 605,428	$ 429,589
2	1101 SS Dallas Chief Financial Officer	457,000	834,783	1,291,783	58.49%	58.49%	37.60%	485,711	284,114	201,597
3	1105 SS Dallas Audit	-	3,488,965	3,488,965	0.00%	0.00%	37.60%	1,311,851	-	1,311,851
4	1106 SS Dallas Treasurer	155,504	170,089	325,593	59.08%	59.08%	37.60%	122,423	72,330	50,093
5	1107 SS Dallas Treasury	393,250	821,243	1,214,493	58.49%	58.49%	37.60%	456,649	267,115	189,535
6	1108 SS Dallas Risk Management	457,893	419,860	877,753	80.00%	80.00%	37.60%	330,035	264,028	66,007
7	1110 SS Dallas Procurement	89,148	122,460	211,609	49.25%	50.75%	38.72%	81,935	41,065	40,870
8	1111 SS Dallas Purchasing	301,039	175,219	476,258	56.41%	56.41%	38.72%	184,407	104,031	80,376
9	1112 SS Dallas Mail & Supply	21,123	477,291	498,414	15.21%	17.11%	38.72%	192,986	32,872	160,114
10	1114 SS Dallas Vice Pres & Controller	223,852	294,062	517,914	24.97%	24.97%	37.60%	194,736	48,624	146,112
11	1116 SS Dallas Taxation	183,914	521,460	705,374	5.70%	5.70%	37.60%	265,221	15,118	250,103
12	1117 SS Dallas Acctg Services	142,163	188,566	330,729	49.68%	49.68%	37.60%	124,354	61,773	62,581
13	1118 SS Dallas Supply Chain	214,819	159,106	373,926	40.26%	40.26%	38.72%	144,784	58,292	86,492
14	1119 SS Dallas General Accounting	549,046	311,628	860,674	58.49%	58.49%	37.60%	323,613	189,296	134,317
15	1120 SS Dallas Accounts Payable	537,939	321,577	859,515	16.54%	16.54%	37.60%	323,178	53,443	269,735
16	1121 SS Dallas Plant Accounting	489,915	236,180	726,095	90.00%	90.00%	37.60%	273,012	245,711	27,301
17	1123 SS Dallas Gas Accounting	272,744	235,816	508,560	0.00%	25.56%	38.72%	196,914	23,334	173,580
18	1125 SS Dallas Financial Reporting	713,419	633,491	1,346,909	0.00%	0.00%	37.60%	506,438	-	506,438
19	1126 SS Dallas Payroll	516,330	343,323	859,653	58.49%	58.49%	37.60%	323,229	189,071	134,158
20	1128 SS Dallas Property & Sales Tax	1,043,135	749,053	1,792,188	6.88%	6.88%	37.60%	673,863	46,328	627,535
21	1129 SS Dallas Income Tax	428,793	243,143	671,936	2.00%	2.00%	37.60%	252,648	5,053	247,595
22	1130 SS Dallas Business Planning and Analysis	465,043	367,789	832,832	53.12%	53.12%	37.60%	313,145	166,347	146,797
23	1132 SS Dallas Investor Relations (5)	372,354	649,871	1,022,224	0.00%	0.00%	0.00%	-	-	-
24	1133 SS Dallas Corporate Communications	673,076	1,686,486	2,359,562	0.00%	0.00%	37.60%	887,195	-	887,195
25	1134 SS Dallas IT	1,098,220	1,212,216	2,310,436	46.43%	57.14%	37.60%	868,724	452,182	416,542
26	1135 SS Dallas IT Application Support	1,664,097	4,153,020	5,817,118	11.50%	23.04%	37.60%	2,187,236	431,788	1,755,448
27	1137 SS Dallas IT Operations	1,807,635	6,048,319	7,855,954	26.96%	30.00%	37.60%	2,953,839	865,466	2,088,373
28	1139 SS Dallas IT Telecommunications	245,609	1,033,046	1,278,654	36.84%	40.00%	37.60%	480,774	189,393	291,381
29	1141 SS Dallas Gas Purchase Accounting	424,553	186,974	611,526	0.00%	0.00%	45.38%	277,511	-	277,511
30	1144 SS Dallas Rate Administration	731,828	320,801	1,052,629	0.00%	5.03%	45.38%	477,683	7,326	470,358
31	1145 SS Dallas Revenue Accounting	310,432	165,593	476,025	0.00%	19.05%	45.38%	216,020	14,318	201,702
32	1146 SS Dallas IT Enterprise Solutions	646,346	407,911	1,054,257	46.32%	74.50%	37.60%	396,401	226,824	169,577
33	1150 SS Dallas Strategic Planning	344,750	485,093	829,842	53.57%	53.57%	37.60%	312,021	167,154	144,867
34	1153 SS Dallas Distribution Acctg	63,692	24,616	88,308	0.00%	6.53%	45.38%	40,074	729	39,345

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") SERVICE-LEVEL FACTORS ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

R

Line No.	Description	Per Book SSU O&M (Labor)	Per Book SSU O&M (Non-Labor)	Total Per Book SSU O&M Exp	FY12 Capitalization Rate (Labor Exp)	FY12 Capitalization Rate (Non-Labor Exp)	Four-Factor Allocation Factor (2), (3)	Total	SSU Allocated to Capital (4)	Expense Allocated to Mid-Tex
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f)	(g)	(h) = (d) * (g)	(i) = sum(b*g*e) + sum(c*g*f)	(j) = (h) - (i)
35	1154 SS Dallas Rates & Regulatory	1,613,120	1,124,019	2,737,139	60.86%	60.86%	38.72%	1,059,820	644,960	414,860
36	1155 SS Dallas Texas Gas Pipeline Accounting	-	1,701	1,701	0.00%	0.00%	0.00%	-	-	-
37	1156 SS Dal - IT Customer Svc Support	796,106	1,314,005	2,110,111	25.00%	70.00%	50.79%	1,071,725	568,254	503,472
38	1158 SS CCC IT Support	357,513	2,596,846	2,954,359	5.47%	13.57%	50.79%	1,500,519	188,929	1,311,590
39	1159 SS Dallas Director Technical Training	85,988	358,055	444,043	0.00%	0.00%	38.72%	171,933	-	171,933
40	1161 SS Dallas Benefits and Payroll Accounting	238,128	83,826	321,954	58.49%	58.49%	37.60%	121,055	70,810	50,244
41	1165 SS Dallas IT Production Services & Support	439,506	271,270	710,776	14.00%	38.57%	37.60%	267,252	62,477	204,774
42	1171 SS Regulatory Accounting Services	243,071	85,483	328,554	60.86%	60.86%	38.72%	127,216	77,418	49,798
43	1201 SS Dallas President & CEO	752,877	1,548,880	2,301,757	58.49%	58.49%	37.60%	865,460	506,247	359,214
44	1203 SS Amarillo Customer Support Center	6,179,890	4,119,295	10,299,184	15.50%	15.50%	50.79%	5,230,956	810,767	4,420,188
45	1209 SS Dallas Safety & Compliance	159,146	278,268	437,413	0.00%	0.00%	38.72%	169,366	-	169,366
46	1210 SS Waco Customer Support Center	8,430,578	5,208,051	13,638,629	15.50%	15.50%	50.79%	6,927,059	1,073,653	5,853,406
47	1212 SS CSC-Customer Contact Management	-	679,268	679,268	15.50%	15.50%	50.79%	345,000	53,473	291,527
48	1213 SS Dallas Quality Assurance	1,355,287	511,614	1,866,901	0.00%	0.00%	50.79%	948,199	-	948,199
49	1214 SS Dallas Workforce Management	416,818	231,261	648,079	0.00%	0.00%	50.79%	329,159	-	329,159
50	1215 SS Dispatch Operations	2,353,494	955,341	3,308,836	15.50%	15.50%	50.79%	1,680,558	260,477	1,420,081
51	1225 SS Dallas Regulated Operations	139,732	81,278	221,011	73.94%	89.49%	50.79%	112,251	89,420	22,831
52	1226 SS Dallas Customer Service	782,075	684,163	1,466,238	0.00%	0.00%	50.79%	744,702	-	744,702
53	1227 SS Dallas Customer Program Management	894,578	1,195,631	2,090,209	41.07%	41.07%	50.79%	1,061,617	436,032	625,585
54	1228 SS Dallas Customer Revenue Management	2,309,972	1,838,970	4,148,942	0.00%	0.00%	50.79%	2,107,248	-	2,107,248
55	1401 SS Dallas Employment & Employee Relations	629,253	506,767	1,136,019	0.00%	0.00%	38.72%	439,867	-	439,867
56	1402 SS Dallas Executive Compensation	-	275,897	275,897	0.00%	0.00%	37.60%	103,737	-	103,737
57	1403 SS Dallas Human Resources - Vice Pres	515,684	613,818	1,129,502	58.49%	58.49%	37.60%	424,693	248,422	176,271
58	1405 SS Dallas Compensation & Benefits	760,287	836,122	1,596,409	0.00%	0.00%	38.72%	618,130	-	618,130
59	1407 SS Dallas Facilities	450,996	779,031	1,230,027	36.00%	36.00%	37.60%	462,490	166,496	295,994
60	1408 SS Dallas Employee Development	974,070	1,294,085	2,268,156	0.00%	0.00%	37.60%	852,827	-	852,827
61	1410 SS Dallas Corporate Development	65,365	(205,885)	(140,519)	0.00%	0.00%	37.60%	(52,835)	-	(52,835)
62	1414 SS Tech Training Delivery	752,600	793,330	1,545,930	0.00%	0.00%	38.72%	598,584	-	598,584
63	1415 SS Tech Training Prog & Curriculum	170,489	69,753	240,243	0.00%	0.00%	38.72%	93,022	-	93,022
64	1420 SS Dallas EAPC	-	53,212	53,212	0.00%	0.00%	37.60%	20,008	-	20,008
65	1463 SS HR Benefit Variance	-	101,642	101,642	15.21%	17.11%	37.60%	38,217	6,541	31,677
66	1501 SS Corporate Legal	1,907,448	2,112,894	4,020,342	41.87%	41.87%	37.60%	1,511,648	632,920	878,729
67	1502 SS Corporate Secretary	122,764	1,690,307	1,813,071	0.00%	0.00%	37.60%	681,715	-	681,715
68	1503 SS Corporate Governmental Affairs	309,105	334,227	643,332	0.00%	0.00%	38.72%	249,098	-	249,098
69	1504 SS Corporate Central Records	76,132	407,479	483,611	58.49%	58.49%	38.72%	187,254	109,533	77,721

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") SERVICE-LEVEL FACTORS ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

R

Line No.	Description	Per Book SSU O&M (Labor)	Per Book SSU O&M (Non-Labor)	Total Per Book SSU O&M Exp	FY12 Capitalization Rate (Labor Exp)	FY12 Capitalization Rate (Non-Labor Exp)	Four-Factor Allocation Factor (2), (3)	Total	SSU Allocated to Capital (4)	Expense Allocated to Mid-Tex
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f)	(g)	(h) = (d) * (g)	(i) = sum(b*g*e) + sum(c*g*f)	(j) = (h) - (i)
70	1505 SS Corporate Gas Contract Administration	127,307	103,518	230,825	0.00%	0.00%	38.72%	89,375	-	89,375
71	1508 SS Corporate Energy Assistance	299,811	262,494	562,305	0.00%	0.00%	45.38%	255,174	-	255,174
72	1821 SS Gas Supply Executive	276,895	193,156	470,051	0.00%	0.00%	38.52%	181,064	-	181,064
73	1822 SS Dallas-Regional Gas Supply	146,698	85,079	231,777	0.00%	0.00%	82.89%	192,120	-	192,120
74	1823 SS Dallas Gas Contract Admin	316,789	143,266	460,056	0.00%	0.00%	38.72%	178,133	-	178,133
75	1825 SS Franklin-Gas Control & Storage	223,677	122,312	345,989	0.00%	0.00%	0.00%	-	-	-
76	1826 SS New Orleans Gas Supply & Service	46,560	268,071	314,631	0.00%	0.00%	45.38%	142,780	-	142,780
77	1827 SS Regional Supply Planning	218,877	158,314	377,191	0.00%	0.00%	0.00%	-	-	-
78	1828 SS Jackson-West Region Gas Supply & Services	86,771	70,116	156,887	0.00%	0.00%	0.00%	-	-	-
79	1829 SS Franklin-East Region Gas Supply & Services	-	41,405	41,405	0.00%	0.00%	0.00%	-	-	-
80	1831 SS Dallas Gas Supply	94,046	71,991	166,036	0.00%	0.00%	100.00%	166,036	-	166,036
81	1832 SS Dallas-Supply Planning	-	10,182	10,182	0.00%	0.00%	100.00%	10,182	-	10,182
82	1833 SS Dallas-Corporate Gas Supply Risk Mgmt	89,205	63,108	152,314	0.00%	0.00%	45.38%	69,120	-	69,120
83	1835 SS Franklin Gas Control	675,531	498,883	1,174,415	0.00%	0.00%	0.00%	-	-	-
84	1836 SS TBS-System Support	222,529	130,714	353,244	0.00%	0.00%	38.52%	136,069	-	136,069
85	1837 SS TBS-Application Support	669,681	280,670	950,351	0.00%	0.00%	38.52%	366,075	-	366,075
86	1838 SS TBS-Technical Support	421,726	226,005	647,731	0.00%	0.00%	38.52%	249,506	-	249,506
87	1839 SS TBS-Transportation & Scheduling	194,829	81,832	276,661	0.00%	0.00%	38.52%	106,570	-	106,570
88	1901 SS Dallas Employee Relocation Exp (Div 02) (6)	188,262	329,832	518,094	0.00%	0.00%	37.60%	194,803	-	194,803
89	1901 SS Dallas Employee Relocation Exp (Div 12) (6)	82,001	27,880	109,881	0.00%	0.00%	50.79%	55,809	-	55,809
90	1903 SS Dallas Controller - Miscellaneous (1)	-	(3,349)	(3,349)	0.00%	0.00%	37.60%	(1,259)	-	(1,259)
91	1904 SS Dallas Performance Plan (5)	-	5,569,561	5,569,561	36.30%	36.30%	0.00%	-	-	-
92	1905 SS Outside Director Retirement Cost	-	1,415,134	1,415,134	0.00%	0.00%	37.60%	532,091	-	532,091
93	1908 SS Dallas SEBP (5)	-	8,072,404	8,072,404	0.00%	58.49%	0.00%	-	-	-
94	1910 SS Dallas Overhead Capitalized (4)	-	(38,579,953)	(38,579,953)	0.00%	0.00%	40.54%	-	-	-
95	1913 SS Dallas Fleet Management	310,589	122,892	433,481	49.35%	49.35%	38.72%	167,844	82,832	85,011
96	1915 SS Dallas Insurance	-	11,415,475	11,415,475	0.00%	58.49%	37.60%	4,292,218	2,510,712	1,781,506
97	TOTAL (Sum Ln 1 through Ln 96)	$ 55,844,579	$ 53,420,588	$ 109,265,167				$ 55,666,887	$ 13,728,928	$ 41,937,959
98										
99	Allocated Shared Services O&M to Mid-Tex Division									45,719,872
100										
101	Total Adjustment to Account 922 (Ln 97 minus Ln 99)									$ (3,781,913)
102										

103 Notes:
104 1. $(4,087,701) of Cost Center 1903 was not allocated during the test period, The per book amount to allocate has been increased by this amount.
105 2. Factors are displayed only if applicable to Mid-Tex.
106 3. Based on FY12 factors, adjusted to the four-factor formula including Operating Income. The four-factor formula calculation does not include the states of Iowa, Illinois and Missouri.
107 4. The Total represents the amount that would be credited from Cost Center 1910.
108 5. Allocation percentages have been set to zero to align with GUD 9869 for cost centers 1132, 1904 and 1908. Cost center 1350 is no longer active. All costs in cost center 1507 are below the line.
109 6. Cost center 1901 expenses have been divided between General Office (Div 002) and Customer Support (Div 012) and separately allocated.

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") COST CENTER FUNCTIONS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Division (1) (a)	Cost Center/Description (b)	Cost Center Function (c)
1	002	1001 SS Dallas Chairman & CEO	Costs associated with the Chairman, President and CEO
2	002	1101 SS Dallas Chief Financial Officer	Costs associated with the CFO
3	002	1105 SS Dallas Audit	Costs associated with Internal Audit services provided by KPMG
4	002	1106 SS Dallas Treasurer	Costs associated with the VP, Treasurer who manages Treasury, Procurement and Risk Management. The Treasurer supports the overall financing needs of the Company for both O&M and capital projects.
5	002	1107 SS Dallas Treasury	Costs associated with treasury operations
6	002	1108 SS Dallas Risk Management	Costs associated with insurance and risk management
7	002	1110 SS Dallas Procurement	Costs with associated with purchasing and mail room activities
8	002	1111 SS Dallas Purchasing	Costs associated with procurement activities
9	002	1112 SS Dallas Mail & Supply	Costs associated with mail services at the Dallas corporate office
10	002	1114 SS Dallas Vice Pres & Controller	Costs associated with the VP, Controller
11	002	1116 SS Dallas Taxation	Costs associated with management of Income Tax and Property & Sales Tax departments
12	002	1117 SS Dallas Acctg Services	Costs associated with management of General Accounting, Accounts Payable, Plant Accounting and Payroll departments
13	002	1118 SS Dallas Supply Chain	Costs associated with inventory management
14	002	1119 SS Dallas General Accounting	Costs associated with maintaining the general books and records of the Company
15	002	1120 SS Dallas Accounts Payable	Costs associated with the processing and payment of the Company's bills
16	002	1121 SS Dallas Plant Accounting	Costs associated with the recordkeeping for the Company's fixed assets
17	002	1123 SS Dallas Gas Accounting	Costs associated with the management of Gas Purchase Accounting, Revenue Accounting and Rate Administration departments
18	002	1125 SS Dallas Financial Reporting	Costs associated with the preparation and distribution of both internal and external reporting
19	002	1126 SS Dallas Payroll	Costs associated with paying the Company's employees
20	002	1128 SS Dallas Property & Sales Tax	Costs associated with the management and handling of the Company's property and sales tax activities
21	002	1129 SS Dallas Income Tax	Costs associated with the processing of the Company's income taxes
22	002	1130 SS Dallas Business Planning and Analysis	Costs associated with the planning and budgeting activities of the Company
23	002	1132 SS Dallas Investor Relations	Performs a number of significant activities directly related to attracting capital investment and maintaining important relationships with the investing community. Such activities include, but are not limited to: 1.) Accompanying executive management at all discussions with the investing public and financial press to maintain compliance with SEC Regulation FD, applicable to all publicly trade companies. 2.) Initiating, building and maintaining relationships with the financial analyst community and individual investors, as well as serving as the first point of contact between the Company and institutional and individual investors. 3.) Preparing and presenting financial presentations throughout the year as needed and overseeing the issuance of financial press releases at least four times per year to report and explain the financial performance of the Company. 4.) Keeping executive management apprised of investor opinions and concerns. 5.) Reviewing research reports submitted by analysts and providing accurate feedback to foster reporting accuracy. 6.) Maintaining knowledge of other companies that are considered to be Atmos Energy's peers. 7.) Providing management and the Company's Board of Directors with information regarding developments in the financial markets and perceptions of investors that may have use in formulating the Company's long and short-term practices and policies. 8.) Serving on the Company's 7-member Financial Information Committee to review all SEC filings to ensure appropriate and accurate disclosures are made. 9.) Providing input and guidance on the design and production of the annual report to shareholders. 10.) Overseeing the Stock Transfer Agent's administration of the Company's Direct Stock Purchase Plan and Dividend Reinvestment Plan, as well as ongoing plan redesign to ensure best practices. Providing investors with reliable, comprehensive information about the Company is a critical step in attracting equity investment capital. This information may be especially important in attracting non-institutional equity investors who do not have access to the range of analysts' reports, and attracting such investment has both near-term and longer-term direct benefits to the Company. The near-term benefits result from rising equity prices, which immediately translate to lower cost common equity, and ultimately ratemaking benefits through lower rates. For example, increased investment and higher equity prices lowers the yield calculation, as shown in the common Discounted Cash Flow formulation of the cost of capital. In a similar vein, the longer-term benefits derive from providing lower cost equity to maintain and expand the utility system.

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") COST CENTER FUNCTIONS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Division (1) (a)	Cost Center/Description (b)	Cost Center Function (c)
24	002	1133 SS Dallas Corporate Communications	Costs associated with internal and external corporate communications including the annual report to shareholders.
25	002	1134 SS Dallas IT	Costs associated with the VP, CIO who manages all IT functions
26	002	1135 SS Dallas IT Application Support	Costs associated with the maintenance and support of the Company's information systems (software)
27	002	1137 SS Dallas IT Operations	Costs associated with the maintenance and support of the Company's data center. Purpose is to provide operational services including the network operations center, data center operations, helpdesk, desktop support and security administration. The cost center supports hardware maintenance and software maintenance (for infrastructure items).
28	002	1139 SS Dallas IT Telecommunications	Costs associated with the negotiation and management of Telcom contracts and services including data and voice networks, long distance, maintenance of phone switches, cell phones, and management of radio licenses. This cost center was created to provide greater visibility into the costs of telecommunication services. This cost center tracks activities related to the management of office phones and mobile phones as well as fees to service providers such as AT&T. These activities were previously performed in each departments individual cost centers.
29	002	1141 SS Dallas Gas Purchase Accounting	Costs associated with the accounting for the utility's gas purchases
30	002	1144 SS Dallas Rate Administration	Costs associated with filing PGA, tariffs and recovering gas costs
31	002	1145 SS Dallas Revenue Accounting	Costs associated with the accounting for the utility's revenues
32	002	1146 SS Dallas IT Enterprise Solutions	Project management office for IT projects. To develop and deploy new software technical solutions to the Company. Costs in this center include internal and contractor labor, business systems projects, planning and overseeing development of IT projects and hardware and software.
33	002	1150 SS Dallas Strategic Planning	Costs associated with the VP, Strategic Planning who manages Business Planning & Analysis and Rates
34	002	1153 SS Dallas Distribution Acctg	Costs associated with gas accounting for the Mid-Tex Division
35	002	1154 SS Dallas Rates & Regulatory	Costs associated with rate case and regulatory work. Purpose is to manage the Company's rate strategy for regulated rates as well as the rate and regulatory activity for Atmos' twelve state operating area. The primary activity is the establishment of base rates through rate cases or formula ratemaking mechanisms. The department currently has approximately twenty-eight base rate case filings or formula mechanisms to manage in order to effect rate changes in its various jurisdictions as well as numerous monthly, quarterly and annual reports to meet reporting requirements.
36	002	1155 SS Dallas Texas Gas Pipeline Acctg	Costs associated with accounting for the Texas Gas Pipeline System
37	012	1156 SS Dal-IT Customer Svc Support	Costs associated with resources focusing on supporting Customer Service technologies
38	012	1158 SS CCC IT Support	Costs associated with supporting the IT activities in the Customer Contact Centers. Supports both the Amarillo and Waco customer contact centers, providing telephone and IT support for our contact centers. Costs in this center include labor and related expenses, hardware maintenance and software maintenance for call center equipment and software, and telephone access charges (not long distance).
39	002	1159 SS Dallas Director Technical Training	Costs associated with the planning, development and management of the Company's technical training activities. Provides oversight of technical training for the regulated divisions of the Company. Costs in this center include labor and related expenses plus the technical training materials given to students. The new Technical Training Organization provides safety training including the recent DOT mandated Operator Qualification training to all of the utility employees for Atmos Energy. The technical training for all Atmos utility divisions, including Mid-Tex, is now managed from the Shared Services organization.
40	002	1161 SS Dallas Benefits & Payroll Acctg	Costs associated with management of payroll and benefits departments
41	002	1165 SS Dallas IT Production Services & Support	Costs associated with providing direction for the production and support of all enterprise systems including supporting apps like Advantage and the Oracle Financial / HR system. This cost center was created to provide greater visibility into the costs of supporting existing computer applications. This cost center tracks activities related to management and quality assurance.
42	002	1171 SS Dallas Regulatory Accounting	Costs associated with regulatory accounting work on rate cases, special studies and other Commission requests. This cost center was created to clearly identify personnel who devote their time to working on the regulatory accounting side of the business on rate cases, special studies, and other commission requests such as documenting the Company's cost allocation methodologies.
43	002	1201 SS Dallas President & COO	Costs associated with the SVP, Utility Operations
44	012	1203 SS Amarillo Customer Support Center	Costs associated with the operations of the Customer Support Center
45	002	1209 SS Dallas Safety & Compliance	Costs associated with the VP, Security & Compliance
46	012	1210 SS Waco Customer Support Center	Costs associated with the operations of the Customer Support Center
47	012	1212 SS CSC-Customer Contact Management	Costs associated with both the Waco and Amarillo Customer Support Centers that are not specifically assigned to either support center.

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") COST CENTER FUNCTIONS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Division (1) (a)	Cost Center/Description (b)	Cost Center Function (c)
48	012	1213 SS Dallas Quality Assurance	Costs associated with monitoring calls to ensure customers are given correct information and that the correct processes and procedures are followed.
49	012	1214 SS Dallas Workforce Management	Costs associated with forecasting call volume and scheduling agents to ensure we have people available to answer calls
50	012	1215 SS Dispatch Operations	Service Orders to Service techs for emergency calls and same day service. To alert first responders of emergency situations and to communicate service order information to the approximately 750 service technicians throughout the regulated divisions. Costs in this center include the labor and related expenses to staff the dispatch function twenty-four hours a day as well as building maintenance and telecom costs.
51	012	1225 SS Dallas Regulated Operations	Costs of management for coordination of enterprise-wide utility operations projects
52	012	1226 SS Dallas Customer Service	Costs of management and administration of customer service organization (revenue management, customer contact and program development). Includes overall CSO management and administration, Regulated Operations initiatives and CSO human resources. CSO management and CSO human resources provide support to the contact centers as well as other CSO departments.
53	012	1227 SS Dallas Customer Program Management	Costs of managing ongoing customer service measurement, quality assurance, continuous improvements and resolution of escalated customer complaints. Purpose is the continuous improvement function within customer service. The group monitors customer satisfaction including the ongoing customer survey to identify opportunities for improvement. The Customer Program Management group also performs user acceptance testing on changes to customer systems to help ensure functional requirements are met.
54	012	1228 SS Dallas Customer Revenue Management	Costs associated with managing customer revenue functions of Payment Applications, Billing, Billing Systems and Collections. This cost center is for the Director of Revenue Management and the Energy Assistance Program Specialist. The director is responsible for the centers of Payment Applications (1109), Billing Services (1115), Revenue System Support (1148) and Collections (1200). These centers provide day-to-day support and transaction processing for customers in all states served by Atmos. Also, the coordination in all 12 states of Atmos' energy assistance programs is overseen in this area.
55	002	1401 SS Dallas Employment & Employee Relations	Costs associated with recruiting, union negotiations, and maintenance of HR employee data base. Purpose is to develop, implement and administer employment related activities for the enterprise including: employee relations, labor relations, human resource management systems, corporate compliance, AA/EEO and all other components of employment. Costs charged to this cost center include labor and related expenses, software maintenance, professional association dues, contract labor, legal fees and professional reference books. These costs are a necessary component to providing human resource services to our employees and as such are reasonable and necessary to the provision of safe and reliable service.
56	002	1402 SS Dallas Executive Compensation	Costs associated with the compensation committee of the Board of Directors. Costs incurred for executive compensation work for the Human Resources Committee of the Atmos Energy Board of Directors. Also included are costs related to corporate officer annual physical exams paid by the Company. These costs are a necessary component of providing human resource services to the corporate officers that are necessary for the provision of safe and reliable service.
57	002	1403 SS Dallas Human Resources - Vice Pres	Costs associated with the VP, Human Resources
58	002	1405 SS Dallas Compensation & Benefits	Costs associated with the management of the Company's compensation and benefit plans. The purpose is to ensure Atmos provides its employees the most cost effective pay and benefit plans that are 1) competitive within the utility sector and general industry overall, and 2) consistently applied to all nonunion employees regardless of where they work, unless the union has bargained for these benefits. Specifically, this cost center is accountable for: Group Medical Plan and Retiree Medical Plan; Group Dental Plan; Employee Assistance Plan; Group Life Insurance Plan; Optional Life Insurance Coverage (Group Variable Universal Life, Dependent Spouse and Child(ren)); Flexible Benefits Plan; Business Travel & Accident Insurance; Service Awards Program; Two Defined Contribution Plans (DC); Two Defined Benefit Plans (DB); The Master Trust (holds assets of the two DB plans); Taxable and Tax Exempt VEBA Trusts; Pension Payments to 1,500 retirees; Collection of Retiree Medical Contributions; Workers' Compensation; Group Long-Term Disability Plan; Short-Term Disability; Family Medical Leave; and Compensation Administration (Executive and Non-Executive). Costs specifically charged to this cost center are: Compensation and Benefits Costs for employees assigned
59			to this cost center; Service Awards Program for Shared Services; Compensation Consulting Costs and Compensation Surveys; Training Costs for assigned employees; and Business Travel and Accident Insurance Policy for all of Atmos. These costs are a necessary component to providing human resource services to our employees and as such are reasonable and necessary to the provision of safe and reliable service.
60	002	1407 SS Dallas Facilities	Costs associated with the management of the Company's facilities (offices)

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") COST CENTER FUNCTIONS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Division (1) (a)	Cost Center/Description (b)	Cost Center Function (c)
61	002	1408 SS Dallas Employee Development	Costs associated with designing, developing and implementing training and development opportunities for all employees in areas of customer service, leadership, culture shaping and communication. All training and development costs including those that go into the development and delivery of training programs or participant manuals go into this cost center. This cost center also provides training and development support to both customer support centers and all divisions.
62	002	1410 SS Dallas Corporate Development	Costs associated with developing and implementing a strategy to identify and evaluate opportunities to grow the Company both internally and externally.
63	002	1414 SS Tech Training Delivery	Costs associated with technical training delivery
64	002	1415 SS Tech Training Prog & Curriculum	Costs associated with the technical training curriculum and program development
65	002	1420 SS Dallas EAPC	Costs associated with the Shared Services Employee Activities Planning Committee (EAPC). This committee organizes various Dallas employee-related team building activities throughout the year, including the Company's Lincoln Center United Way campaign. This includes meals incurred by the EAPC as well as office supplies and materials. This does not include employee compensation for their work on the EAPC. These costs are a necessary component to providing human resource services to our employees and as such are reasonable and necessary to the provision of safe and reliable service.
66	002	1463 SS HR Benefit Variance	Used to accumulate the differences between the actual cost of employee benefits and the budgeted benefits rate
67	002	1501 SS Dallas Legal	Costs associated with the VP, General Counsel
68	002	1502 SS Dallas Corporate Secretary	Costs associated with the Corporate Secretary and the Board of Directors. Costs such as Director's fees, board meeting expenses, proxy solicitation expenses and NYSE fees are recorded in this cost center.
69	002	1503 SS Dallas Governmental Affairs	Costs associated with governmental relations

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") COST CENTER FUNCTIONS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Division (1) (a)	Cost Center/Description (b)	Cost Center Function (c)
70	002	1504 SS Dallas Central Records	Costs associated with the storage and maintenance of Company records
71	002	1505 SS Dallas Gas Contract Admin	Costs associated with maintaining and administrating the Company's gas contracts
72	002	1508 SS Corporate Energy Assistance	Planning, organizing, developing, monitoring and overseeing all aspects of the company's new Energy Assistance and Customer Advocacy Program. The focus of the program will be on meeting the needs of the company's low-income, elderly and disabled customers by working with help agencies across the enterprise to secure federal and state funding for bill payments and home weatherization
73	002	1821 SS Gas Supply Executive	Costs associated with the VP, Gas Supply
74	002	1822 SS Dallas-Regional Gas Supply	Costs associated with the management of the Regional Supply department
75	002	1823 SS Dallas Gas Contract Admin	Costs associated with maintaining and administrating the Company's gas contracts
76	002	1825 SS Franklin-Gas Control & Storage	Costs associated with the Manager of Gas Control for all areas excluding Mid-Tex
77	002	1826 SS New Orleans Gas Supply & Services	Costs associated with the Director of all the Gas Supply, Planning & Hedging departments.
78	002	1827 SS Regional Supply Planning	Costs associated with the management of the Regional Supply Planning department except for Mid-Tex
79	002	1828 SS Jackson-West Region Gas Supply & Services	Costs associated with the management of the Jackson Gas Supply and Services department
80	002	1829 SS Franklin-East Region Gas Supply & Services	Costs associated with the management of the Franklin Gas Supply and Services department. Region includes KY/Mid-States
81	002	1831 SS Dallas Gas Supply	Costs associated with the management of the Gas Supply department
82	002	1832 SS Dallas-Supply Planning	Costs associated with the management of the Gas Supply Planning department
83	002	1833 SS Dallas-Corporate Gas Supply Risk Mgmt	Costs associated with the management of the Hedging Administration for all regions. The timing of the fixed physical purchases, and support for fixed purchase plans are services provided by this cost center.
84	002	1835 SS Franklin Gas Control	Costs associated with operating the gas control system in Franklin Tennessee for all areas excluding Mid-Tex
85	002	1836 SS TBS-System Support	Software platform organization utilized to capture gas supply transactions including purchases and transportation activities. To provide support for the Transportation Billing System ("TBS") applications and related processes. The TBS Suite enables divisions to perform gas scheduling and complex billing functions for transportation and industrial sales customers, and provides support for those systems. Cost Center 1836 is the overall management of the TBS group. Costs in these centers include Company labor and related expenses as well as software maintenance fees, contract labor and tools to support the TBS system application.
86	002	1837 SS TBS-Application Support	User interface support including training for the TBS system. To provide support for the Transportation Billing System ("TBS") applications and related processes. The TBS Suite enables divisions to perform gas scheduling and complex billing functions for transportation and industrial sales customers, and provides support for those systems. Cost Center 1837 is the application support group that works with end users and is also responsible for loading contract change data into the application. Costs in these centers include Company labor and related expenses as well as software maintenance fees, contract labor and tools to support the TBS system application.
87	002	1838 SS TBS-Technical Support	Provide technical support for the TBS suite. To provide support for the Transportation Billing System ("TBS") applications and related processes. The TBS Suite enables divisions to perform gas scheduling and complex billing functions for transportation and industrial sales customers, and provides support for those systems. Cost Center 1838 is the Technical Support group which is responsible for polling all of the electronic meters as well as providing programming support to the TBS application. Costs in these centers include Company labor and related expenses as well as software maintenance fees, contract labor and tools to support the TBS system application.
88	002	1839 SS TBS-Transportation & Scheduling	Provide transportation, nomination & scheduling services to the divisions using TBS; to provide support for the Transportation Billing System ("TBS") applications and related processes. The TBS Suite enables divisions to perform gas scheduling and complex billing functions for transportation and industrial sales customers, and provides support for those systems. Cost Center 1839 is the Scheduling Group for the Atmos Utility Divisions. Costs in these centers include Company labor and related expenses as well as software maintenance fees, contract labor and tools to support the TBS system application.
89	002/012	1901 SS Dallas Employee Relocation Exp	Used to accumulate costs associated with the relocation of employees to Shared Services. Charges include transportation of household goods, closing costs, incidentals, etc.
90	002	1903 SS Dallas Controller – Misc.	Used to accumulate costs which do not specifically relate to another SS Cost Center
91	002	1904 SS Dallas Performance Plan	Costs of the Management Incentive Plan ("MIP") and Variable Payment Plan ("VPP") for individuals in Shared Service Cost Centers. The two plans are intended to provide the Company a means by which it can engender and sustain a sense of personal commitment on the part of its employees (through the VPP) and its executives and senior managers (through the MIP) in the continued growth, development, and financial success of the Company and encourage them to remain with and devote their best efforts to the business of the Company, thereby advancing the interests of the Company and its shareholders. Accordingly, the Company may award to employees, executives and senior managers the respective annual incentive compensation.

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") COST CENTER FUNCTIONS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Division (1) (a)	Cost Center/Description (b)	Cost Center Function (c)
92	002	1905 SS Outside Director Retirement	Cost Accrued retirement costs for the non-employee members of the Board of Directors. Cost associated with the annual grant of share units to non-employee directors for their service on the Board of Directors. Like all publicly held corporations, Atmos has a board of directors, and the activities of the board benefit the Company and its customers as a whole. These directors require compensation. Part of the compensation package includes annual grants of shares of the Company's stock. The expense recorded in this cost center is not invoiced from a third-party. Rather, it is calculated in accordance with the provisions of Statement of Financial Accounting Standard No. 123(R), Accounting for Stock-Based Compensation. Essentially, this standard requires shared-based compensation to be recognized over the requisite service period. The amount of the compensation cost recorded in this cost center is based upon the number of shares granted and the grant date fair value of the stock award.
93	002	1908 SS Dallas SEBP	Atmos Energy Corporation has implemented and maintained over the past years a supplemental executive retirement plan as an integral part of its executive compensation program. There are currently three SERP plans in which active corporate officers participate. The SEBP is currently closed to new membership; only employees promoted to or directly appointed to a Management Committee level job are eligible to join the SERP. An account based SERP is now in place to which newly appointed corporate officers are eligible. The SERP has been instrumental in helping the Company to attract, motivate, and retain a high quality senior management team responsible for the leadership of the Atmos organization.
94			To capture the cost associated with these plans, Cost Center 1908 has been established. Annuity benefits from the SEBP and SERP are funded through Rabbi Trusts maintained at State Street Trust and lump sum benefits from the SEBP, SERP and Account Based SERP are paid from Corporate assets. Atmos Energy's Company-Owned Life Insurance (COLI) which is a funding vehicle for benefits paid to former officers who receive an annuity benefit paid out of Corporate assets. The COLI reimburses Atmos for these annuity benefits. The SFAS 87 expense related to these annuity benefits is charged to the respective division where the former Corporate officer retired. The SFAS 87 expense for current retired SEBP and SERP participants, the management committee and current active Corporate officers is also accounted for in Cost Center 1908. The SFAS 87 expense for the SEBP and SERP is actuarially determined by an independent third-party actuary in accordance with SFAS 87.
95			The COLI policies were executed on certain executives (now retired) in prior years and are being phased out. Currently, no new policies are being executed. Finally, this Cost Center is used to record the independent actuary's cost to perform the annual SFAS 87 and SFAS 106 calculations required for Atmos Energy's SEC filings. This includes third-party costs associated with the administration of the SEBP (Haynes Boone, State Street, Towers Watson, LCG Associates). These costs are part of the overall executive compensation plan and are not incentive compensation.
96	002	1910 SS Dallas Overhead Capitalized	Represents the portion of Shared Services that is capitalized through the overhead pool throughout the year. Capitalization rates are based on estimated support of capital activities by each cost center.
97	002	1913 SS Dallas Fleet Management	Costs associated with managing Atmos' vehicle fleet
98	002	1915 SS Dallas Insurance	Used for booking property insurance costs related to Shared Services.
99			

100 Note:
101 1. Division 002 represents the General Office and Division 012 represents Customer Support.

ATMOS ENERGY CORP., MID-TEX DIVISION
MISCELLANEOUS ADJUSTMENTS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Footnote Reference	FERC Account	Amounts	Adjustment Amount
	(a)	(b)	(c)	(d)	(e)
	Miscellaneous Adjustments Mid-Tex				
1	Accrual of Lutrell reserve liability	(1)	925	$ (1,000,000)	
2	Expenses incurred in various proceedings	(2)	923	(846,278)	
3	Contract Labor Insourcing	(3)	923	(23,366)	
4	Lutrell Incident Expenses	(1)	923	471,962	
5	Lutrell Incident Expenses	(1)	925	(125,000)	
6	Pension and Other Postemployment Benefits Regulatory Asset Amortization	(6)	926	195,491	
7	900 Account Review	(5)	910	(26,920)	
8	900 Account Review	(5)	913	(47,918)	
9	900 Account Review	(5)	916	(375)	
10	5400 Account Review	(4)	870	(2,197)	
11	5400 Account Review	(4)	874	(6)	
12	5400 Account Review	(4)	880	(9,498)	
13	5400 Account Review	(4)	889	(112)	
14	5400 Account Review	(4)	902	(131)	
15	5400 Account Review	(4)	910	(6,437)	
16	5400 Account Review	(4)	913	(16,959)	
17	5400 Account Review	(4)	921	(154,075)	
18	5400 Account Review	(4)	925	(1,536)	
19	Total (Sum Ln 1 through Ln 18)			$ (1,593,355)	
20					
21	Miscellaneous Adjustments Shared Services				
22	5400 Account Review General Office	(4)	922	$ (23,214)	
23	5400 Account Review Customer Service	(4)	922	(5,479)	
24	Contract Labor Insourcing	(3)	922	(17,339)	
25	900 Account Review General Office	(5)	922	(33,831)	
26	Amarillo Call Center Lease Termination	(7)	922	(208,742)	
27	SSU MIP/VPP in cost centers other than 1904	(8)	922	(15,099)	
28	SEBP in cost center 1402	(9)	922	(15,685)	
29	Total (Sum Ln 22 through Ln 28)			$ (319,389)	
30					
31	Total Miscellaneous Adjustments (Ln 19 plus Ln 28)				$ (1,912,744)

ATMOS ENERGY CORP., MID-TEX DIVISION
MISCELLANEOUS ADJUSTMENTS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Footnote Reference	FERC Account	Amounts	Adjustment Amount
	(a)	(b)	(c)	(d)	(e)
32					
33	Notes:				
34	1. The recording of the Lutrell incident $1 million liability and the expenses that exceed the $1 million liability, which are subject				
35	to insurance recovery.				
36	2. Expenses related to Company rate proceedings the Company reasonably expects to be recovered in other proceedings or				
37	did not seek recovery.				
38	3. Removal of contract labor expense for positions that were insourced by the end of the test year.				
39	4. O&M expenses recorded in sub accounts 05400-05499 and 7590 that are being voluntarily removed by the Company, and				
40	include items such as alcohol and meals greater than $25. Any adjustments in sub accounts 05415, 05416, 05417 and				
41	07510 are shown on WP_F-2.10.				
42	5. O&M expenses recorded to FERC accounts 905, 907-913, 916, 923-926, 928, 930.1, 930.2 and 932 that are being				
43	voluntarily removed by the Company and include items such as meals greater than $25, alcohol, other controversial				
44	items and non-recurring expenses.				
45	6. Adjustment to include the annual amortization of the Pension and Other Postemployment Benefits Regulatory Asset. Please see WP_B-7.				
46	7. Remove Amarillo Contact Center lease expense for the test year as the building was replaced by new construction.				
47	8. Remove MIP/VPP expense recorded to cost centers other than 1904 which is removed on WP_F-2.7.				
48	9. Remove SEBP expense recorded to cost centers other than 1908 which is removed on WP_F-2.7.				

ATMOS ENERGY CORP., MID-TEX DIVISION
UNCOLLECTIBLE EXPENSE ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	FERC Account	Per Books Amount	Adjusted Cost (1)	Adjustment Amount
	(a)	(b)	(c)	(d)	(e)
1	Total Uncollectible Expense	904	$ 1,184,734	$ 3,589,132	$ 2,404,398
2					
3					
4	Note:				
5	1. The calculation of the adjusted uncollectible expense is shown on Page 2.				

ATMOS ENERGY CORP., MID-TEX DIVISION
UNCOLLECTIBLE EXPENSE ADJUSTMENT CALCULATION FOR RIDER GCR PART A
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Calculated Amounts
	(a)	(b)
1	Proposed Total Revenue Requirement - Schedule A	$ 1,274,247,490
2	Per Book Uncollectible Experience Rate (1)	0.523%
3	Estimated Total Uncollectible Expense (Ln 1 times Ln 2) (2)	$ 6,665,300
4		
5	Proposed Revenue Requirement - Rider GCR Part A (3)	$ 588,090,591
6	Per Book Uncollectible Experience Rate (1)	0.523%
7	Estimated Uncollectible Expense - Rider GCR Part A (Ln 5 times Ln 6)	$ 3,076,169
8		
9	Proposed Uncollectible Expense excluding Rider GCR Part A Component (Ln 3 minus Ln 7)	$ 3,589,132
10		
11		
12	Notes:	
13	1. The experience rate was calculated using the 3-year average of actual net charge-offs, fiscal years 2009 through	
14	2011, the method established in GUD 9670 and used in GUD 9869.	
15	2. The estimated Uncollectible Expense on Ln 3 has been calculated using the method established in GUD 9670.	
16	3. The amount is from Cost of Service Schedule A, Page 2 of 2, Col. (e) Ln 2.	

ATMOS ENERGY CORP., MID-TEX DIVISION
RULE COMPLIANCE ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Rule (1)	FERC Account	Cost Center	Amount	Allocation Factor	Expense Factor	Total Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Mid-Tex:							
1	Nondeductible Dues/Donations	7.5414	870		$ (800)	100%		$ (800)
2	Nondeductible Dues/Donations	7.5414	874		-	100%		-
3	Nondeductible Dues/Donations	7.5414	880		(237)	100%		(237)
4	Nondeductible Dues/Donations	7.5414	910		(2,330)	100%		(2,330)
5	Nondeductible Dues/Donations	7.5414	912		-	100%		-
6	Nondeductible Dues/Donations	7.5414	913		-	100%		-
7	Nondeductible Dues/Donations	7.5414	921		-	100%		-
8	Nondeductible Dues/Donations	7.5414	930.2		(51,288)	100%		(51,288)
9	Nondeductible Dues/Donations	7.5414	931		-	100%		-
10	Total (Sum Ln 1 to Ln 9)				$ (54,655)			$ (54,655)
11								
12	Shared Services:							
13	Nondeductible Dues/Donations	7.5414	922	1128	$ (1,450)	37.60%	93.13%	$ (508)
14	Nondeductible Dues/Donations	7.5414	922	1154	(50)	38.72%	39.14%	(8)
15	Nondeductible Dues/Donations	7.5414	922	1203	(390)	50.79%	84.50%	(167)
16	Nondeductible Dues/Donations	7.5414	922	1501	(225)	37.60%	58.13%	(49)
17	Total (Sum Ln 13 to Ln 16)				$ (2,115)			$ (732)
18								
19	Total Rule Compliance (Ln 10 plus Ln 17)							$ (55,387)
20								
21	Notes:							
22	1. Expenses in the test year related to sub-accounts 05415, 05416, 05417 and 07510.							
23	2. In compliance with Rule No. 7.501, the Company advises that $526,719 expenses for Legislative Advocacy were recorded in Account 426.4 during							
24	calendar year 2009, and $542,007 recorded in fiscal year 2011.							

ATMOS ENERGY CORP., MID-TEX DIVISION
RULE COMPLIANCE, 7.5414, ADJUSTMENT CALCULATION FOR ADVERTISING LIMITATION
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description (a)	FERC Account (b)	Per Book Amount (1) (c)	Adjustment Amount (d)
1	Supervision	907	$ -	$ -
2	Customer Assistance Expenses	908	1,088,839	-
3	Informational and Instructional Advertising Expenses	909	4,920	-
4	Miscellaneous Customer Service and Informational Expenses	910	300,827	-
5	Supervision	911	3,540	-
6	Demonstrating and Selling Expenses	912	57,677	-
7	Advertising Expenses	913	657,291	-
8	Miscellaneous Sales Expenses	916	395	-
9	General Advertising Expenses	930.1	5,203	-
10				
11	Total Advertising (Sum of Ln 1 through Ln 9)		$ 2,118,693	$ -
12				
13	Total Operating Revenue	480-495	$ 1,192,606,763	
14	Less: Uncollectible Accounts	904	1,184,734	
15				
16	Total Gross Receipts (Ln 13 minus Ln 14)		$ 1,191,422,029	
17				
18	Allowable Percentage for Advertising per Substantive Rule 7.5414		0.500%	
19				
20	Calculated Allowable Advertising Expense (Ln 16 times Ln 18)		$ 5,957,110	
21				
22	Total Advertising Expense Per Book (Ln 11)		$ 2,118,693	
23				
24	Adjustment Amount (2)			$ -
25				
26				
27	Note:			
28	1. Per Book amount is net of per book labor.			
29	2. The above information is provided per Substantive Rule 7.5414. The advertising expense included in the rate filing			
30	is below the allowable level; consequently, an adjustment to expense is not required.			

ATMOS ENERGY CORP., MID-TEX DIVISION
CUSTOMER CONSERVATION PROGRAM ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Per Books Amount	Adjusted Costs	Adjustment Amount
	(a)	(b)	(c)	(d)
1	Total Conservation Program Costs	$ -	$ -	
2				
3	Less: Shareholder funding - Account 426.5 (1)	-	-	
4				
5	Customer Funded Program Costs - Account 908	$ 1,000,000	$ -	$ (1,000,000)
6				
7	Note:			
8	1. The Company is proposing that the Conservation program be collected through Rider CEE in the rate effective period.			

ATMOS ENERGY CORP., MID-TEX DIVISION
INCENTIVE COMPENSATION ADJUSTMENT
TEST YEAR ENDING SEPTEMBER 30, 2011

SCC-Exhibit 8
Page 1 of 1

Line No.	Description	Shared Services	Mid-Tex Employees Direct	Total Adjustment
	(a)	(b)	(c)	(d)
1	Management Incentive Plan (MIP) & Variable Pay Plan (VIP) (1)	$ -	$ (2,091,700)	
2				
3	Long Term Incentive Plan (LTIP & Restricted Stock Plan) (2)	(6,333,614)	(781,945)	
4				
5	Base Labor Adjustment Total	$ (6,333,614)	$ (2,873,645)	
6				
7	Allocation to Mid-Tex (3)	66.80%	100.00%	
8				
9	Allocated Base Labor Adjustment	$ (4,230,575)	$ (2,873,645)	
10				
11	O&M Expense Factor (3)	29.35%	28.72%	
12				
13	Test Year Base Labor O&M Expense	$ (1,241,636)	$ (825,291)	$ (2,066,927)
14				
15	Adjustment Summary:			
16	Account 922 (Ln. 13)	$ (1,241,636)	$ -	$ (1,241,636)
17	Account 926 (5)	-	(258,292)	(258,292)
18	Other O&M Accounts (5)	-	(566,999)	(566,999)
19	Total (Ln. 16 + Ln. 17 + Ln.18)	$ (1,241,636)	$ (825,291)	$ (2,066,927)
20				

Line No.				
21	Notes:			
22	1. Mid-Tex Direct Incentive Compensation:			
23		MIP/VPP	LTIP	Total
24	Total TY Accrual (5)	$ 2,091,700	$ 781,945	$ 2,873,645
25	Less: Capital (5)	(1,524,701)	(523,653)	(2,048,354)
26	O&M Expense	$ 566,999	$ 258,292	$ 825,291
27	% O&M	27.11%	33.03%	28.72%
28	Source: MIP/VPP per ATM RFIs 3-10 (Amended), Attachment 1.			
29	Source: LTIP per ATM RFIs 3-45, Attachment 1 & ACSC RFI 1-12, Attachment 1 (gross amounts only)			
30				
31	2. SSU Incentive Compensation:	Total SSU	MTX Alloc.	% Alloc. to
32		LTIP	LTIP	Mid-Tex
33	Total TY Accrual (5)	$ 6,333,614	$ 4,230,575	66.80%
34	Less: Capital (5)		(2,988,939)	
35	O&M Expense		$ 1,241,636	
36	% O&M		29.35%	
37	Source: ATM RFI 1-40, Attachment 1			
38	3. SSU and Pipeline factors are based upon actual test year ratios, see notes and 2.			
39	4. Distribution by account was based upon designations in responses to ATM RFIs 1-38 and 1-40.			
40	5. Source: SCC-Exhibit 8A, page 1			

(d) Distribution by account based on per book O&M test year labor (see Atmos Cost of Service WP_F-2.1).

FERC A/C	Account Description	Per Book O&M Labor	Ratio of Labor by Account	Adjustment Distribution
870	Operation Supervision and Engineering	$ 2,113,517	6.11%	$ (34,638)
871	Distribution Load Dispatching	558	0.00%	(9)
872	Compressor Station Labor and Expenses	-	0.00%	-
874	Mains and Services Expenses	8,580,415	24.80%	(140,622)
875	Measuring and Regulating Station Expenses - General	51,037	0.15%	(836)
876	Measuring and Regulating Station Expenses - Industrial	1,340	0.00%	(22)
877	Measuring and Regulating Station Exp. - City Gate Chk. Sta.	1,391	0.00%	(23)
878	Meter and House Regulator Expenses	3,126,968	9.04%	(51,247)
879	Customer Installations Expenses	684,098	1.98%	(11,212)
880	Other Expenses	962,795	2.78%	(15,779)
887	Maintenance of Mains	774,721	2.24%	(12,697)
889	Maint. of Meas. and Reg. Sta. Equip. - Gen.	1,836,999	5.31%	(30,106)
890	Maint. of Meas. and Reg. Sta. Equip. - Ind.	2,082	0.01%	(34)
891	Maint. of Meas. and Reg. Sta. Equip. - City Gate	1,340	0.00%	(22)
892	Maintenance of Services	68,978	0.20%	(1,130)
893	Maintenance of Meters and House Regulators	220,651	0.64%	(3,616)
894	Maintenance of Other Equipment	198,040	0.57%	(3,246)
901	Supervision	179	0.00%	(3)
902	Meter Reading Expense	6,336,908	18.32%	(103,854)
903	Customer Records and Collection Expenses	1,549,112	4.48%	(25,388)
905	Miscellaneous Customer Accounts Expenses	-	0.00%	-
910	Miscellaneous Customer Service & Informational Expenses	2,231,651	6.45%	(36,574)
911	Supervision	-	0.00%	-
912	Demonstrating and Selling Expenses	-	0.00%	-
913	Advertising Expenses	1,353,919	3.91%	(22,189)
920	Administrative and General Salaries	4,500,108	13.01%	(73,751)
921	Office Supplies and Expenses	-	0.00%	-
923	Outside Services	-	0.00%	-
Total		$ 34,596,807	100.00%	$ (566,999)

ATMOS ENERGY CORP., MID-TEX DIVISION
DEPRECIATION AND AMORTIZATION EXPENSE
BASED ON PLANT IN SERVICE AS OF SEPTEMBER 30, 2011

Line No.	Acct.	Description	Total Plant	Non-depreciable and Fully Depreciated Plant	Depreciable Plant	Rate	Proposed Depreciation Expense Total	Depreciation Expense Cleared to Capital
	(a)	(b)	(c)	(d)	(e)=(c)-(d)	(f)	(g)=(e)x(f)-(h)	(h)=(e)*(f)*cap rate
1	Mid-Tex:							
2		Distribution Plant						
3	374	Land	779,648	779,648	-	0.00%	-	
4	374	Land Rights	3,202,299		3,202,299	0.98%	31,383	
5	374	Land & Land Rights	-		-	1.15%	-	
6	375	Structures & Improvements	1,468,570		1,468,570	1.71%	25,113	
7	376.00	Mains-Cathodic Protection	136,850,221		136,850,221	1.85%	2,531,729	
8	376.01	Mains-Steel	429,197,678		429,197,678	3.97%	17,039,148	
9	376.02	Mains-Plastic	910,830,245		910,830,245	2.21%	20,129,348	
10	378	M&R Station Equipment - General	39,052,296		39,052,296	3.09%	1,206,716	
11	379	M&R Station Equipment - City Gate	5,513,898		5,513,898	1.88%	103,661	
12	380	Services	758,429,725		758,429,725	3.67%	27,834,371	
13	381	Meters	161,610,868		161,610,868	3.31%	5,349,320	
14	382	Meter Installations	113,850,895		113,850,895	3.66%	4,166,943	
15	383	House Regulators	47,352,660		47,352,660	3.50%	1,657,343	
16	385	Industrial M&R Station Equipment	1,280,593		1,280,593	2.80%	35,857	
17		Test Year End Plant Balance (Sum of Ln 3 through Ln 16)	$ 2,609,419,594	$ 779,648	$ 2,608,639,946	3.07%	$ 80,110,931	
18								
19		General Plant						
20	302	Franchises & Consents	$ 18,896	$ 18,896	$ -	0.00%	$ -	
21	303	Computer Software	3,386,331	3,386,331	-	0.00%	-	
22	389	Land	3,982,767	3,982,767	-	0.00%	-	
23	390	Structures & Improvements	29,710,016	-	29,710,016	2.54%	754,634	
24	390	Air Conditioning Equipment	147,233	-	147,233	2.75%	4,049	
25	391	Office Furniture & Equipment	6,459,687	-	6,459,687	4.00%	258,387	
26	392	Transportation Equipment	3,284,784	-	3,284,784	9.04%	296,944	
27	393	Stores Equipment	144,748	-	144,748	4.00%	1,563	4,227
28	394	Tools, Shop, and Garage Equipment	11,778,174	-	11,778,174	5.00%	159,005	429,903
29	395	Laboratory Equipment	329,367	-	329,367	10.00%	8,893	24,044
30	396	Power Oper. Tool & Work Equipment	2,267,102	-	2,267,102	7.24%	164,138	
31	397	Radio Communication Equipment	8,167,925	-	8,167,925	6.67%	544,801	
32	398	Miscellaneous Equipment	18,571,170	3,352,404	15,218,766	2.50%	380,469	
33	399	Other Tangible Property	-	-	-	14.29%	-	
34	399.01	Other Tangible Property-Servers Hardware	574,805	-	574,805	14.29%	82,140	
35	399.02	Other Tangible Property-Servers Software	69,173	-	69,173	14.29%	9,885	
36	399.03	Other Tangible Property-Network-Hardware	327,663	-	327,663	11.11%	36,403	
37	399.06	Other Tangible Property-PC Hardware	7,297,931	-	7,297,931	14.29%	1,042,874	
38	399.07	Other Tangible Property-PC Software	1,050,503	-	1,050,503	14.29%	150,117	
39	399.08	Other Tangible Property-Application Software	2,140,643	-	2,140,643	14.29%	305,898	
40		Subtotal (Sum of Ln 20 through Ln 39)	$ 99,708,919	$ 10,740,398	$ 88,968,521	4.72%	$ 4,200,202	
41								
42		Accrual for Reserve Deficiency (2)					$ 70,367	
43								
44		Total Mid-Tex Direct (Ln 17 plus Ln 40 plus Ln 42)					$ 84,381,499	

ATMOS ENERGY CORP., MID-TEX DIVISION
DEPRECIATION AND AMORTIZATION EXPENSE
BASED ON PLANT IN SERVICE AS OF SEPTEMBER 30, 2011

Line No.	Acct. (a)	Description (b)	Total Plant (c)	Non-depreciable and Fully Depreciated Plant (d)	Depreciable Plant (e)=(c)-(d)	Rate (f)	Proposed Depreciation Expense Total (g)=(e)x(f)-(h)	Depreciation Expense Cleared to Capital (h)=(e)*(f)*cap rate
45								
46								
47	SSU - Customer Support (Div 012):							
48	General Plant							
49	389	Land & Land Rights (1)	$ 2,874,240	$ 2,874,240	$ -	0.00%	$ -	
50	390	Structures & Improvements	13,180,105	-	13,180,105	3.34%	440,216	
51	390.09	Improvements to Leased Premises	4,405,863	-	4,405,863	4.06%	178,878	
52	391	Office Furniture & Equipment	1,124,491	-	1,124,491	4.03%	45,317	
53	391.02	Remittance Processing Equipment	-	-	-	4.03%	-	
54	391.03	Office Furniture & Equipment	-	-	-	4.03%	-	
55	392	Transportation Equipment	-	-	-	28.96%	-	
56	393	Stores Equipment	-	-	-	10.00%	-	
57	394	Tools & Work Equipment	-	-	-	8.88%	-	
58	397	Communication Equipment - Telephone	14,207,925	-	14,207,925	5.54%	787,119	
59	398	Miscellaneous Equipment	2,980	-	2,980	1.72%	51	
60	399	Other Tangible Property	-	-	-	13.84%	-	
61	399.01	Other Tangible Property-Servers Hardware	6,143,377	-	6,143,377	8.62%	529,559	
62	399.02	Other Tangible Property-Servers Software	2,432,216	-	2,432,216	8.78%	213,549	
63	399.03	Other Tangible Property-Network-Hardware	518,162	-	518,162	8.72%	45,184	
64	399.04	Other Tangible Property-CPU	-	-	-	26.26%	-	
65	399.05	Other Tangible Property-MF Hardware	-	-	-	15.76%	-	
66	399.06	Other Tangible Property-PC Hardware	1,100,278	-	1,100,278	8.78%	96,604	
67	399.07	Other Tangible Property-PC Software	3,414,136	-	3,414,136	6.64%	226,699	
68	399.08	Other Tangible Property-Application Software	93,652,240	-	93,652,240	6.57%	6,152,952	
69	399.09	Other Tangible Property-System Software	-	-	-	6.21%	-	
70	399.24	Other Tangible Property-GenStartupCost	23,172,326	23,172,326	-	15.89%	-	
71		Total (Sum of Ln 49 through Ln 70)	$ 166,228,339	$ 26,046,566	$ 140,181,773		$ 8,716,127	
72		Allocation to Mid-Tex					50.79%	
73		Customer Support Allocated to Mid-Tex (Ln 71 times Ln 72)					$ 4,426,921	
74	SSU - Customer Support (Div 012):							
75	General Plant							
76	Charles K. Vaughn Center							
77	389	Land & Land Rights (1)	$ 1,887,123	$ 1,887,123	$ -	0.00%	$ -	
78	390.10	Structures & Improvements	10,400,518	-	10,400,518	3.34%	347,377	
79	397.10	Communication Equipment	271,621	-	271,621	5.54%	15,048	
80	399.10	Other Tangible Equipment	90,341	-	90,341	13.84%	12,503	
81	399.16	PC Hardware	194,015	-	194,015	8.78%	17,035	
82	399.17	PC Software	90,541	-	90,541	6.64%	6,012	
83		Total (Sum of Ln 77 through Ln 82)	$ 12,934,159	$ 1,887,123	$ 11,047,036		$ 397,975	
84		Allocation to Mid-Tex					76.47%	
85		Customer Support: Charles K. Vaughn Center Allocated to Mid-Tex (Ln 83 times Ln 84)					$ 304,314	
86		Total Customer Support Depreciation Expense Allocated to Mid-Tex (Ln 73 plus Ln 85)					$ 4,731,235	

ATMOS ENERGY CORP., MID-TEX DIVISION
DEPRECIATION AND AMORTIZATION EXPENSE
BASED ON PLANT IN SERVICE AS OF SEPTEMBER 30, 2011

Line No.	Acct.	Description	Total Plant	Non-depreciable and Fully Depreciated Plant	Depreciable Plant	Rate	Proposed Depreciation Expense Total	Depreciation Expense Cleared to Capital
	(a)	(b)	(c)	(d)	(e)=(c)-(d)	(f)	(g)=(e)x(f)-(h)	(h)=(e)*(f)*cap rate
87								
88								
89	SSU - General Office (Div 002):							
90	General Plant							
91	390	Improvements to Leased Premises	$ 8,100,692	$ 8,100,692	$ -	4.06%	$ -	
92	391	Office Furniture & Equipment	10,389,375	-	10,389,375	4.03%	418,692	
93	391.02	Remittance Processing Equipment	-	-	-	4.03%	-	
94	391.03	Office Furniture & Equipment	-	-	-	4.03%	-	
95	392	Transportation Equipment	99,143		99,143	28.96%	28,712	
96	393	Stores Equipment	-	-	-	10.00%	-	
97	394	Tools & Work Equipment	185,402	-	185,402	8.88%	16,464	
98	395	Laboratory Equipment	12,100		12,100	10.00%	1,210	
99	397	Communication Equipment - Telephone	2,193,131	-	2,193,131	5.54%	121,499	
100	398	Miscellaneous Equipment	380,416	-	380,416	1.72%	6,543	
101	399	Other Tangible Property	162,268	-	162,268	13.84%	22,458	
102	399.01	Other Tangible Property-Servers Hardware	23,670,982	-	23,670,982	8.62%	2,040,439	
103	399.02	Other Tangible Property-Servers Software	14,090,396	-	14,090,396	8.78%	1,237,137	
104	399.03	Other Tangible Property-Network-Hardware	3,871,538	-	3,871,538	8.72%	337,598	
105	399.04	Other Tangible Property-CPU	-	-	-	26.26%	-	
106	399.05	Other Tangible Property-MF Hardware	-	-	-	15.76%	-	
107	399.06	Other Tangible Property-PC Hardware	2,557,781	-	2,557,781	8.78%	224,573	
108	399.07	Other Tangible Property-PC Software	1,854,955	-	1,854,955	6.64%	123,169	
109	399.08	Other Tangible Property-Application Software	84,861,784	-	84,861,784	6.57%	5,575,419	
110	399.09	Other Tangible Property-System Software	2,614,619	2,614,619	-	6.21%	-	
111	399.24	Other Tangible Property-GenStartupCost	-	-	-	15.89%	-	
112		Total (Sum of Ln 91 through Ln 111)	$ 155,044,583	$ 10,715,311	$ 144,329,272		$ 10,153,913	
113		Allocation to Mid-Tex					37.60%	
114		General Office Allocated to Mid-Tex (Ln 112 times Ln 113)					$ 3,817,871	
115	SSU - General Office (Div 002):							
116	General Plant							
117	Greenville Data Center (010.11520)							
118	390.05	G-Structures & Improvements	$ 9,087,900	$ -	$ 9,087,900	3.34%	$ 303,536	
119	391.04	G-Office Furniture & Equip.	63,741	-	63,741	4.03%	2,569	
120		Total (Sum of Ln 118 through Ln 119)	$ 9,151,641	$ -	$ 9,151,641		$ 306,105	
121		Allocation to Mid-Tex					13.43%	
122		General Office: Greenville Data Center Allocated to Mid-Tex (Ln 120 times Ln 121)					$ 41,106	
123	Total SSU -General Office Depreciation Expense Allocated to Mid-Tex (Ln 114 plus Ln 122)						$ 3,858,977	
124								
125	Total SSU Depreciation Expense Allocated to Mid-Tex (Ln 86 plus Ln 123)						$ 8,590,212	
126	Total Mid-Tex Depreciation and Amortization Expense (Ln 44 plus Ln 125)						$ 92,971,711	

ATMOS ENERGY CORP., MID-TEX DIVISION
DEPRECIATION RATE SUMMARY

DS **Please see the notes at bottom of page for depreciation rate toggle!**

Line No.	Acct.	Description	Reference	Company Filed (current)	Company Proposed (1)
	(a)	(b)	(c)	(d)	(e)
1	Mid-Tex:				
2	374	Land			0.00%
3	374.02	Land Rights			0.98%
4	374	Land & Land Rights			1.15%
5	375	Structures & Improvements			1.71%
6	376.00	Mains-Cathodic Protection			1.85%
7	376.01	Mains-Steel			3.97%
8	376.02	Mains-Plastic			2.21%
9	378	M&R Station Equipment - General			3.09%
10	379	M&R Station Equipment - City Gate			1.88%
11	380	Services			3.67%
12	381	Meters			3.31%
13	382	Meter Installations			3.66%
14	383	House Regulators			3.50%
15	385	Industrial M&R Station Equipment			2.80%
16		Distribution Plant Depreciation Rate		3.48%	3.07%
17					
18		General Plant Depreciation Rates:			
19	389	Land		0.00%	0.00%
20	390	Structures & Improvements		1.44%	2.54%
21	390	Air Conditioning Equipment		1.44%	2.75%
22	391	Office Furniture & Equipment		0.98%	4.00%
23	392	Transportation Equipment		0.00%	9.04%
24	393	Stores Equipment		3.37%	4.00%
25	394	Tools, Shop, and Garage Equipment		3.29%	5.00%
26	395	Laboratory Equipment		3.34%	10.00%
27	396	Power Oper. Tool & Work Equip.		0.00%	7.24%
28	397	Radio Communication Equipment		1.66%	6.67%
29	398	Miscellaneous Equipment		1.90%	2.50%
30	399	Non-Mainframe Computer Equip.		11.79%	14.29%
31	399.01	Other Tangible Property-Servers Hardware		11.79%	14.29%
32	399.02	Other Tangible Property-Servers Software		11.79%	14.29%
33	399.03	Other Tangible Property-Network-Hardware		11.79%	11.11%
34	399.06	Other Tangible Property-PC Hardware		11.79%	14.29%
35	399.07	Other Tangible Property-PC Software		11.79%	14.29%
36	399.08	Other Tangible Property-Application Software		11.79%	14.29%

37				
38	SSU - Customer Support and General Office:			
39		General Plant Depreciation Rates:		
40	390	Structures & Improvements	9.10%	3.34%
41	390.09	Improvements to Leased Premises	9.10%	4.06%
42	390.10	CKV-Structures & Improvements	9.10%	3.34%
43	391	Office Furniture & Equipment	2.13%	4.03%
44	391.02	Remittance Processing Equipment	11.37%	4.03%
45	391.03	Office Furniture & Equipment	1.17%	4.03%
46	392	Transportation Equipment	28.96%	28.96%
47	393	Stores Equipment	10.00%	10.00%
48	394	Tools & Work Equipment	10.00%	8.88%
49	395	Laboratory Equipment	10.00%	10.00%
50	397	Communication Equipment - Telephone	8.45%	5.54%
51	397.10	CKV-Communication Equipment	8.45%	5.54%
52	398	Miscellaneous Equipment	8.15%	1.72%
53	399	Other Tangible Property	4.66%	13.84%
54	399.01	Other Tangible Property-Servers Hardware	6.95%	8.62%
55	399.02	Other Tangible Property-Servers Software	4.00%	8.78%
56	399.03	Other Tangible Property-Network-Hardware	9.30%	8.72%
57	399.04	Other Tangible Property-CPU	26.26%	26.26%
58	399.05	Other Tangible Property-MF Hardware	15.76%	15.76%
59	399.06	Other Tangible Property-PC Hardware	14.86%	8.78%
60	399.07	Other Tangible Property-PC Software	9.02%	6.64%
61	399.08	Other Tangible Property-Application Software	11.11%	6.57%
62	399.09	Other Tangible Property-System Software	6.21%	6.21%
63	399.10	CKV-Other Tangible Equipment	4.66%	13.84%
64	399.16	CKV-PC Hardware	14.86%	8.78%
65	399.17	CKV-PC Software	9.02%	6.64%
66	399.24	Other Tangible Property-GenStartupCost	15.89%	15.89%
67				
68	Notes:		**Enter here ==>**	2

69 1. Depreciation rates are as filed in GUD 10147.
70 2. Enter a "1" in the yellow box to calculate SSU depreciation expense using the depreciation
71 rates from the Company's appeal filing
72 3. Enter a "2" in the yellow box to calculate SSU depreciation expense using the depreciation
73 rates proposed in GUD 10147

ATMOS ENERGY CORP., MID-TEX DIVISION
TAXES OTHER THAN INCOME TAX - ACCOUNT 408.1
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Per Book Amount	Adjustments	Adjusted Amount
	(a)	(b)	(c)	(d)=(b)+(c)
1	Non Revenue - Related			
2	Ad Valorem Tax	$ 21,899,700	$ (770,374)	$ 21,129,326
3	Payroll Tax	2,645,661	77,131	2,722,791
4	DOT Pipeline User Fee	75,921	-	75,921
5	Non Revenue - Related Taxes Allocated from SSU	2,570,204	(421,374)	2,148,830
6	Total Non Revenue - Related (Sum Ln 2 through Ln 5)	$ 27,191,485	$ (1,114,617)	$ 26,076,868
7				
8	Revenue - Related			
9	State Gross Receipts - Tax	$ 18,952,339	$ 1,297,396	$ 20,249,735
10	Franchise Fees	56,312,686	3,854,924	60,167,610
11	Railroad Commission Fees	58,533	4,007	62,540
12	Total Revenue - Related (Sum Ln 9 through Ln 11)	$ 75,323,559	$ 5,156,327	$ 80,479,885
13				
14	Total Taxes Other Than Income (Ln 6 plus Ln 12)	$ 102,515,044	$ 4,041,709	$ 106,556,753

ATMOS ENERGY CORP., MID-TEX DIVISION
TAXES OTHER THAN INCOME TAX WORKPAPER
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description (a)		Amount (b)
1	Mid-Tex Direct:		
2	Payroll Tax		
3	Base Labor Adjustment for Mid-Tex Direct (Schedule_F-2.1)	$	1,008,245
4	Statutory Tax Rate		7.65%
5	Direct Payroll Tax Expense for Base Labor Adjustment (Ln 3 times Ln 4)	$	77,131
6			
7	Direct Payroll Tax Expense for test period	$	2,645,661
8	Total Proposed Payroll Tax (Ln 5 plus Ln 7)	$	2,722,791
9			
10	Ad Valorem Tax		
11	Mid-Tex Payment of Property Taxes (1) (2)	$	21,690,830
12	Capitalized Property Taxes		(561,504)
13	Total Mid-Tex Ad Valorem Tax (Sum of Ln 11 through Ln 12)	$	21,129,326
14			
15	Revenue-Related Taxes:		
16	Total Operating Revenues Per Book (FERC Accounts 480-495)	$	1,192,606,763
17	Determination of Tax Rates:		
18	State Gross Receipts Tax Expense (4081-30109)	$	18,952,339
19	Ratio to Total Operating Revenues (Ln 18 divided by Ln 16)		1.5892%
20			
21	Franchise Fees Expense (4081-30107)	$	56,312,686
22	Ratio to Total Operating Revenues (Ln 21 divided by Ln 16)		4.7218%
23			
24	Railroad Commission Fee Expense (4081-30112)	$	58,533
25	Ratio to Total Operating Revenues (Ln 24 divided by Ln 16)		0.0049%
26			
27	State Gross Receipts Tax		
28	Revenue Requirement (Schedule A, Page 2, Col (g), Ln 20)	$	1,274,247,490
29	Effective Tax Rate (Ln 19)		1.5892%
30	Proposed State Gross Receipts Tax at Projected Rates (Ln 28 times Ln 29)	$	20,249,735
31			
32	Franchise Fees		
33	Revenue Requirement (Schedule A, Page 2, Col (g), Ln 20)	$	1,274,247,490
34	Effective Tax Rate (Ln 22)		4.7218%
35	Proposed Franchise Fees at Projected Rates (Ln 33 times Ln 34)	$	60,167,610
36			
37	Railroad Commission Fee		
38	Revenue Requirement (Schedule A, Page 2, Col (g), Ln 20)	$	1,274,247,490
39	Effective Tax Rate (Ln 25)		0.0049%
40	Proposed Railroad Commission Fee at Projected Rates (Ln 38 times Ln 39)	$	62,540

ATMOS ENERGY CORP., MID-TEX DIVISION
TAXES OTHER THAN INCOME TAX WORKPAPER
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description		Amount
	(a)		(b)
41	SSU:		
42	Payroll Tax Allocated to Mid-Tex		
43	Adjusted Labor Expense Allocated to Mid-Tex (WP_F-5.2, Col (g), Ln 101)	$	20,277,265
44	Statutory Tax Rate		7.65%
45	Payroll Tax Expense Allocated to Mid-Tex (Ln 43 times Ln 44)	$	1,551,211
46	Add: Benefit-Related Payroll Tax Expense Allocated to Mid-Tex	$	78,211
47	Add: Payroll Tax for FUTA & SUTA Allocated to Mid-Tex	$	85,891
48	Total Proposed Payroll Tax Expense Allocated to Mid-Tex (Sum of Ln 45 through Ln 47)	$	1,715,313
49			
50	Ad Valorem Tax Allocated to Mid-Tex (1)		
51	Shared Services General Office Tax Payment	$	524,992
52	Allocation to Mid-Tex		37.60%
53	General Office Ad Valorem Tax Expense Allocated to Mid-Tex (Ln 51 times Ln 52)	$	197,397
54			
55	Shared Services Customer Support Tax Payment	$	441,257
56	Allocation to Mid-Tex		50.79%
57	Customer Support Ad Valorem Tax Expense Allocated to Mid-Tex (Ln 55 times Ln 56)	$	224,114
58			
59	Total Proposed SSU Ad Valorem Tax Expense Allocated to Mid-Tex (Ln 53 plus Ln 57)	$	421,511
60			
61	Other Tax Allocated to Mid-Tex		
62	Excise Tax (Test Year Amount)	$	31,930
63	Allocation to Mid-Tex		37.60%
64	Total Proposed SSU Excise Tax Expense Allocated to Mid-Tex (Ln 62 times Ln 63)	$	12,006
65			
66	Total Non Revenue - Related Tax Expenses Allocated to Mid-Tex (Ln 48 + Ln 59 + Ln 64)	$	2,148,830
67			
68	Note:		
70	1. Working Gas in Storage (FERC Account 164.1) was moved from Mid-Tex to		
71	Pipeline to reflect GUD 9869 Final Order classification for rate purposes.		
72	2. Ad Valorem taxes based on asset valuation as of December 31, 2010.		

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") ADJUSTED TOTAL LABOR ALLOCATED TO MID-TEX FOR PAYROLL TAX CALCULATION
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Per Book SSU O&M Labor	FY 12 Capitalization Rate (1)	Four-Factor Allocation Factor (1), (2)	Total	SSU Allocated to Capital (3)	Expense Allocated to Mid-Tex
	(a)	(b)	(c)	(d)	(e) = (b) * (d)	(f) = (e) * (c)	(g) = (e) - (f)
1	1001 SS Dallas Executive Chairman	$ 832,062	58.49%	37.60%	$ 312,855	$ 183,003	$ 129,852
2	1101 SS Dallas Chief Financial Officer	457,000	58.49%	37.60%	171,832	100,512	71,320
3	1105 SS Dallas Audit	-	0.00%	37.60%	-	-	-
4	1106 SS Dallas Treasurer	155,504	59.08%	37.60%	58,470	34,545	23,924
5	1107 SS Dallas Treasury	393,250	58.49%	37.60%	147,862	86,491	61,371
6	1108 SS Dallas Risk Management	457,893	80.00%	37.60%	172,168	137,734	34,434
7	1110 SS Dallas Procurement	89,148	49.25%	38.72%	34,518	16,999	17,519
8	1111 SS Dallas Purchasing	301,039	56.41%	38.72%	116,562	65,757	50,805
9	1112 SS Dallas Mail & Supply	21,123	15.21%	38.72%	8,179	1,244	6,935
10	1114 SS Dallas Vice Pres & Controller	223,852	24.97%	37.60%	84,169	21,016	63,152
11	1116 SS Dallas Taxation	183,914	5.70%	37.60%	69,152	3,942	65,210
12	1117 SS Dallas Acctg Services	142,163	49.68%	37.60%	53,453	26,553	26,900
13	1118 SS Dallas Supply Chain	214,819	40.26%	38.72%	83,178	33,489	49,689
14	1119 SS Dallas General Accounting	549,046	58.49%	37.60%	206,441	120,757	85,684
15	1120 SS Dallas Accounts Payable	537,939	16.54%	37.60%	202,265	33,448	168,817
16	1121 SS Dallas Plant Accounting	489,915	90.00%	37.60%	184,208	165,787	18,421
17	1123 SS Dallas Gas Accounting	272,744	0.00%	38.72%	105,606	-	105,606
18	1125 SS Dallas Financial Reporting	713,419	0.00%	37.60%	268,245	-	268,245
19	1126 SS Dallas Payroll	516,330	58.49%	37.60%	194,140	113,561	80,579
20	1128 SS Dallas Property & Sales Tax	1,043,135	6.88%	37.60%	392,219	26,965	365,254
21	1129 SS Dallas Income Tax	428,793	2.00%	37.60%	161,226	3,225	158,002
22	1130 SS Dallas Business Planning and Analysis	465,043	53.12%	37.60%	174,856	92,886	81,970
23	1132 SS Dallas Investor Relations (4)	372,354	0.00%	0.00%	-	-	-
24	1133 SS Dallas Corporate Communications	673,076	0.00%	37.60%	253,077	-	253,077
25	1134 SS Dallas IT	1,098,220	46.43%	37.60%	412,931	191,723	221,208

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") ADJUSTED TOTAL LABOR ALLOCATED TO MID-TEX FOR PAYROLL TAX CALCULATION
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Per Book SSU O&M Labor	FY 12 Capitalization Rate (1)	Four-Factor Allocation Factor (1), (2)	Total	SSU Allocated to Capital (3)	Expense Allocated to Mid-Tex
	(a)	(b)	(c)	(d)	(e) = (b) * (d)	(f) = (e) * (c)	(g) = (e) - (f)
26	1135 SS Dallas IT Application Support	1,664,097	11.50%	37.60%	625,701	71,956	553,745
27	1137 SS Dallas IT Operations	1,807,635	26.96%	37.60%	679,671	183,216	496,455
28	1139 SS Dallas IT Telecommunications	245,609	36.84%	37.60%	92,349	34,023	58,326
29	1141 SS Dallas Gas Purchase Accounting	424,553	0.00%	45.38%	192,662	-	192,662
30	1144 SS Dallas Rate Administration	731,828	0.00%	45.38%	332,103	-	332,103
31	1145 SS Dallas Revenue Accounting	310,432	0.00%	45.38%	140,874	-	140,874
32	1146 SS Dallas IT Enterprise Solutions	646,346	46.32%	37.60%	243,026	112,559	130,467
33	1150 SS Dallas Strategic Planning	344,750	53.57%	37.60%	129,626	69,442	60,183
34	1153 SS Dallas Distribution Acctg	63,692	0.00%	45.38%	28,904	-	28,904
35	1154 SS Dallas Rates & Regulatory	1,613,120	60.86%	38.72%	624,600	380,104	244,496
36	1155 SS Dallas Texas Gas Pipeline Accounting	-	0.00%	0.00%	-	-	-
37	1156 SS Dal - IT Customer Svc Support	796,106	25.00%	50.79%	404,342	101,086	303,257
38	1158 SS CCC IT Support	357,513	5.47%	50.79%	181,581	9,930	171,651
39	1159 SS Dallas Director Technical Training	85,988	0.00%	38.72%	33,295	-	33,295
40	1161 SS Dallas Benefits and Payroll Accounting	238,128	58.49%	37.60%	89,536	52,374	37,162
41	1165 SS Dallas IT Production Services & Support	439,506	14.00%	37.60%	165,254	23,136	142,119
42	1171 SS Regulatory Accounting Services	243,071	60.86%	38.72%	94,117	57,276	36,842
43	1201 SS Dallas President & CEO	752,877	58.49%	37.60%	283,082	165,587	117,494
44	1203 SS Amarillo Customer Support Center	6,179,890	15.50%	50.79%	3,138,766	486,490	2,652,276
45	1209 SS Dallas Safety & Compliance	159,146	0.00%	38.72%	61,621	-	61,621
46	1210 SS Waco Customer Support Center	8,430,578	15.50%	50.79%	4,281,891	663,668	3,618,223
47	1212 SS CSC-Customer Contact Management	-	15.50%	50.79%	-	-	-
48	1213 SS Dallas Quality Assurance	1,355,287	0.00%	50.79%	688,350	-	688,350
49	1214 SS Dallas Workforce Management	416,818	0.00%	50.79%	211,702	-	211,702
50	1215 SS Dispatch Operations	2,353,494	15.50%	50.79%	1,195,340	185,271	1,010,069
51	1225 SS Dallas Regulated Operations	139,732	73.94%	50.79%	70,970	52,478	18,492
52	1226 SS Dallas Customer Service	782,075	0.00%	50.79%	397,216	-	397,216
53	1227 SS Dallas Customer Program Management	894,578	41.07%	50.79%	454,356	186,615	267,741
54	1228 SS Dallas Customer Revenue Management	2,309,972	0.00%	50.79%	1,173,235	-	1,173,235

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") ADJUSTED TOTAL LABOR ALLOCATED TO MID-TEX FOR PAYROLL TAX CALCULATION
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Per Book SSU O&M Labor	FY 12 Capitalization Rate (1)	Four-Factor Allocation Factor (1), (2)	Total	SSU Allocated to Capital (3)	Expense Allocated to Mid-Tex
	(a)	(b)	(c)	(d)	(e) = (b) * (d)	(f) = (e) * (c)	(g) = (e) - (f)
55	1401 SS Dallas Employment & Employee Relations	629,253	0.00%	38.72%	243,647	-	243,647
56	1402 SS Dallas Executive Compensation	-	0.00%	37.60%	-	-	-
57	1403 SS Dallas Human Resources - Vice Pres	515,684	58.49%	37.60%	193,897	113,419	80,478
58	1405 SS Dallas Compensation & Benefits	760,287	0.00%	38.72%	294,383	-	294,383
59	1407 SS Dallas Facilities	450,996	36.00%	37.60%	169,575	61,047	108,528
60	1408 SS Dallas Employee Development	974,070	0.00%	37.60%	366,250	-	366,250
61	1410 SS Dallas Corporate Development	65,365	0.00%	37.60%	24,577	-	24,577
62	1414 SS Tech Training Delivery	752,600	0.00%	38.72%	291,407	-	291,407
63	1415 SS Tech Training Prog & Curriculum	170,489	0.00%	38.72%	66,013	-	66,013
64	1420 SS Dallas EAPC	-	0.00%	37.60%	-	-	-
65	1463 SS HR Benefit Variance	-	15.21%	37.60%	-	-	-
66	1501 SS Corporate Legal	1,907,448	41.87%	37.60%	717,200	300,288	416,912
67	1502 SS Corporate Secretary	122,764	0.00%	37.60%	46,159	-	46,159
68	1503 SS Corporate Governmental Affairs	309,105	0.00%	38.72%	119,686	-	119,686
69	1504 SS Corporate Central Records	76,132	58.49%	38.72%	29,478	17,243	12,235
70	1505 SS Corporate Gas Contract Administration	127,307	0.00%	38.72%	49,293	-	49,293
71	1508 SS Corporate Energy Assistance	299,811	0.00%	45.38%	136,054	-	136,054
72	1821 SS Gas Supply Executive	276,895	0.00%	38.52%	106,660	-	106,660
73	1822 SS Dallas-Regional Gas Supply	146,698	0.00%	82.89%	121,598	-	121,598
74	1823 SS Dallas Gas Contract Admin	316,789	0.00%	38.72%	122,661	-	122,661
75	1825 SS Franklin-Gas Control & Storage	223,677	0.00%	0.00%	-	-	-
76	1826 SS New Orleans Gas Supply & Service	46,560	0.00%	45.38%	21,129	-	21,129
77	1827 SS Regional Supply Planning	218,877	0.00%	0.00%	-	-	-
78	1828 SS Jackson-West Region Gas Supply & Services	86,771	0.00%	0.00%	-	-	-
79	1829 SS Franklin-East Region Gas Supply & Services	-	0.00%	0.00%	-	-	-
80	1831 SS Dallas Gas Supply	94,046	0.00%	100.00%	94,046	-	94,046
81	1832 SS Dallas-Supply Planning	-	0.00%	100.00%	-	-	-
82	1833 SS Dallas-Corporate Gas Supply Risk Mgmt	89,205	0.00%	45.38%	40,481	-	40,481
83	1835 SS Franklin Gas Control	675,531	0.00%	0.00%	-	-	-
84	1836 SS TBS-System Support	222,529	0.00%	38.52%	85,718	-	85,718
85	1837 SS TBS-Application Support	669,681	0.00%	38.52%	257,961	-	257,961
86	1838 SS TBS-Technical Support	421,726	0.00%	38.52%	162,449	-	162,449
87	1839 SS TBS-Transportation & Scheduling	194,829	0.00%	38.52%	75,048	-	75,048

ATMOS ENERGY CORP., MID-TEX DIVISION
SHARED SERVICES ("SSU") ADJUSTED TOTAL LABOR ALLOCATED TO MID-TEX FOR PAYROLL TAX CALCULATION
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Per Book SSU O&M Labor	FY 12 Capitalization Rate (1)	Four-Factor Allocation Factor (1), (2)	Total	SSU Allocated to Capital (3)	Expense Allocated to Mid-Tex
	(a)	(b)	(c)	(d)	(e) = (b) * (d)	(f) = (e) * (c)	(g) = (e) - (f)
88	1901 SS Dallas Employee Relocation Exp (5)	188,262	0.00%	37.60%	70,787	-	70,787
89	1901 SS Dallas Employee Relocation Exp (5)	82,001	0.00%	50.79%	41,648	-	41,648
90	1903 SS Dallas Controller - Miscellaneous	-	0.00%	37.60%	-	-	-
91	1904 SS Dallas Performance Plan (4)	-	36.30%	0.00%	-	-	-
92	1905 SS Outside Director Retirement Cost	-	0.00%	37.60%	-	-	-
93	1908 SS Dallas SEBP (4)	-	0.00%	0.00%	-	-	-
94	1910 SS Dallas Overhead Capitalized (3)	-	0.00%	40.54%	-	-	-
95	1913 SS Dallas Fleet Management	310,589	49.35%	38.72%	120,260	59,349	60,911
96	1915 SS Dallas Insurance	-	0.00%	37.60%	-	-	-
97	TOTAL (Sum Ln 1 through Ln 96)	$ 55,844,579			$ 23,949,847	$ 4,846,195	$ 19,103,652
98							
99	Add: SSU Labor Adjustment (WP_F-2.1, Col (d), Ln 18)						$ 1,173,613
100							
101	Total Adjusted SSU Labor Allocated to Mid-Tex Account 922 (Ln 97 plus Ln 99)						$ 20,277,265
102					11,611,825	1,574,522	10,037,303
103	Notes:				12,338,022	3,271,674	9,066,349
104	1. Factors are displayed only if applicable to Mid-Tex.						
105	2. Based on FY12 factors, adjusted to the four-factor formula including Operating Income.					86.44%	
106	The four-factor formula calculation does not include the states of Iowa, Illinois and Missouri.					73.48%	
107	3. The Total represents the amount that would be credited from Cost Center 1910.						
108	4. Allocation percentages have been set to zero to align with GUD 9869 for cost centers 1132, 1904 and 1908. Cost center 1350 is no longer active.						
109	All costs in cost center 1507 are below the line.						
110	5. Cost center 1901 expenses have been divided between General Office (Div 002) and Customer Support (Div 012) and separately allocated.						

ATMOS ENERGY CORP., MID-TEX DIVISION
TOTAL INCOME TAXES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description		Amount
	(a)		(b)
1	Federal Income Tax (Page 2, Col (b), Ln 12)	$	44,216,610
2	State Income Tax (Page 3, Col (c), Ln 8)		4,386,040
3			
4	Total Income Tax (Sum Ln 1 through Ln 2)	$	48,602,650

ATMOS ENERGY CORP., MID-TEX DIVISION
FEDERAL INCOME TAX
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description		Amount
	(a)		(b)
1	Return on Rate Base (Schedule G, Col (c), Ln 6)	$	129,638,514
2			
3	Interest Expense:		
4	Rate Base (Schedule B, Col (e), Ln 21)	$	1,512,985,746
5	Weighted Cost of Debt (1)		3.14%
6	Total (Ln 4 times Ln 5)	$	47,521,952
7			
8	Taxable component of return (Ln 1 minus Ln 6)	$	82,116,562
9			
10	Tax factor (1 / .65) * (.35)		53.85%
11			
12	Federal Income Taxes (Ln 8 times Ln 10)	$	44,216,610
13			
14	Note:		
15	1. Source Schedule G, Col (b) Ln 17.		

ATMOS ENERGY CORP., MID-TEX DIVISION
STATE FRANCHISE ("GROSS MARGIN") TAX

TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Reference		Amount
	(a)	(b)		(c)
1	Total Proposed Operating Revenues	Schedule A, Col (g), Ln 20	$	1,274,247,490
2	Less:			
3	Total Purchased Gas Costs (Rider GCR)	Schedule A, Col (g), Ln 4		746,311,816
4	Taxes Other Than Federal Income Tax- Revenue Related	Schedule F-5, Col (d), Ln 12		80,479,885
5	Bad Debt Expense, not included in Purchased Gas Costs	Schedule F-1, Col (e), Ln 27		3,589,132
6	Gross Profit (Ln 1 minus Sum of Ln 3 through Ln 5)		$	443,866,657
7	Tax Rate			1%
8	Tax Due (Ln 6 times Ln 7)		$	4,438,667
9				
10	Business Loss Carryforward			52,627
11				
12	Total Tax Due (Ln 8 minus Ln 10)		$	4,386,040

ATMOS ENERGY CORP., MID-TEX DIVISION
INTEREST EXPENSE - CUSTOMER DEPOSITS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description		Amount
	(a)		(b)
1	Adjusted Customer Deposits	$	21,808,614
2			
3	Current Interest Rate (1)		0.12%
4			
5	Interest on Customer Deposits (Ln 1 times Ln 3)	$	26,170
6			
7	Note:		
8	1. Interest Rate per the Public Utility Commission of Texas Press Release		
9	dated December 1, 2011.		

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY OF RETURN
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Proposed Rates (1)		Proposed Amounts
	(a)	(b)		(c)
1	Net Operating Income/Return			
2				
3	Cost of Debt	6.50%	$	47,521,952
4	Cost of Equity	10.50%		82,116,562
5				
6	Total Return on Invested Capital		$	129,638,514
7				
8	Rate Base - Capitalization Structure			
9				
10	Debt	48.31%	$	730,923,252
11	Equity	51.69%		782,062,494
12				
13	Total Invested Capital		$	1,512,985,746
14				
15	Percent Return - After Tax			
16				
17	Cost of Debt	3.14%		
18	Return on Equity	5.43%		
19				
20	Percent Return - After Tax	8.57%		
21				
22	Note:			
23	1. Capital Structure and Cost of Debt are March 31, 2012 actual			
24	book balances.			

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF RIDER GCR PART A
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Month/Year	Estimated Gas Cost Factor (EGCF)/Ccf (1)	
	(a)	(b)	
1	October 31, 2010	$0.5250	
2	November 30, 2010	$0.5250	
3	December 31, 2010	$0.5250	
4	January 31, 2011	$0.4500	
5	February 28, 2011	$0.4250	
6	March 31, 2011	$0.3800	
7	April 30, 2011	$0.4200	
8	May 31, 2011	$0.4400	
9	June 30, 2011	$0.4500	
10	July 31, 2011	$0.3500	
11	August 31, 2011	$0.5000	
12	September 30, 2011	$0.5000	
13			
14	Average	$0.4575	
15			
16			Rider GCR
17		Usage (Ccf)	Part A
18	Rate R	766,043,261	$ 350,465,430
19	Rate C	502,902,414	230,078,273
20	Rate I	16,495,898	7,546,887
21	Total (Sum Ln 18 to Ln 20)	1,285,441,573	$ 588,090,591
22			
23	Note:		
24	1. The filed GCR rates are per Mcf. The rates shown in Column (b)		
25	have been converted to a per Ccf rate (i.e. filed rate/10).		

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF RIDER GCR PART B
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Item	Estimated Billing Units	CGS - Mid-Tex Rate (1)	Total	Quantity	Rate Per Unit
	(a)	(b)	(c)	(d)	(e)	(f)
1	Capacity Charge (2)	29,398,248	$5.1911	$ 152,609,245		
2						
3	Usage Charge					
4	Residential (MMBtu)	[redacted]				
5	Commercial (MMBtu)	[redacted]				
6	Industrial & Transportation (MMBtu)	40,453,255				
7	Sub-Total Mid-Tex Sales (Sum Ln 4 through Ln 6)	170,393,292				
8	Lost and Unaccounted for Gas (3) (Ln 7 times 2.5932%)	4,418,639				
9	Total Deliveries from APT to Mid-Tex (Sum Ln 7 through Ln 8)	174,811,931	$0.0276	$ 4,824,809		
10						
11	Estimated Pipeline Cost (Ln 1 plus Ln 9)			$ 157,434,054		
12	Gas Utility Tax at 0.5%			787,170		
13						
14	Total Rider GCR Part B (Ln 11 plus Ln 12)			$ 158,221,225		
15						
16	Present Allocation:					
17		Allocation Factor	Rider GCR Part B	Volumes		Rate Per Unit
18	Rate R	0.64302686	$ 101,740,497	766,043,261	Ccf	$0.1328
19	Rate C	0.30547645	48,332,858	502,902,414	Ccf	$0.0961
20	Industrial & Transportation	0.05149670	8,147,870	40,453,255	MMBtu	$0.2014
21	Total Rider GCR Part B (Sum Ln 18 through Ln 20)		$ 158,221,225			
22						
23	Notes:					
24	1. Capacity Charge and Usage Charge are per GUD No. 10144.					
25	2. MDQ is per contract between Mid-Tex and Atmos Pipeline - Texas.					
26	3. Includes Lost and Unaccounted for Gas factor of 2.5932% per GUD No. 9400, Finding of Fact No. 120A.					

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY OF CURRENT AND PROPOSED RATE STRUCTURE - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Current Unincorporated	Proposed Unincorporated
	(a)	(b)	(c)
1	**Rate R**		
2	Customer Charge per month	$18.87	$17.70
3			
4	Consumption Charge per CCF	$0.04315	$0.04172
5			
6			
7	**Rate C**		
8	Customer Charge per month	$38.04	$34.72
9			
10	Consumption Charge per CCF	$0.05748	$0.06589
11			
12			
13	**Rate I & T**		
14	Customer Charge per month	$678.33	$600.00
15			
16	Consumption Charge per MMBTU:		
17	First 1,500 MMBTU	$0.1373	$0.2473
18	Next 3,500 MMBTU	$0.0999	$0.1812
19	Over 5,000 MMBTU	$0.0159	$0.0389

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY OF CURRENT AND PROPOSED RATE STRUCTURE - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	Current ICL	Proposed ICL
	(a)	(b)	(c)
1	**Rate R**		
2	Customer Charge per month	$7.50	$ 17.70
3			
4	Consumption Charge per CCF	$0.25116	$0.04172
5			
6			
7	**Rate C**		
8	Customer Charge per month	$16.75	$ 34.72
9			
10	Consumption Charge per CCF	$0.10217	$0.06589
11			
12			
13	**Rate I & T**		
14	Customer Charge per month	$450.00	$ 600.00
15			
16	Consumption Charge per MMBTU:		
17	First 1,500 MMBTU	$0.2750	$0.2473
18	Next 3,500 MMBTU	$0.2015	$0.1812
19	Over 5,000 MMBTU	$0.0433	$0.0389

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY PROOF OF REVENUE AT CURRENT RATES - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line	Description		Total	Reference
	(a)		(b)	(c)
	Rate R			
1	Rate Characteristics:			
2	Customer Charge		$18.87	GUD 10162
3				
4				
5	Consumption Charge ($/Ccf)		$0.04315	GUD 10162
6				
7	Rider GCR Part A		$0.45750	Schedule H
8	Rider GCR Part B		$0.13281	Schedule I
9				
10	Billing Units (1):			
11	Bills		17,314,932	Billing Determinants Study
12	Total Ccf		[redacted]	Billing Determinants Study
13				
14	Present Revenue:			
15	Customer Charge	$	326,732,767	Ln 2 times Ln 11
16				
17	Consumption Charge		33,054,767	Ln 5 times Ln 12
18	Base Revenue	$	359,787,534	Ln 15 plus Ln 17
19	Rider GCR Part A		350,465,430	Ln 7 times Ln 12
20	Rider GCR Part B		101,740,497	Ln 8 times Ln 12
21	Subtotal	$	811,993,460	Sum Ln 18 through Ln 20
22	Revenue Related Taxes		54,741,928	Ln 21 times WP_5.1 excel cell G36
23				
24	Total Present Revenue- Rate R	$	866,735,389	Ln 21 plus Ln 22
25				
26	Note 1: See Billing Determinants Study for details.			

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY PROOF OF REVENUE AT CURRENT RATES - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line	Description		Total	Reference
	(a)		(b)	(c)
	Rate C			
1	Rate Characteristics:			
2	Customer Charge		$38.04	GUD 10162
3				
4				
5	Consumption Charge ($/Ccf)		$0.05748	GUD 10162
6				
7	Rider GCR Part A		$0.45750	Schedule H
8	Rider GCR Part B		$0.09611	Schedule I
9				
10	Billing Units (1):			
11	Bills		1,471,479	Billing Determinants Study
12	Total CCF		[redacted]	Billing Determinants Study
13				
14	Present Revenue:			
15	Customer Charge	$	55,975,061	Ln 2 times Ln 11
16				
17	Consumption Charge		28,906,831	Ln 5 times Ln 12
18	Base Revenue	$	84,881,892	Ln 15 plus Ln 17
19	Rider GCR Part A		230,078,273	Ln 7 times Ln 12
20	Rider GCR Part B		48,332,858	Ln 8 times Ln 12
21	Subtotal	$	363,293,023	Sum Ln 18 through Ln 20
22	Revenue Related Taxes		24,492,021	Ln 21 times WP_5.1 excel cell G36
23				
24	Total Present Revenue- Rate C	$	387,785,044	Ln 21 plus Ln 22
25				
26	Note 1: See Billing Determinants Study for details.			

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY PROOF OF REVENUE AT CURRENT RATES - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line	Description	Total	Reference
	(a)	(b)	(c)
	Rate I &T		
1	Rate Characteristics:		
2	Customer Charge	$678.33	GUD 10162
3			
4			
5	Block 1 ($/MMBTU)	$0.1373	GUD 10162
6	Block 2 ($/MMBTU)	$0.0999	GUD 10162
7	Block 3 ($/MMBTU)	$0.0159	GUD 10162
8			
9	Rider GCR Part A	$4.57501	Schedule H
10	Rider GCR Part B	$0.20141	Schedule I
11			
12	Consumption Characteristics:		
13	Block 1	0.23924	(1)
14	Block 2	0.29036	(1)
15	Block 3	0.47040	(1)
16			
17	Billing Units (1):		
18	Bills	10,380	Billing Determinants Study
19	Block 1	9,678,031	Billing Determinants Study
20	Block 2	11,745,997	Billing Determinants Study
21	Block 3	19,029,227	Billing Determinants Study
22	Total MMBTU	40,453,255	
23			
24	Sales Volumes	1,689,180	Billing Determinants Study
25			

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY PROOF OF REVENUE AT CURRENT RATES - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line	Description		Total	Reference
	(a)		(b)	(c)
26	Present Revenue:			
27	Customer Charge	$	7,041,065	Ln 2 time Ln 18
28				
29	Block 1		1,328,794	Ln 5 times Ln 19
30	Block 2		1,173,425	Ln 6 times Ln 20
31	Block 3		302,565	Ln 7 times Ln 21
32	Base Revenue	$	9,845,849	Sum Ln 27 through Ln 31
33	Rider GCR Part A		7,546,887	Ln 9 times Ln 24
34	Rider GCR Part B		8,147,870	Ln 10 times Ln 22
35	Subtotal	$	25,540,606	Sum Ln 32 through Ln 34
36	Revenue Related Taxes		1,721,864	Ln 35 times WP_5.1 excel cell G36
37				
38	Total Present Revenue- Rate I&T	$	27,262,470	Ln 35 plus Ln 36
39				
40	Note 1: See Billing Determinants Study for details.			

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF CURRENT REVENUES BY AREA - RATE R - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Customer Charges	Customer Charge Revenue	Per Book Volume	Adjusted Volume	Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Current Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	AFFECTED CITIES	14,339,989	$ 270,595,601	621,660,902	[redacted]	$ 26,631,418	$ 297,227,020	$ 282,361,440	$ 81,969,834	$ 661,558,294	$ 44,600,084	$ 706,158,378
2	UNINCORPORATED	536,843	10,130,219	20,407,073	[redacted]	875,736	11,005,954	9,285,051	2,695,460	22,986,465	1,549,672	24,536,137
3	DALLAS ICL	2,438,100	46,006,947	130,509,900	[redacted]	5,547,612	51,554,559	58,818,939	17,075,202	127,448,701	8,592,172	136,040,873
4												
5	TOTAL	17,314,932	$ 326,732,767	772,577,876	[redacted]	$ 33,054,767	$ 359,787,534	$ 350,465,430	$ 101,740,497	$ 811,993,460	$ 54,741,928	$ 866,735,389
6												
7												
8												
9	Ratios:											
10	AFFECTED CITIES				80.57%							
11	UNINCORPORATED				2.65%							
12	DALLAS ICL				16.78%							
					100.00%							
				80.47%	80.5675584717789%							
				2.64%	2.6493485076667%							
				16.89%	16.7830930205543%							
				100.00%	100.00%							
13	TOTAL											

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF CURRENT REVENUES BY AREA - RATE C - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Customer Charges	Customer Charge Revenue	Per Book Volume	Adjusted Volume	Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Current Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	AFFECTED CITIES	1,205,206	$ 45,846,031	379,651,812	[redacted]	$ 21,950,763	$ 67,796,794	$ 174,712,808	$ 36,702,159	$ 279,211,761	$ 18,823,539	$ 298,035,299
2	UNINCORPORATED	25,229	959,716	7,367,385	[redacted]	427,363	1,387,079	3,401,514	714,561	5,503,154	371,005	5,874,158
3	DALLAS ICL	241,044	9,169,314	115,303,938	[redacted]	6,528,705	15,698,019	51,963,952	10,916,138	78,578,109	5,297,478	83,875,587
4												
5	TOTAL	1,471,479	$ 55,975,061	502,323,136	[redacted]	$ 28,906,831	$ 84,881,892	$ 230,078,273	$ 48,332,858	$ 363,293,023	$ 24,492,021	$ 387,785,044
6												
7												
8												
9	Ratios:											
10	AFFECTED CITIES				75.94%							
11	UNINCORPORATED				1.48%							
12	DALLAS ICL				22.59%							
13	TOTAL				100.00%							
				75.58%	75.936247873496%							
				1.47%	1.478415856521%							
				22.95%	22.585336269983%							
				100.00%	100.00%							

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF CURRENT REVENUES BY AREA - RATE I&T - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Meter Charges	Customer Charge Revenue	Sales Volume	Transportation Volume	Total Volume	Volume Block 1	Volume Block 2	Volume Block 3	Consumption Revenue Block 1	Consumption Revenue Block 2	Consumption Revenue Block 3	Total Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Current Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
1	AFFECTED CITIES	8,460	$ 5,738,672	1,329,031	28,569,092	29,898,123	7,892,879	8,864,076	13,141,168	$ 1,083,692	$ 885,521	$ 208,945	$ 2,178,158	$ 7,916,830	$ 5,937,820	$ 6,021,914	$ 19,876,564	$ 1,340,013	$ 21,216,577
2	UNINCORPORATED	420	284,899	120,004	2,006,272	2,126,276	366,981	488,772	1,270,523	50,386	48,828	20,201	119,416	404,315	536,152	428,263	1,368,729	92,275	1,461,004
3	DALLAS ICL	1,500	1,017,495	240,145	8,188,711	8,428,856	1,418,171	2,393,149	4,617,536	194,715	239,076	73,419	507,209	1,524,704	1,072,915	1,697,693	4,295,313	289,576	4,584,889
4																			
5	TOTAL	10,380	$ 7,041,065	1,689,180	38,764,075	40,453,255	9,678,031	11,745,997	19,029,227	$ 1,328,784	$ 1,173,425	$ 302,565	$ 2,804,783	$ 9,845,849	$ 7,546,887	$ 8,147,870	$ 25,540,606	$ 1,721,864	$ 27,262,470

ATMOS ENERGY CORP., MID-TEX DIVISION
OTHER REVENUES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	FERC Account		Test Year		Adjustments		Adjusted Amounts
	(a)		(b)		(c)		(d)
1	488 (1)	$	11,772,061	$	-	$	11,772,061
2	489		987,736		555,451		1,543,187
	ATM Treasury Lock Amort				-		-
3	493		-		-		-
4	495		(52,432)		47,550		(4,882)
5	ATM BFI Dividend			$	-	$	-
6	Totals	$	12,707,364	$	603,001	$	13,310,366
7							

8 Notes:
9 1. Mid-Tex is not proposing to change any of the
10 miscellaneous service charges previously approved on Rate M.

ATMOS ENERGY CORP., MID-TEX DIVISION
NON-STANDARD CONTRACT MARGINS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No	Area	Customer	Customer Numbers	Usage MMBtu	Annual Margin Revenue
	(a)	(b)	(c)	(d)	(e)
1	SAN ANGELO	Customer 1	1270	72,003	$ 54,189
2	WICHITA FALLS	Customer 2	1521	321,028	225,668
3	GATESVILLE	Customer 3	1246	37,056	15,992
4	KILLEEN	Customer 4	1246	769,784	94,143
5	KILLEEN	Customer 5	1246	197,161	31,063
6	WAXAHACHIE	Customer 6	1319	80,090	22,923
7	ABILENE	Customer 7	1567	124,723	34,547
8	ALLEN	Customer 8	1567	75,828	20,855
9	BONHAM	Customer 9	1567	29,757	13,733
10	BROWNWOOD	Customer 10	1567	11,265	6,122
11	BRYAN	Customer 11	1567	15,609	6,851
12	BURNET	Customer 12	1567	8,931	5,674
13	CARLSBAD	Customer 13	1567	12,947	6,447
14	COLORADO CITY	Customer 14	1567	40,846	11,334
15	DENTON	Customer 15	1567	124,351	32,009
16	FORT WORTH	Customer 16	1567	385,405	86,739
17	GAINESVILLE	Customer 17	1567	9,982	5,925
18	GARLAND	Customer 18	1567	3,374	3,006
19	GATESVILLE	Customer 19	1567	209,631	53,435
20	HUTCHINS	Customer 20	1567	38,181	10,882
21	KERRVILLE	Customer 21	1567	19,606	11,667
22	MARLIN	Customer 22	1567	37,296	10,695
23	MART	Customer 23	1567	11,702	6,217
24	MEXIA	Customer 24	1567	34,271	14,297
25	SAN ANGELO	Customer 25	1567	37,242	14,900
26	SNYDER	Customer 26	1567	34,913	10,287
27	TERRELL	Customer 27	1567	34,526	10,183
28	VERNON	Customer 28	1567	16,883	7,208
29	WACO	Customer 29	1567	47,315	12,606
30	WICHITA FALLS	Customer 30	1567	107,501	27,318
31	FORT WORTH	Customer 32	1996	76,664	153,647
32	ENNIS	Customer 33	3334	153,734	31,055
33	ENNIS	Customer 34	1222	364,666	31,259
34	STEPHENVILLE	Customer 35	6720	42,155	23,743
35	ARLINGTON	Customer 36	3507	307,267	67,956
36	RICHARDSON	Customer 37	3507	199,058	31,581
37	FORT WORTH	Customer 38	1069	564,326	69,124
38	WICHITA FALLS	Customer 39	1445	2,795,314	232,642
39	WAXAHACHIE	Customer 40	1362	47,613	8,553
40	FORT WORTH	Customer 41	1398	703,747	18,468
41	DENTON	Customer 42	10430	335,467	6,062
42	FAIRVIEW	Customer 43	1742	28,441	1,138
43	JUSTIN	Customer 44	1742	749	30
44	LINCOLN PARK	Customer 45	1742	413	17
45	MCKINNEY	Customer 46	1742	870	35
46	MCKINNEY	Customer 47	1742	12,205	488
47	PONDER	Customer 48	1742	54	2
48	WYLIE	Customer 49	1742	11,807	472
49					
50	Total Non-Standard Contract Margins			7,500,004	$ 1,543,187

ATMOS ENERGY CORP., MID-TEX DIVISION
TYPICAL BILL COMPARISON - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line								July 5, 2012	
1	**Rate R @ 60 Ccf**						CURRENT	PROPOSED	CHANGE
2	Customer charge						$18.87		
3	Consumption charge	60	CCF	X	$0.04315	=	2.59		
4	Rider GCR Part A	60	CCF	X	$0.45750	=	27.45		
5	Rider GCR Part B	60	CCF	X	$0.13281	=	7.97		
6	Subtotal						$56.88		
7	Rider FF & Rider TAX		$56.88	X	0.01620	=	0.92		
8	Total						$57.80		
9									
10	Customer charge							$17.70	
11	Consumption charge	60	CCF	X	$0.04172	=		2.50	
12	Rider GCR Part A	60	CCF	X	$0.45750	=		27.45	
13	Rider GCR Part B	60	CCF	X	$0.13281	=		7.97	
14	Subtotal							$55.62	
15	Revenue-related Tax Reimbursement		$55.62	X	0.01620	=		0.90	
16	Total							$56.52	($1.28)
17									-2.21%
18									
19	**Rate C @ 300 Ccf**						CURRENT	PROPOSED	CHANGE
20	Customer charge						$38.04		
21	Consumption charge	300	CCF	X	$0.05748	=	17.24		
22	Rider GCR Part A	300	CCF	X	$0.45750	=	137.25		
23	Rider GCR Part B	300	CCF	X	$0.09611	=	28.83		
24	Subtotal						$221.36		
25	Revenue-related Tax Reimbursement		$221.36	X	0.01620	=	3.59		
26	Total						$224.95		
27									
28	Customer charge							$34.72	
29	Consumption charge	300	CCF	X	$0.06589	=		19.77	
30	Rider GCR Part A	300	CCF	X	$0.45750	=		137.25	
31	Rider GCR Part B	300	CCF	X	$0.09611	=		28.83	
32	Subtotal							$220.57	
33	Revenue-related Tax Reimbursement		$220.57	X	0.01620	=		3.57	
34	Total							$224.14	($0.81)
35									-0.36%
36	**Rate I @ 300 MMBTU**						CURRENT	PROPOSED	CHANGE
37	Customer charge						$678.33		
38	Consumption charge	300	MMBTU	X	$0.1373	=	41.19		
39	Consumption charge	0	MMBTU	X	$0.0999	=	0.00		
40	Consumption charge	0	MMBTU	X	$0.0159	=	0.00		

ATMOS ENERGY CORP., MID-TEX DIVISION
TYPICAL BILL COMPARISON - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line	Description	Quantity	Unit		Rate		CURRENT	PROPOSED	CHANGE
41	Rider GCR Part A	300	MMBTU	X	$0.4685	=	140.54		
42	Rider GCR Part B	300	MMBTU	X	$0.2014	=	60.42		
43	Subtotal						$920.48		
44	Revenue-related Tax Reimbursement	$920.48		X	0.01620	=	14.91		
45	Total						$935.39		
46									
47	Customer charge							$600.00	
48	Consumption charge	300	MMBTU	X	$0.2473	=		74.19	
49	Consumption charge	0	MMBTU	X	$0.1812	=		0.00	
50	Consumption charge	0	MMBTU	X	$0.0389	=		0.00	
51	Rider GCR Part A	300	MMBTU	X	$0.4685	=		140.54	
52	Rider GCR Part B	300	MMBTU	X	$0.2014	=		60.42	
53	Subtotal							$875.15	
54	Revenue-related Tax Reimbursement	$875.15		X	0.01620	=		14.18	
55	Total							$889.33	($46.06)
56									-4.92%
57	**Rate T @ 300 MMBTU**						**CURRENT**	**PROPOSED**	**CHANGE**
58	Customer charge						$678.33		
59	Consumption charge	300	MMBTU	X	$0.1373	=	41.19		
60	Consumption charge	0	MMBTU	X	$0.0999	=	0.00		
61	Consumption charge	0	MMBTU	X	$0.0159	=	0.00		
62	Rider GCR Part B	300	MMBTU	X	$0.2014	=	60.42		
63	Subtotal						$779.94		
64	Revenue-related Tax Reimbursement	$779.94		X	0.01620	=	12.63		
65	Total						$792.57		
66									
67	Customer charge							$ 600.00	
68	Consumption charge	300	MMBTU	X	$0.2473	=		74.19	
69	Consumption charge	0	MMBTU	X	$0.1812	=		0.00	
70	Consumption charge	0	MMBTU	X	$0.0389	=		0.00	
71	Rider GCR Part B	300	MMBTU	X	$0.2014	=		60.42	
72	Subtotal							$734.61	
73	Revenue-related Tax Reimbursement	$734.61		X	0.01620	=		11.90	
74	Total							$746.51	($46.06)
75									-5.81%

ATMOS ENERGY CORP., MID-TEX DIVISION
AVERAGE BILL COMPARISON - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line							CURRENT	July 5, 2012 PROPOSED	CHANGE
1	Rate R @ 44.2 Ccf								
2	Customer charge						$ 18.87		
3	Consumption charge	44	CCF	X	$0.04315	=	1.91		
4	Rider GCR Part A	44	CCF	X	$0.45750	=	20.22		
5	Rider GCR Part B	44	CCF	X	$0.13281	=	5.87		
6	Subtotal						$46.87		
7	Rider FF & Rider TAX	$46.87		X	0.01620	=	0.76		
8	Total						$47.63		
9									
10	Customer charge							$ 17.70	
11	Consumption charge	44	CCF	X	$0.04172	=		1.84	
12	Rider GCR Part A	44	CCF	X	$0.45750	=		20.22	
13	Rider GCR Part B	44	CCF	X	$0.13281	=		5.87	
14	Subtotal							$45.63	
15	Revenue-related Tax Reimbursement	$45.63		X	0.01620	=		0.74	
16	Total							$46.37	($1.26)
17									-2.65%
18									
19	Rate C @ 341.8 Ccf						CURRENT	PROPOSED	CHANGE
20	Customer charge						$ 38.04		
21	Consumption charge	342	CCF	X	$0.05748	=	19.64		
22	Rider GCR Part A	342	CCF	X	$0.45750	=	156.36		
23	Rider GCR Part B	342	CCF	X	$0.09611	=	32.85		
24	Subtotal						$246.89		
25	Revenue-related Tax Reimbursement	$246.89		X	0.01620	=	4.00		
26	Total						$250.89		
27									
28	Customer charge							$ 34.72	
29	Consumption charge	342	CCF	X	$0.06589	=		22.52	
30	Rider GCR Part A	342	CCF	X	$0.45750	=		156.36	
31	Rider GCR Part B	342	CCF	X	$0.09611	=		32.85	
32	Subtotal							$246.45	
33	Revenue-related Tax Reimbursement	$246.45		X	0.01620	=		3.99	
34	Total							$250.44	($0.45)
35									-0.18%

	Base	GCR	FF&TAX	Total
Current	$20.78	26.09	0.76	47.63
Proposed	$19.54	26.09	0.74	46.37
	(1.24)	0.00	(0.02)	(1.26)
	-5.97%	0.00%	-2.63%	-2.65%

	Base	GCR	FF&TAX	Total
Current	$ 57.68	189.21	4.00	250.89
Proposed	$57.24	189.21	3.99	250.44
	(0.44)	0.00	(0.01)	(0.45)
	-0.76%	0.00%	-0.25%	-0.18%

ATMOS ENERGY CORP., MID-TEX DIVISION
AVERAGE BILL COMPARISON - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Rate I @ 3897 MMBTU						CURRENT	PROPOSED	CHANGE	
Customer charge						$ 678.33			
Consumption charge	1,500	MMBTU	X	$0.1373	=	205.95			
Consumption charge	2,397	MMBTU	X	$0.0999	=	239.48			
Consumption charge	0	MMBTU	X	$0.0159	=	0.00			
Rider GCR Part A	3,897	MMBTU	X	$0.4685	=	1,825.78			
Rider GCR Part B	3,897	MMBTU	X	$0.2014	=	784.96			
Subtotal						$3,734.50			
Revenue-related Tax Reimbursement	$3,734.50		X	0.01620	=	60.49			
Total						$3,794.99			
Customer charge							$ 600.00		
Consumption charge	1,500	MMBTU	X	$0.2473	=		370.95		
Consumption charge	2,397	MMBTU	X	$0.1812	=		434.38		
Consumption charge	0	MMBTU	X	$0.0389	=		0.00		
Rider GCR Part A	3,897	MMBTU	X	$0.4685	=		1,825.78		
Rider GCR Part B	3,897	MMBTU	X	$0.2014	=		784.96		
Subtotal							$4,016.07		
Revenue-related Tax Reimbursement	$4,016.07		X	0.01620	=		65.06		
Total							$4,081.13	$286.14	286.14
								7.54%	7.54%

	Base	GCR	FF&TAX	Total
Current	$1,123.76	2,610.74	60.49	3,794.99
Proposed	$1,405.33	2,610.74	65.06	4,081.13
	281.57	0.00	4.57	286.14
	25.06%	0.00%	7.55%	7.54%
	16.70%	0.00%	6.44%	6.44%

Rate T @ 3897 MMBTU						CURRENT	PROPOSED	CHANGE	
Customer charge						$ 678.33			
Consumption charge	1,500	MMBTU	X	$0.1373	=	205.95			
Consumption charge	2,397	MMBTU	X	$0.0999	=	239.48			
Consumption charge	0	MMBTU	X	$0.0159	=	0.00			
Rider GCR Part B	3,897	MMBTU	X	$0.2014	=	784.96			
Subtotal						$1,908.72			
Revenue-related Tax Reimbursement	$1,908.72		X	0.01620	=	30.92			
Total						$1,939.64			
Customer charge							$ 600.00		
Consumption charge	1,500	MMBTU	X	$0.2473	=		370.95		
Consumption charge	2,397	MMBTU	X	$0.1812	=		434.38		
Consumption charge	0	MMBTU	X	$0.0389	=		0.00		
Rider GCR Part B	3,897	MMBTU	X	$0.2014	=		784.96		
Subtotal							$2,190.29		
Revenue-related Tax Reimbursement	$2,190.29		X	0.01620	=		35.48		
Total							$2,225.77	$286.13	286.13
								14.75%	14.75%

	Base	GCR	FF&TAX	Total
Current	$1,123.76	784.96	30.92	1,939.64
Proposed	$1,405.33	784.96	35.48	2,225.77
	281.57	0.00	4.56	286.13
	25.06%	0.00%	14.75%	14.75%
	16.70%	0.00%	6.44%	6.44%

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY PROOF OF REVENUE AT PROPOSED RATES - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line	Description		Total	Reference
	(a)		(b)	(c)
	Rate R			
1	Rate Characteristics:			
2	Customer Charge	$	17.70	Rate Design
3				
4	Consumption Charge ($/Ccf)		$0.04172	Rate Design
5				
6	Rider GCR Part A		$0.45750	Schedule H
7	Rider GCR Part B		$0.13281	Schedule I
8				
9	Billing Units (1):			
10	Bills		17,314,932	WP_J-1 Page 1 Col. (b) Ln. 11
11	Total CCF		766,043,261	WP_J-1 Page 1 Col. (b) Ln. 12
12				
13	Proposed Revenue:			
14	Customer Charge	$	306,474,296	Ln 2 times Ln 10
15	Consumption Charge		31,959,325	Ln 4 times Ln 11
16	Base Revenue	$	338,433,621	Ln 14 plus Ln 15
17	Rider GCR Part A		350,465,430	Ln 6 times Ln 11
18	Rider GCR Part B		101,740,497	Ln 7 times Ln 11
19	Subtotal	$	790,639,548	Sum Ln 16 through Ln 18
20	Revenue Related Taxes		53,302,318	Ln 19 times WP_5.1 excel cell G36
21				
22	Total Proposed Revenue- Rate R	$	843,941,866	Ln 19 plus Ln 20
23				
24	Note 1: See Billing Determinants Study for details.			
	Rate C			
1	Rate Characteristics:			
2	Customer Charge	$	34.72	Rate Design
3				
4	Consumption Charge ($/Ccf)		$0.06589	Rate Design
5				
6	Rider GCR Part A		$0.45750	Schedule H
7	Rider GCR Part B		$0.09611	Schedule I
8				
9	Billing Units (1):			
10	Bills		1,471,479	WP_J-1 Page 2 Col. (b) Ln. 11
11	Total CCF		502,902,414	WP_J-1 Page 2 Col. (b) Ln. 12
12				
13	Proposed Revenue:			
14	Customer Charge	$	51,089,751	Ln 2 times Ln 10
15	Consumption Charge		33,136,240	Ln 4 times Ln 11
16	Base Revenue	$	84,225,991	Ln 14 plus Ln 15
17	Rider GCR Part A		230,078,273	Ln 6 times Ln 11
18	Rider GCR Part B		48,332,858	Ln 7 times Ln 11
19	Subtotal	$	362,637,122	Sum Ln 16 through Ln 18
20	Revenue Related Taxes		24,447,802	Ln 19 times WP_5.1 excel cell G36
21				
22	Total Proposed Revenue- Rate C	$	387,084,924	Ln 19 plus Ln 20
23				
24	Note 1: See Billing Determinants Study for details.			

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY PROOF OF REVENUE AT PROPOSED RATES - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line	Description (a)		Total (b)	Reference (c)
	Rate I &T			
1	Rate Characteristics:			
2	Customer Charge	$	600.00	Rate Design
3				
4	Block 1 ($/MMBTU)		$0.2473	Rate Design
5	Block 2 ($/MMBTU)		$0.1812	Rate Design
6	Block 3 ($/MMBTU)		$0.0389	Rate Design
7				
8				
9				
10				
11				
12	Rider GCR Part A		$4.5750	Schedule H
13	Rider GCR Part B		$0.2014	Schedule I
14				
15				
16	Billing Units (1):			
17	Bills		10,380	WP_J-1 Page 3 Col. (b) Ln. 18
18	Block 1		9,678,031	WP_J-1 Page 3 Col. (b) Ln. 19
19	Block 2		11,745,997	WP_J-1 Page 3 Col. (b) Ln. 20
20	Block 3		19,029,227	WP_J-1 Page 3 Col. (b) Ln. 21
21	Total MMBTU		40,453,255	
22				
23	Sales Volumes		1,689,180	WP_J-1
24				
25	Proposed Revenue:			
26	Customer Charge	$	6,228,000	Ln 2 times Ln 17
27	Block 1		2,393,377	Ln 4 times Ln 18
28	Block 2		2,128,375	Ln 5 times Ln 19
29	Block 3		740,237	Ln 6 times Ln 20
30	Base Revenue	$	11,489,989	Sum Ln 26 through Ln 29
31	Rider GCR Part A		7,546,887	Ln 12 times Ln 23
32	Rider GCR Part B		8,147,870	Ln 13 times Ln 21
33	Subtotal	$	27,184,746	Sum Ln 30 through Ln 32
34	Revenue Related Taxes		1,832,706	Ln 33 times WP_5.1 excel cell G36
35				
36	Total Proposed Revenue- Rate I&T	$	29,017,452	Ln 33 plus Ln 34

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF PROPOSED REVENUES BY AREA - RATE R - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Customer Charges	Customer Charge Revenue	Adjusted Volume	Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Proposed Revenue	Amount Change	Percentage Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	AFFECTED CITIES	14,339,989	$ 253,817,814	617,182,352	$ 25,748,848	$ 279,566,661	$ 282,361,440	$ 81,969,834	$ 643,897,936	$ 43,409,481	$ 687,307,417	$ (18,850,962)	-2.67%
2	UNINCORPORATED	536,843	9,502,113	20,295,156	846,714	10,348,827	9,285,051	2,695,460	22,329,338	1,505,370	23,834,708	(701,429)	-2.86%
3	DALLAS ICL	2,438,100	43,154,370	128,565,753	5,363,763	48,518,133	58,818,939	17,075,202	124,412,275	8,387,466	132,799,741	(3,241,132)	-2.38%
4													
5	TOTAL	17,314,932	$ 306,474,296	766,043,261	$ 31,959,325	$ 338,433,621	$ 350,465,430	$ 101,740,497	$ 790,639,548	$ 53,302,318	$ 843,941,866	$ (22,793,523)	-2.63%

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF PROPOSED REVENUES BY AREA - RATE C - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Customer Charges	Customer Charge Revenue	Adjusted Volume	Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Proposed Revenue	Amount Change	Percentage Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	AFFECTED CITIES	1,205,206	$ 41,844,748	381,885,224	$ 25,162,417	$ 67,007,165	$ 174,712,808	$ 36,702,159	$ 278,422,132	$ 18,770,304	$ 297,192,436	$ (842,863)	-0.28%
2	UNINCORPORATED	25,229	875,955	7,434,989	489,891	1,365,847	3,401,514	714,561	5,481,921	369,573	5,851,494	(22,664)	-0.39%
3	DALLAS ICL	241,044	8,369,048	113,582,201	7,483,931	15,852,979	51,963,952	10,916,138	78,733,069	5,307,925	84,040,994	165,407	0.20%
4													
5	TOTAL	1,471,479	$ 51,089,751	502,902,414	$ 33,136,240	$ 84,225,991	$ 230,078,273	$ 48,332,858	$ 362,637,122	$ 24,447,802	$ 387,084,924	$ (700,120)	-0.18%

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF PROPOSED REVENUES BY AREA - RATE I&T - BASE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Meter Charges	Customer Charge Revenue	Sales Volume	Transportation Volume	Total Volume	Volume Block 1	Volume Block 2	Volume Block 3	Consumption Revenue Block 1	Consumption Revenue Block 2	Consumption Revenue Block 3	Total Consumption Revenue	Base Rate Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	AFFECTED CITIES	8,460	$ 5,076,000	1,329,031	28,569,092	29,898,123	7,892,879	8,864,076	13,141,168	$ 1,951,909	$ 1,606,171	$ 511,191	$ 4,069,271	$ 9,145,271
2	UNINCORPORATED	420	252,000	120,004	2,006,272	2,126,276	366,981	488,772	1,270,523	90,754	88,565	49,423	228,743	480,743
3	DALLAS ICL	1,500	900,000	240,145	8,188,711	8,428,856	1,418,171	2,393,149	4,617,536	350,714	433,639	179,622	963,974	1,863,974
4														
5	TOTAL	8,880	$ 6,228,000	1,449,035	38,764,075	40,453,255	9,678,031	11,745,997	19,029,227	$ 2,393,377	$ 2,128,375	$ 740,237	$ 5,261,989	$ 11,489,989

Part A (o)	Part B (p)	Subtotal (q)	Rider FF & Rider TAX (r)	Proposed Revenue (s)	Amount Change (t)	Percentage Change (u)
$ 5,937,820	$ 6,021,914	$ 21,105,005	$ 1,422,830	$ 22,527,835	$ 1,311,259	6.18%
536,152	428,263	1,445,158	97,428	1,542,585	81,581	5.58%
1,072,915	1,697,693	4,634,583	312,448	4,947,032	362,143	7.90%
$ 7,546,887	$ 8,147,870	$ 27,184,746	$ 1,832,706	$ 29,017,452	$ 1,754,982	6.44%

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY PROOF OF REVENUE AT CURRENT RATES - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line	Description (a)	Total (b)	Reference (c)
	Rate R		
1	Rate Characteristics:		
2	Customer Charge	$7.50	CY2010 RRM Settlement
3			
4			
5	Consumption Charge ($/Ccf)	$0.25116	CY2010 RRM Settlement
6			
7	Rider GCR Part A	$0.45750	Schedule H
8	Rider GCR Part B	$0.13281	Schedule I
9			
10	Billing Units (1):		
11	Bills	17,314,932	Billing Determinants Study
12	Total Ccf	766,043,261	Billing Determinants Study
13			
14	Present Revenue:		
15	Customer Charge	$ 129,861,990	Ln 2 times Ln 11
16			
17	Consumption Charge	192,399,425	Ln 5 times Ln 12
18	Base Revenue	$ 322,261,415	Ln 15 plus Ln 17
19	Rider GCR Part A	350,465,430	Ln 7 times Ln 12
20	Rider GCR Part B	101,740,497	Ln 8 times Ln 12
21	Subtotal	$ 774,467,342	Sum Ln 18 through Ln 20
22	Revenue Related Taxes	52,212,041	Ln 21 times WP_5.1 excel cell G36
23			
24	Total Present Revenue- Rate R	$ 826,679,383	Ln 21 plus Ln 22
25			
26	Note 1: See Billing Determinants Study for details.		

Line	Description (a)	Total (b)	Reference (c)
	Rate C		
1	Rate Characteristics:		
2	Customer Charge	$16.75	CY2010 RRM Settlement
3			
4			
5	Consumption Charge ($/Ccf)	$0.10217	CY2010 RRM Settlement
6			
7	Rider GCR Part A	$0.45750	Schedule H
8	Rider GCR Part B	$0.09611	Schedule I
9			
10	Billing Units (1):		
11	Bills	1,471,479	Billing Determinants Study
12	Total CCF	502,902,414	Billing Determinants Study
13			
14	Present Revenue:		
15	Customer Charge	$ 24,647,273	Ln 2 times Ln 11
16			
17	Consumption Charge	51,381,540	Ln 5 times Ln 12
18	Base Revenue	$ 76,028,813	Ln 15 plus Ln 17
19	Rider GCR Part A	230,078,273	Ln 7 times Ln 12
20	Rider GCR Part B	48,332,858	Ln 8 times Ln 12
21	Subtotal	$ 354,439,944	Sum Ln 18 through Ln 20
22	Revenue Related Taxes	23,895,175	Ln 21 times WP_5.1 excel cell G36
23			
24	Total Present Revenue- Rate C	$ 378,335,119	Ln 21 plus Ln 22
25			
26	Note 1: See Billing Determinants Study for details.		

ATMOS ENERGY CORP., MID-TEX DIVISION
SUMMARY PROOF OF REVENUE AT CURRENT RATES - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line	Description (a)		Total (b)	Reference (c)
	Rate I &T			
1	Rate Characteristics:			
2	Customer Charge		$450.00	CY2010 RRM Settlement
3				
4				
5	Block 1 ($/MMBTU)		$0.2750	CY2010 RRM Settlement
6	Block 2 ($/MMBTU)		$0.2015	CY2010 RRM Settlement
7	Block 3 ($/MMBTU)		$0.0433	CY2010 RRM Settlement
8				
9	Rider GCR Part A		$4.57501	Schedule H
10	Rider GCR Part B		$0.20141	Schedule I
11				
12	Consumption Characteristics:			
13	Block 1		0.23924	(1)
14	Block 2		0.29036	(1)
15	Block 3		0.47040	(1)
16				
17	Billing Units (1):			
18	Bills		10,380	Billing Determinants Study
19	Block 1		9,678,031	Billing Determinants Study
20	Block 2		11,745,997	Billing Determinants Study
21	Block 3		19,029,227	Billing Determinants Study
22	Total MMBTU		40,453,255	
23				
24	Sales Volumes		1,689,180	Billing Determinants Study
25				
26	Present Revenue:			
27	Customer Charge	$	4,671,000	Ln 2 time Ln 18
28				
29	Block 1		2,661,459	Ln 5 times Ln 19
30	Block 2		2,366,818	Ln 6 times Ln 20
31	Block 3		823,966	Ln 7 times Ln 21
32	Base Revenue	$	10,523,242	Sum Ln 27 through Ln 31
33	Rider GCR Part A		7,546,887	Ln 9 times Ln 24
34	Rider GCR Part B		8,147,870	Ln 10 times Ln 22
35	Subtotal	$	26,218,000	Sum Ln 32 through Ln 34
36	Revenue Related Taxes		1,767,531	Ln 35 times WP_5.1 excel cell G36
37				
38	Total Present Revenue- Rate I&T	$	27,985,531	Ln 35 plus Ln 36
39				
40	Note 1: See Billing Determinants Study for details.			

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF CURRENT REVENUES BY AREA - RATE R - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Customer Charges	Customer Charge Revenue	Per Book Volume	Adjusted Volume	Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Current Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	AFFECTED CITIES	14,339,989	$ 107,549,921	621,660,902	617,182,352	$ 155,011,519	$ 262,561,441	$ 282,361,440	$ 81,969,834	$ 626,892,715	$ 42,263,044.85	$ 669,155,760
2	UNINCORPORATED	536,843	4,026,319	20,407,073	20,295,156	5,097,331	9,123,650	9,285,051	2,695,460.33	21,104,161	1,422,773.13	22,526,934
3	DALLAS ICL	2,438,100	18,285,750	130,509,900	128,565,753	32,290,575	50,576,325	58,818,939	17,075,202.19	126,470,466	8,526,222.82	134,996,689
4												
5	TOTAL	17,314,932	$ 129,861,990	772,577,876	766,043,261	$ 192,399,425	$ 322,261,415	$ 350,465,430	$ 101,740,497	$ 774,467,342	$ 52,212,041	$ 826,679,383
6												
7												
8												
9	Ratios:											
10	AFFECTED CITIES				80.57%							
11	UNINCORPORATED				2.65%							
12	DALLAS ICL				16.78%							
13	TOTAL				100.00%							

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF CURRENT REVENUES BY AREA - RATE C - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Customer Charges	Customer Charge Revenue	Per Book Volume	Adjusted Volume	Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Current Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	AFFECTED CITIES	1,205,206	$20,187,198	379,651,812	381,885,224	$39,017,213	$59,204,412	$174,712,808	$ 36,702,159	$270,619,378	$18,244,268	$288,863,647
2	UNINCORPORATED	25,229	422,588	7,367,385	7,434,989	759,633	1,182,221	3,401,514	714,561	5,298,295	357,194	5,655,489
3	DALLAS ICL	241,044	4,037,487	115,303,938	113,582,201	11,604,694	15,642,181	51,963,952	10,916,138	78,522,271	5,293,713	83,815,984
4												
5	TOTAL	1,471,479	$24,647,273	502,323,136	502,902,414	$51,381,540	$76,028,813	$230,078,273	$ 48,332,858	$354,439,944	$23,895,175	$378,335,119
6												
7												
8												
9	Ratios:											
10	AFFECTED CITIES				75.94%							
11	UNINCORPORATED				1.48%							
12	DALLAS ICL				22.59%							
13	TOTAL				100.00%							

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF CURRENT REVENUES BY AREA - RATE I&T - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Meter Charges	Customer Charge Revenue	Sales Volume	Transportation Volume	Total Volume	Volume Block 1	Volume Block 2	Volume Block 3	Consumption Revenue Block 1	Consumption Revenue Block 2	Consumption Revenue Block 3	Total Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Current Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
1	AFFECTED CITIES	8,460	$3,807,000	1,329,031	28,569,092	29,898,123	7,892,879	8,864,076	13,141,168	$2,170,542	$1,786,111	$ 569,013	$4,525,666	$ 8,332,666	$5,937,820	$ 6,021,914	$20,292,400	$ 1,368,047	$21,660,447
2	UNINCORPORATED	420	189,000	120,004	2,006,272	2,126,276	366,981	488,772	1,270,523	100,920	98,488	55,014	254,421	443,421	536,152	428,263	1,407,835	$ 94,912	1,502,747
3	DALLAS ICL	1,500	675,000	240,145	8,188,711	8,428,856	1,418,171	2,393,149	4,617,536	389,997	482,220	199,939	1,072,156	1,747,156	1,072,915	1,697,693	4,517,765	$ 304,573	4,822,338
4																			
5	TOTAL	10,380	$4,671,000	1,689,180	38,764,075	40,453,255	9,678,031	11,745,997	19,029,227	$2,661,459	$2,366,818	$ 823,966	$5,852,242	$10,523,242	$7,546,887	$ 8,147,870	$26,218,000	$ 1,767,531	$27,985,531

ATMOS ENERGY CORP., MID-TEX DIVISION
TYPICAL BILL COMPARISON - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line								July 5, 2012	
1	**Rate R @ 60 Ccf**						CURRENT	PROPOSED	CHANGE
2	Customer charge						$7.50		
3	Consumption charge	60	CCF	X	$0.25116	=	15.07		
4	Rider GCR Part A	60	CCF	X	$0.45750	=	27.45		
5	Rider GCR Part B	60	CCF	X	$0.13281	=	7.97		
6	Subtotal						$57.99		
7	Rider FF & Rider TAX	$57.99		X	0.06742	=	3.91		
8	Total						$61.90		
9									
10	Customer charge							$ 17.70	
11	Consumption charge	60	CCF	X	$0.04172	=		2.50	
12	Rider GCR Part A	60	CCF	X	$0.45750	=		27.45	
13	Rider GCR Part B	60	CCF	X	$0.13281	=		7.97	
14	Subtotal							$55.62	
15	Revenue-related Tax Reimbursement	$55.62		X	0.06742	=		3.75	
16	Total							$59.37	($2.53)
17									-4.09%
18									
19	**Rate C @ 300 Ccf**						CURRENT	PROPOSED	CHANGE
20	Customer charge						$16.75		
21	Consumption charge	300	CCF	X	$0.10217	=	30.65		
22	Rider GCR Part A	300	CCF	X	$0.45750	=	137.25		
23	Rider GCR Part B	300	CCF	X	$0.09611	=	28.83		
24	Subtotal						$213.48		
25	Revenue-related Tax Reimbursement	$213.48		X	0.06742	=	14.39		
26	Total						$227.87		
27									
28	Customer charge							$ 34.72	
29	Consumption charge	300	CCF	X	$0.06589	=		19.77	
30	Rider GCR Part A	300	CCF	X	$0.45750	=		137.25	
31	Rider GCR Part B	300	CCF	X	$0.09611	=		28.83	
32	Subtotal							$220.57	
33	Revenue-related Tax Reimbursement	$220.57		X	0.06742	=		14.87	
34	Total							$235.44	$7.57
35									3.32%
36	**Rate I @ 300 MMBTU**						CURRENT	PROPOSED	CHANGE
37	Customer charge						$450.00		
38	Consumption charge	300	MMBTU	X	$0.2750	=	82.50		
39	Consumption charge	0	MMBTU	X	$0.2015	=	0.00		
40	Consumption charge	0	MMBTU	X	$0.0433	=	0.00		

ATMOS ENERGY CORP., MID-TEX DIVISION
TYPICAL BILL COMPARISON - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

41	Rider GCR Part A	300	MMBTU	X	$0.4685	=	140.54			
42	Rider GCR Part B	300	MMBTU	X	$0.2014	=	60.42			
43	Subtotal						$733.46			
44	Revenue-related Tax Reimbursement	$733.46		X	0.06742	=	49.45			
45	Total						$782.91			
46										
47	Customer charge							$	600.00	
48	Consumption charge	300	MMBTU	X	$0.2473	=			74.19	
49	Consumption charge	0	MMBTU	X	$0.1812	=			0.00	
50	Consumption charge	0	MMBTU	X	$0.0389	=			0.00	
51	Rider GCR Part A	300	MMBTU	X	$0.4685	=			140.54	
52	Rider GCR Part B	300	MMBTU	X	$0.2014	=			60.42	
53	Subtotal								$875.15	
54	Revenue-related Tax Reimbursement	$875.15		X	0.06742	=			59.00	
55	Total								$934.15	$151.24
56										19.32%
57	**Rate T @ 300 MMBTU**						**CURRENT**		**PROPOSED**	**CHANGE**
58	Customer charge						$450.00			
59	Consumption charge	300	MMBTU	X	$0.2750	=	82.50			
60	Consumption charge	0	MMBTU	X	$0.2015	=	0.00			
61	Consumption charge	0	MMBTU	X	$0.0433	=	0.00			
62	Rider GCR Part B	300	MMBTU	X	$0.2014	=	60.42			
63	Subtotal						$592.92			
64	Revenue-related Tax Reimbursement	$592.92		X	0.06742	=	39.97			
65	Total						$632.89			
66										
67	Customer charge							$	600.00	
68	Consumption charge	300	MMBTU	X	$0.2473	=			74.19	
69	Consumption charge	0	MMBTU	X	$0.1812	=			0.00	
70	Consumption charge	0	MMBTU	X	$0.0389	=			0.00	
71	Rider GCR Part B	300	MMBTU	X	$0.2014	=			60.42	
72	Subtotal								$734.61	
73	Revenue-related Tax Reimbursement	$734.61		X	0.06742	=			49.52	
74	Total								$784.13	$151.24
75										23.90%

ATMOS ENERGY CORP., MID-TEX DIVISION
AVERAGE BILL COMPARISON - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line							CURRENT	July 5, 2012 PROPOSED	CHANGE
1	**Rate R @ 44.2 Ccf**								
2	Customer charge						$7.50		
3	Consumption charge	44	CCF	X	$0.25116	=	11.10		
4	Rider GCR Part A	44	CCF	X	$0.45750	=	20.22		
5	Rider GCR Part B	44	CCF	X	$0.13281	=	5.87		
6	Subtotal						$44.69		
7	Rider FF & Rider TAX		$44.69	X	0.06742	=	3.01		
8	Total						$47.70		
9									
10	Customer charge							$ 17.70	
11	Consumption charge	44	CCF	X	$0.04172	=		1.84	
12	Rider GCR Part A	44	CCF	X	$0.45750	=		20.22	
13	Rider GCR Part B	44	CCF	X	$0.13281	=		5.87	
14	Subtotal							$45.63	
15	Revenue-related Tax Reimbursement		$45.63	X	0.06742	=		3.08	
16	Total							$48.71	$1.01
17									2.12%
18									

	Base	GCR	FF&TAX	Total
Current	$18.60	26.09	3.01	47.70
Proposed	$19.54	26.09	3.08	48.71
	0.94	0.00	0.07	1.01
	5.05%	0.00%	2.33%	2.12%

Line							CURRENT	PROPOSED	CHANGE
19	**Rate C @ 341.8 Ccf**								
20	Customer charge						$16.75		
21	Consumption charge	342	CCF	X	$0.10217	=	34.92		
22	Rider GCR Part A	342	CCF	X	$0.45750	=	156.36		
23	Rider GCR Part B	342	CCF	X	$0.09611	=	32.85		
24	Subtotal						$240.88		
25	Revenue-related Tax Reimbursement		$240.88	X	0.06742	=	16.24		
26	Total						$257.12		
27									
28	Customer charge							$ 34.72	
29	Consumption charge	342	CCF	X	$0.06589	=		22.52	
30	Rider GCR Part A	342	CCF	X	$0.45750	=		156.36	
31	Rider GCR Part B	342	CCF	X	$0.09611	=		32.85	
32	Subtotal							$246.45	
33	Revenue-related Tax Reimbursement		$246.45	X	0.06742	=		16.61	
34	Total							$263.06	$5.94
35									2.31%

	Base	GCR	FF&TAX	Total
Current	$ 51.67	189.21	16.24	257.12
Proposed	$57.24	189.21	16.61	263.06
	5.57	0.00	0.37	5.94
	10.78%	0.00%	2.28%	2.31%

ATMOS ENERGY CORP., MID-TEX DIVISION
AVERAGE BILL COMPARISON - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

						CURRENT	PROPOSED	CHANGE	
Rate I @ 3897 MMBTU									
Customer charge						$450.00			
Consumption charge	1,500	MMBTU	X	$0.2750	=	412.50			
Consumption charge	2,397	MMBTU	X	$0.2015	=	483.04			
Consumption charge	0	MMBTU	X	$0.0433	=	0.00			
Rider GCR Part A	3,897	MMBTU	X	$0.4685	=	1,825.78			
Rider GCR Part B	3,897	MMBTU	X	$0.2014	=	784.96			
Subtotal						$3,956.28			
Revenue-related Tax Reimbursement	$3,956.28		X	0.06742	=	266.72			
Total						$4,223.00			
Customer charge							$ 600.00		
Consumption charge	1,500	MMBTU	X	$0.2473	=		370.95		
Consumption charge	2,397	MMBTU	X	$0.1812	=		434.38		
Consumption charge	0	MMBTU	X	$0.0389	=		0.00		
Rider GCR Part A	3,897	MMBTU	X	$0.4685	=		1,825.78		
Rider GCR Part B	3,897	MMBTU	X	$0.2014	=		784.96		
Subtotal							$4,016.07		
Revenue-related Tax Reimbursement	$4,016.07		X	0.06742	=		270.75		
Total							$4,286.82	$63.82	63.82
								1.51%	1.51%

	Base	GCR	FF&TAX	Total
Current	$1,345.54	2,610.74	266.72	4,223.00
Proposed	$1,405.33	2,610.74	270.75	4,286.82
	59.79	0.00	4.03	63.82
	4.44%	0.00%	1.51%	1.51%
	9.19%	0.00%	3.69%	3.69%

						CURRENT	PROPOSED	CHANGE	
Rate T @ 3897 MMBTU									
Customer charge						$450.00			
Consumption charge	1,500	MMBTU	X	$0.2750	=	412.50			
Consumption charge	2,397	MMBTU	X	$0.2015	=	483.04			
Consumption charge	0	MMBTU	X	$0.0433	=	0.00			
Rider GCR Part B	3,897	MMBTU	X	$0.2014	=	784.96			
Subtotal						$2,130.50			
Revenue-related Tax Reimbursement	$2,130.50		X	0.06742	=	143.63			
Total						$2,274.13			
Customer charge							$ 600.00		
Consumption charge	1,500	MMBTU	X	$0.2473	=		370.95		
Consumption charge	2,397	MMBTU	X	$0.1812	=		434.38		
Consumption charge	0	MMBTU	X	$0.0389	=		0.00		
Rider GCR Part B	3,897	MMBTU	X	$0.2014	=		784.96		
Subtotal							$2,190.29		
Revenue-related Tax Reimbursement	$2,190.29		X	0.06742	=		147.66		
Total							$2,337.95	$63.82	63.82
								2.81%	2.81%

	Base	GCR	FF&TAX	Total
Current	$1,345.54	784.96	143.63	2,274.13
Proposed	$1,405.33	784.96	147.66	2,337.95
	59.79	0.00	4.03	63.82
	4.44%	0.00%	2.81%	2.81%
	9.19%	0.00%	3.69%	3.69%

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF PROPOSED REVENUES BY AREA - RATE R - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Customer Charges	Customer Charge Revenue	Adjusted Volume	Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Proposed Revenue	Amount Change	Percentage Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	AFFECTED CITIES	14,339,989	$ 253,817,814	617,182,352	$ 25,748,848	$ 279,566,661	$ 282,361,440	$ 81,969,834	$ 643,897,936	$ 43,409,481	$ 687,307,417	$ 18,151,657	2.71%
2	UNINCORPORATED	536,843	9,502,113	20,295,156	846,714	10,348,827	9,285,051	2,695,460	22,329,338	1,505,370	23,834,708	1,307,774	5.81%
3	DALLAS ICL	2,438,100	43,154,370	128,565,753	5,363,763	48,518,133	58,818,939	17,075,202	124,412,275	8,387,466	132,799,741	(2,196,948)	-1.63%
4													
5	TOTAL	17,314,932	$ 306,474,296	766,043,261	$ 31,959,325	$ 338,433,621	$ 350,465,430	$ 101,740,497	$ 790,639,548	$ 53,302,318	$ 843,941,866	$ 17,262,483	2.09%

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF PROPOSED REVENUES BY AREA - RATE C - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Customer Charges	Customer Charge Revenue	Adjusted Volume	Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Proposed Revenue	Amount Change	Percentage Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	AFFECTED CITIES	1,205,206	$ 41,844,748	381,885,224	$ 25,162,417	$ 67,007,165	$ 174,712,808	$ 36,702,159	$ 278,422,132	$ 18,770,304	$ 297,192,436	$ 8,328,790	2.88%
2	UNINCORPORATED	25,229	875,955	7,434,989	489,891	1,365,847	3,401,514	714,561	5,481,921	369,573	5,851,494	196,006	3.47%
3	DALLAS ICL	241,044	8,369,048	113,582,201	7,483,931	15,852,979	51,963,952	10,916,138	78,733,069	5,307,925	84,040,994	225,010	0.27%
4													
5	TOTAL	1,471,479	$ 51,089,751	502,902,414	$ 33,136,240	$ 84,225,991	$ 230,078,273	$ 48,332,858	$ 362,637,122	$ 24,447,802	$ 387,084,924	$ 8,749,805	2.31%

ATMOS ENERGY CORP., MID-TEX DIVISION
CALCULATION OF PROPOSED REVENUES BY AREA - RATE I&T - BASE RATES - APPEALS
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Area	Adjusted Meter Charges	Customer Charge Revenue	Sales Volume	Transportation Volume	Total Volume	Volume Block 1	Volume Block 2	Volume Block 3	Consumption Revenue Block 1	Consumption Revenue Block 2	Consumption Revenue Block 3	Total Consumption Revenue	Base Rate Revenue	Part A	Part B	Subtotal	Rider FF & Rider TAX	Proposed Revenue	Amount Change	Percentage Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	AFFECTED CITIES	8,460	$ 5,076,000	1,329,031	28,569,092	29,898,123	7,892,879	8,864,076	13,141,168	$ 1,951,909	$ 1,606,171	$ 511,191	$ 4,069,271	$ 9,145,271	$ 5,937,820	$ 6,021,914	$ 21,105,005	$ 1,422,830	$ 22,527,835	$ 867,389	4.00%
2	UNINCORPORATED	420	252,000	120,004	2,006,272	2,126,276	366,981	488,772	1,270,523	90,754	88,565	49,423	228,743	480,743	536,152	428,263	1,445,158	97,428	1,542,585	39,838	2.65%
3	DALLAS ICL	1,500	900,000	240,145	8,188,711	8,428,856	1,418,171	2,393,149	4,617,536	350,714	433,639	179,622	963,974	1,863,974	1,072,915	1,697,693	4,634,583	312,448.36	4,947,032	124,694	2.59%
4																					
5	TOTAL	8,880	$ 6,228,000	1,449,035	38,764,075	40,453,255	9,678,031	11,745,997	19,029,227	$ 2,393,377	$ 2,128,375	$ 740,237	$ 5,261,989	$ 11,489,989	$ 7,546,887	$ 8,147,870	$ 27,184,746	$ 1,832,706	$ 29,017,452	$ 1,031,921	3.69%

Atmos Energy Corp., Mid-Tex Division
2012 Statement of Intent
Rate Design

	Total	Residential	Commercial	Industrial & Transport
Appeal CCOS Net Revenue Requirement	$ 434,145,424	$ 338,431,486	$ 84,223,622	$ 11,490,316
Original Filing CCOS Net Revenue Requirement	$ 459,281,751	$ 366,013,687	$ 83,419,058	$ 9,849,006
Change to Residential Class		$ (27,582,201)		
% of Revenue Requirement Excluding Residential			88.00%	12.00%
Adjustment to Appeal CCOS Net Revenue Requirement	$ -	$ -	$ -	$ -
Rate Design Net Revenue Requirement	**$ 434,145,424**	**$ 338,431,486**	**$ 84,223,622**	**$ 11,490,316**
Adjusted Number of Bills		17,314,932	1,471,479	10,380
Proposed Customer Charge		**$ 17.70**	**$ 34.72**	**$ 600.00**
Customer Charge Revenue		$ 306,474,296	$ 51,089,751	$ 6,228,000
Revenue to be Collected in Consumption Charge		31,957,189	33,133,871	5,262,316
Volumes				
Tier 1		766,043,261	502,902,414	9,678,031
Tier 2				11,745,997
Tier 3				19,029,227
Consumption Charge per Ccf/MMBtu				
Tier 1		**$ 0.04172**	**$ 0.06589**	**$ 0.2473**
Tier 2				**$ 0.1812**
Tier 3				**$ 0.0389**

ATMOS ENERGY CORP. -- MID-TEX DIVISION
BASE REVENUE REQUIREMENTS ALLOCATION
TYE 9/30/11

		BASE REVENUE REQUIREMENTS ALLOCATION		
Description	Amount	Residential	Commercial	Industrial & Transport
(a)	(b)	(c)	(d)	(e)
1 Operating & Maintenance Expenses	$ 150,139,876	$ 117,821,997	$ 28,208,729	$ 4,109,151
2 Depreciation Expense	92,971,711	74,169,547	16,792,900	2,009,264
3 Taxes Other than Income	26,076,868	20,074,644	5,282,081	720,143
4 Interest on Customer Deposits	26,170	18,552	7,618	-
5 Return on Investment	129,638,514	99,441,226	26,557,747	3,639,541
6 Income Taxes	48,602,650	37,281,414	9,956,739	1,364,497
7 **Total Cost of Service**	**$ 447,455,789**	**$ 348,807,380**	**$ 86,805,815**	**$ 11,842,595**
		77.95%	19.40%	2.65%
8 Revenue Credits	13,310,366	10,375,894	2,582,193	352,279
9 **Base Revenue Requirements**	**$ 434,145,424**	**$ 338,431,486**	**$ 84,223,622**	**$ 11,490,316**

		Total	Residential	Commercial	Industrial & Transport
(a)	Customer Deposit Balances				
	Customer Deposit Balances	$ 34,046,761	$ 24,135,338	$ 9,911,423	-
	Allocation Factor	**100.00%**	**70.89%**	**29.11%**	**0.00%**
(b)	Allocated Rate Base				
	Allocated Rate Base	$ 1,512,985,745	$ 1,160,559,109	$ 309,950,269	$ 42,476,367
	Allocation Factor	**100.00%**	**76.71%**	**20.49%**	**2.81%**
(c)	Allocated Total Cost of Service				
	Total Cost of Service	$ 447,455,789	$ 348,807,380	$ 86,805,815	$ 11,842,595
	Allocation Factor	**100.00%**	**77.95%**	**19.40%**	**2.65%**

ATMOS ENERGY CORP. -- MID-TEX DIVISION
RATE BASE ALLOCATION
TYE 9/30/11

	Description (a)	Amount (b)	Residential (c)	Commercial (d)	Industrial & Transport (e)
			RATE BASE ALLOCATION		
1	**Net Plant:**				
2	Gross Plant	$ 2,862,971,783			
3	Accumulated Depreciation	1,069,874,434			
4	**Net Plant**	**$ 1,793,097,349**	**$ 1,374,107,069**	**$ 369,367,977**	**$ 49,622,303**
5	**Working Capital :**				
6	Cash Working Capital	$ (19,302,670)	$ (15,147,735)	$ (3,626,643)	$ (528,291)
7	Materials & Supplies	850,505	667,432	159,795	23,277
8	Prepayments	10,692,714	8,391,088	2,008,979	292,647
9	Pension Expense Regulatory Asset	1,954,911	1,534,113	367,295	53,504
10	**Working Capital**	**$ (5,804,540)**	**(4,555,102)**	**(1,090,574)**	**(158,863)**
11	**Non-Investor Supplied Capital:**				
12	Customer Deposits	$ 21,808,614	$ 15,459,863	$ 6,348,751	$ -
13	Injuries and Damages Reserve	1,925,776	1,511,249	361,820	52,706
14	Accumulated Deferred Income Taxes	241,322,747	184,933,234	49,711,130	6,678,383
15	Rate Base Adjustments	9,249,927	7,088,511	1,905,433	255,983
16	**Non-Investor Supplied Capital**	**274,307,063**	**208,992,857**	**58,327,134**	**6,987,072**
17	**RATE BASE**	**$ 1,512,985,745**	**$ 1,160,559,109**	**$ 309,950,269**	**$ 42,476,367**

		Total	Residential	Commercial	Industrial & Transport
(a)	Allocated O&M Expenses				
	Allocated O&M Expenses	$ 150,139,876	117,821,997	28,208,729	4,109,151
	Allocation Factor	**100.00%**	**78.47%**	**18.79%**	**2.74%**
(b)	Customer Deposit Balances				
	Customer Deposit Balances	$ 34,046,761	$ 24,135,338	$ 9,911,423	$ -
	Allocation Factor	**100.00%**	**70.89%**	**29.11%**	**0.00%**
(c)	Allocated Net Plant				
	Allocated Net Plant	$ 1,793,097,349	$ 1,374,107,069	$ 369,367,977	$ 49,622,303
	Allocation Factor	**100.00%**	**76.63%**	**20.60%**	**2.77%**

ATMOS ENERGY CORP. -- MID-TEX DIVISION
PLANT ALLOCATION
TYE 9/30/11

			ORIGINAL COST			FUNCTIONALIZATION / CLASSIFICATION			PLANT ALLOCATION		
	Acct. No.	Description	Gross Plant	Accumulated Depreciation	Net Plant	Customer-Related (a)	Capacity-Related (a)	General	Residential	Commercial	Industrial & Transport
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Mid-Tex:**										
2	**Distribution Plant**										
3	374	Land	$ 779,648	$ 7,298	$ 772,350	$ 238,451			$ 218,567	$ 19,621	$ 263
4							$ 533,899		343,312	163,094	27,494
5	374	Land Rights	3,202,299	1,651,163	1,551,135	478,888			438,954	39,406	528
6							1,072,247		689,484	327,546	55,217
7	375	Structures & Improvements	1,468,570	1,328,471	140,099	43,253			39,646	3,559	48
8							96,845		62,274	29,584	4,987
9	376	Mains	1,476,878,143	382,674,635	1,094,203,508	337,817,905			309,647,548	27,797,849	372,509
10							756,385,603		486,376,256	231,057,987	38,951,360
11	378	M&R Station Equipment - General	39,052,296	18,202,077	20,850,219	6,437,173			5,900,382	529,692	7,098
12							14,413,046		9,267,975	4,402,846	742,224
13	379	M&R Station Equipment - City Gate	5,513,898	2,981,446	2,532,453	781,854			716,656	64,336	862
14							1,750,598		1,125,682	534,767	90,150
15	380	Services	758,429,725	449,388,591	309,041,134	309,041,134			283,270,448	25,429,909	340,777
16	381	Meters	161,610,868	69,356,213	92,254,655	92,254,655			67,815,977	22,484,897	1,953,781
17	382	Meter Installations	113,850,895	33,884,709	79,966,185	79,966,185			58,782,779	19,489,872	1,693,534
18	383	House Regulators	47,352,660	12,349,400	35,003,261	35,003,261			25,730,738	8,531,220	741,303
19	385	Industrial M&R Station Equipment	1,280,593	173,954	1,106,639	1,106,639			-	-	1,106,639
20		Total Distribution Plant	$ 2,609,419,594	$ 971,997,957	$ 1,637,421,637	$ 863,169,398	$ 774,252,239	$ -	$ 1,250,426,678	$ 340,906,186	$ 46,088,774
21	**General Plant**										
22	302	Franchises & Consents	18,896	7,231	$ 11,665			$ 11,665	$ 8,940	$ 2,403	$ 323
23	303	Computer Software	3,386,331	3,474,703	(88,372)			(88,372)	(67,722)	(18,204)	(2,446)
24	389	Land	3,982,767	245,810	3,736,957			3,736,957	2,863,748	769,792	103,417
25	390	Structures & Improvements	29,857,249	14,493,418	15,363,830			15,363,830	11,773,788	3,164,863	425,180
26	391	Office Furniture & Equipment	6,459,687	2,395,160	4,064,527			4,064,527	3,114,775	837,270	112,482
27	392	Transportation Equipment	3,284,784	(1,541,204)	4,825,988			4,825,988	3,698,307	994,126	133,555
28	393	Stores Equipment	144,748	15,459	129,289			129,289	99,079	26,633	3,578
29	394	Tools, Shop, and Garage Equipment	11,778,174	941,117	10,837,058			10,837,058	8,304,779	2,232,373	299,905
30	395	Laboratory Equipment	329,367	(6,458)	335,825			335,825	257,353	69,178	9,294
31	396	Power Oper. Tool & Work Equipment	2,267,102	(1,518,906)	3,786,008			3,786,008	2,901,337	779,896	104,774
32	397	Radio Communication Equipment	8,167,925	1,506,837	6,661,088			6,661,088	5,104,602	1,372,147	184,339
33	398	Miscellaneous Equipment	18,571,170	15,049,678	3,521,492			3,521,492	2,698,630	725,408	97,454
34	399	Non-Mainframe Computer Equipment	11,460,720	789,186	10,671,534			10,671,534	8,177,933	2,198,276	295,325
35	RWIP	Retirement Work in Progress	-	(36,203,431)	36,203,431			36,203,431	27,743,831	7,457,703	1,001,896
36		Total General Plant	$ 99,708,919	$ (351,401)	$ 100,060,320	$ -	$ -	$ 100,060,320	$ 76,679,380	$ 20,611,864	$ 2,769,076
37	**Shared Services Unit:**										
38		**Customer Support**	$ 94,317,551	$ 65,163,949	$ 29,153,602	$ 29,153,602			26,722,507	2,398,948	32,147
39		**General Plant**	59,525,719	33,063,929	26,461,789			26,461,789	20,278,504	5,450,980	732,305
40		Total Shared Services Plant	$ 153,843,269	$ 98,227,878	$ 55,615,391	$ 29,153,602	$ -	$ 26,461,789	$ 47,001,011	$ 7,849,927	$ 764,453
41		**TOTAL PLANT**	$ 2,862,971,783	$ 1,069,874,434	$ 1,793,097,349	$ 892,323,001	$ 774,252,239	$ 126,522,109	**$ 1,374,107,069**	**$ 369,367,977**	**$ 49,622,303**

ATMOS ENERGY CORP. -- MID-TEX DIVISION
PLANT ALLOCATION

		Total	Customer-Related	Capacity-Related	Residential	Commercial	Industrial & Transport
(a)	Accounts 374-379 functionalized between Customer-related and Capacity-related using the following minimum system analysis:						
	Feet of Mains	153,690,240					
	Current Cost of 2" Main per Foot	$ 5.70					
	Current Cost of 2' Main System	876,351,221	876,351,221				
	Current Cost of All Mains in Service	2,838,530,956					
	Remaining Current Cost of Mains	1,962,179,735		1,962,179,735			
	Allocation Factor	**100.00%**	**30.87%**	**69.13%**			
(b)	No. of Customer Locations						
	No. of Customer Locations	1,620,582			1,485,443	133,352	1,787
	Allocation Factor	**100.00%**			**91.66%**	**8.23%**	**0.11%**
(c)	Design Day Demand						
	Design Day Demand (Mcf)	2,097,587			1,348,805	640,763	108,019
	Allocation Factor	**100.00%**			**64.30%**	**30.55%**	**5.15%**
(d)	Meter Investment						
	Meter Investment	$ 343,002,294			$ 252,139,425	$ 83,598,723	$ 7,264,146
	Allocation Factor	**100.00%**			**73.51%**	**24.37%**	**2.12%**
(e)	Direct to Ind. & Trans.						
	Allocation Factor	**100.00%**			**0.00%**	**0.00%**	**100.00%**
(f)	Distribution & Cust. Sup. Plant						
	Total Distribution Plant	$ 1,637,421,637			$ 1,250,426,678	$ 340,906,186	$ 46,088,774
	Customer Support Plant	29,153,602			26,722,507	2,398,948	32,147
	Total	$ 1,666,575,239			$ 1,277,149,185	$ 343,305,134	$ 46,120,921
	Allocation Factor	**100.00%**			**76.63%**	**20.60%**	**2.77%**

ATMOS ENERGY CORP. -- MID-TEX DIVISION
DESIGN DAY DEMAND ANALYSIS
TYE 9/30/11

Class Cost of Service Study - 4
Page 1 of 1

	DESIGN DAY DEMAND	Residential		Commercial		Industrial & Transport		Reference	Description
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Class Adjusted Usage (Mcf)	76,604,326		50,290,241					Billing Determinant Study
2	Annual Days	365		365					
3	Class Daily Usage (Mcf)	209,875		137,781					
4	Adjusted Customers	1,442,911		122,623					Billing Determinant Study
5	Daily use per Customer (Mcf)		0.1455		1.1236				
6	Normal Heating Degree Days	2,086		2,086					Billing Determinant Study
7	Annual Days	365		365					(DFW Airport)
8	Average Daily Heating Degree Days	5.72		5.72					
9	System Design Heating Degree Days	50.00		50.00					GUD No. 9670
10	System Design vs. Average Daily HDDs	44.28		44.28					
11	Use per Customer / HDD Regression Coefficients	0.0206		0.0956				CCS-5	Use per Customer/HDD Regression
12	Adjustment to Daily Use per Customer		0.9129		4.2323				
13	Adjusted Class Design Day Usage		1.0583		5.3560				
14	Adjusted Customers		1,442,911		122,623				Billing Determinant Study
15	**Class Design Day**		1,527,058		656,766		108,233		Billing Determinant Study
16	**Adjustment for Minimum System**								
17	Maximum Hourly Flow per Location (Ccf)	5		5		5			GUD No. 9670
18	Daily Hours	24		24		24			
19	Maximum Hourly Flow per Location (Ccf)	120		120		120			
20	Number of Locations	1,485,443		133,352		1,787			Meter Count & GUD No. 9670
21	Maximum Daily Flow per Hour (Mcf)		(178,253.16)		(16,002)		(214)		
22	**Adjusted Class Design Day (Mcf)**		1,348,805		640,763		108,019		
23	**UPSTREAM PIPELINE FIXED CHARGE ALLOCATION FACTOR:**								
24	Adjusted Class Design Day (Mcf)	1,348,805		640,763		108,019			
25	Mmbtu/Mcf	1.024		1.024		1.024			GUD No. 9670
26	Lost & Unaccounted-for Gas Factor	1.025		1.025		1.025			GUD No. 9670
27	**Upstream MMBtu Demand**		1,415,705		672,545		113,377		
28	**Upstream Pipeline Fixed Charge Allocation Factor**		64.30269%		30.54764%		5.14967%		

ATMOS ENERGY CORP. -- MID-TEX DIVISION
USE PER CUSTOMER / HEATING DEGREE DAY REGRESSION
TYE 9/30/11

Class Cost of Service Study - 5
Page 1 of 1

			RESIDENTIAL					COMMERCIAL				
					Use Per	Heating Degree Days Months of Consumption				Use Per	Heating Degree Days Months of Consumption	
	Year	Month	Customers	Usage	Customer	Concurrent	Trailing	Customers	Usage	Customer	Concurrent	Trailing
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
						0					0	
1	2006	October	1,389,027	21,776,517	15.68	63	0	120,141	24,628,683	205.00	63	0
2	2006	November	1,398,756	47,127,494	33.69	243	63	121,788	34,345,597	282.01	243	63
3	2006	December	1,409,336	112,445,850	79.79	466	243	122,492	59,490,989	485.67	466	243
4	2007	January	1,410,015	167,159,334	118.55	699	466	121,909	81,780,493	670.83	699	466
5	2007	February	1,425,365	182,488,728	128.03	438	699	124,527	90,906,236	730.01	438	699
6	2007	March	1,420,975	87,912,702	61.87	109	438	122,605	53,107,382	433.16	109	438
7	2007	April	1,425,423	47,897,446	33.60	141	109	122,672	36,770,431	299.75	141	109
8	2007	May	1,420,073	33,422,773	23.54	0	141	122,309	31,239,540	255.41	0	141
9	2007	June	1,401,451	32,846,104	23.44	0	0	120,949	30,677,094	253.64	0	0
10	2007	July	1,393,083	10,548,619	7.57	0	0	118,291	19,597,511	165.67	0	0
11	2007	August	1,408,164	19,217,921	13.65	0	0	120,924	23,783,541	196.68	0	0
12	2007	September	1,398,274	17,654,030	12.63	0	0	119,660	21,573,768	180.29	0	0
13	2007	October	1,401,765	22,947,073	16.37	35	0	113,980	26,377,936	231.43	35	0
14	2007	November	1,404,094	40,596,837	28.91	188	35	123,401	31,513,182	255.37	188	35
15	2007	December	1,420,161	110,713,378	77.96	474	188	121,193	58,384,305	481.75	474	188
16	2008	January	1,426,170	175,938,235	123.36	569	474	122,988	86,208,840	700.95	569	474
17	2008	February	1,420,858	148,837,018	104.75	331	569	121,522	77,891,743	640.97	331	569
18	2008	March	1,430,838	104,471,566	73.01	182	331	122,529	60,006,176	489.73	182	331
19	2008	April	1,428,682	51,129,521	35.79	59	182	120,060	40,122,165	334.18	59	182
20	2008	May	1,432,532	30,823,069	21.52	3	59	120,311	30,899,203	256.83	3	59
21	2008	June	1,422,398	22,073,243	15.52	0	3	119,077	25,245,994	212.01	0	3
22	2008	July	1,413,466	20,285,611	14.35	0	0	122,450	24,869,097	203.10	0	0
23	2008	August	1,416,922	18,004,297	12.71	0	0	118,867	21,095,281	177.47	0	0
24	2008	September	1,414,543	17,418,370	12.31	0	0	117,022	21,325,665	182.24	0	0
25	2008	October	1,427,079	21,688,772	15.20	38	0	125,038	25,481,558	203.79	38	0
26	2008	November	1,425,024	42,029,249	29.49	197	38	121,533	32,754,568	269.51	197	38
27	2008	December	1,426,919	128,787,878	90.26	499	197	120,512	64,631,853	536.31	499	197
28	2009	January	1,431,347	160,214,359	111.93	526	499	121,638	79,373,331	652.54	526	499
29	2009	February	1,438,843	125,674,322	87.34	273	526	122,577	66,227,866	540.30	273	526
30	2009	March	1,439,589	87,915,466	61.07	239	273	122,181	51,777,751	423.78	239	273
31	2009	April	1,438,676	61,097,985	42.47	95	239	120,936	40,646,897	336.10	95	239
32	2009	May	1,430,892	30,761,441	21.50	3	95	119,300	31,162,154	261.21	3	95
33	2009	June	1,436,181	21,814,522	15.19	0	3	124,300	23,285,082	187.33	0	3
34	2009	July	1,428,170	20,269,034	14.19	0	0	119,900	23,519,545	196.16	-	-
35	2009	August	1,424,665	18,873,314	13.25	0	0	119,195	22,884,775	191.99	-	-
36	2009	September	1,417,869	17,017,155	12.00	0	0	116,480	20,856,209	179.05	-	-
37	2009	October	1,436,698	25,891,675	18.02	115	0	122,197	25,943,948	212.31	115	-
38	2009	November	1,428,768	45,057,435	31.54	176	65	118,174	33,899,223	286.86	176	65
39	2009	December	1,434,468	138,665,043	96.67	681	194	121,561	67,501,017	555.29	681	194
40	2010	January	1,440,584	213,584,946	148.26	634	521	122,833	101,928,770	829.82	634	521
41	2010	February	1,445,292	180,691,815	125.02	645	304	121,970	87,343,833	716.11	645	304
42	2010	March	1,451,337	152,305,491	104.94	288	437	123,591	78,502,543	635.18	288	437
43	2010	April	1,442,202	63,941,278	44.34	41	170	119,890	44,032,482	367.27	41	170
44	2010	May	1,445,487	28,437,677	19.67	3	6	119,333	29,056,861	243.49	3	6
45	2010	June	1,439,198	21,014,135	14.60	0	0	124,781	24,292,430	194.68	-	-

46	2010	July	1,432,429	20,122,242	14.05	0	0	118,425	23,096,012	195.03	-	-
47	2010	August	1,433,054	18,145,943	12.66	0	0	120,976	22,228,171	183.74	-	-
48	2010	September	1,429,287	17,217,885	12.05	1	0	116,240	21,518,771	185.12	1	-
49	2010	October	1,429,686	19,422,704	13.59	25	1	115,516	23,983,132	207.62	25	1
50	2010	November	1,436,095	41,503,216	28.90	233	25	124,322	32,526,535	261.63	233	25
51	2010	December	1,441,512	111,445,712	77.31	483	233	123,787	56,971,687	460.24	483	233
52	2011	January	1,444,739	175,019,820	121.14	681	483	123,331	83,988,636	681.00	681	483
53	2011	February	1,446,429	201,217,690	139.11	455	681	123,092	98,393,653	799.35	455	681
54	2011	March	1,446,059	78,190,618	54.07	181	455	122,363	50,929,544	416.22	181	455
55	2011	April	1,448,551	42,340,155	29.23	23	181	119,382	34,874,025	292.12	23	181
56	2011	May	1,449,184	29,814,299	20.57	38	23	123,556	28,802,527	233.11	38	23
57	2011	June	1,437,603	22,150,898	15.41	0	0	121,008	25,464,878	210.44	-	-
58	2011	July	1,431,642	18,857,733	13.17	0	0	119,013	25,602,205	215.12	-	-
59	2011	August	1,425,378	16,159,072	11.34	0	0	120,502	18,886,790	156.73	-	-
60	2011	September	1,449,673	16,455,960	11.35	0	0	123,993	21,899,472	176.62	-	-

61 Dependent Variable: RUPC
62 Method: Least Squares
63 Date: 01/23/12 Time: 16:02
64 Sample(adjusted): 2006:11 2011:09
65 Included observations: 59 after adjusting endpoints
66 Convergence achieved after 7 iterations

67 Variable	Coefficient	Std. Error	t-Statistic	Prob.
68 C	11.71885	1.65730451	7.071030034	2.89E-09
69 HDD	0.0978099	0.00670794	14.58121455	1.52E-20
70 HDDLAG	0.1083246	0.00724032	14.96130379	4.88E-21
71 AR(1)	0.3033873	0.13151761	2.306818973	0.02485646

72 R-squared	0.9731733	Mean dependent var	46.8444068
73 Adjusted R-squared	0.97171	S.D. dependent var	41.6364413
74 S.E. of regression	7.0030945	Akaike info criterion	6.79597027
75 Sum squared resid	2697.3833	Schwarz criterion	6.93682027
76 Log likelihood	-196.4811	F-statistic	665.065088
77 Durbin-Watson stat	2.1462046	Prob(F-statistic)	0

78 Inverted AR Roots 0.3

Dependent Variable: CUPC
Method: Least Squares
Date: 01/23/12 Time: 16:06
Sample(adjusted): 2006:11 2011:09
Included observations: 59 after adjusting endpoints
Convergence achieved after 7 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	190.649421	9.143240936	20.8514051	8.70E-28
HDD	0.39535669	0.034763212	11.3728469	4.56E-16
HDDLAG	0.56035151	0.037554442	14.9210448	5.50E-21
AR(1)	0.36239705	0.128836709	2.81284003	0.00679594

R-squared	0.96736893	Mean dependent var	352.751186
Adjusted R-squared	0.96558906	S.D. dependent var	193.45782
S.E. of regression	35.8867879	Akaike info criterion	10.0640044
Sum squared resid	70832.3851	Schwarz criterion	10.2048544
Log likelihood	-292.888131	F-statistic	543.503416
Durbin-Watson stat	2.17900091	Prob(F-statistic)	0

Inverted AR Roots 0.36

ATMOS ENERGY CORP. -- MID-TEX DIVISION
METER INVESTMENT ANALYSIS
TYE 9/30/11

	Meter Class	Cost per Meter (a)	Number of Meters (c) Residential	Commercial	Industrial & Transport	Replacement Cost of Meters Residential	Commercial	Industrial & Transport
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	1	$ 158.00	1,418,075	64708	1	$ 224,055,850	$ 10,223,864	$ 158
2	2	$ 275.00	47,777	19963	2	13,138,675	5,489,825	550
3	3	$ 744.00	17,680	19263	7	13,153,920	14,331,672	5,208
4	4	$ 731.00	1,775	20130	33	1,297,525	14,715,030	24,123
5	5	$ 4,190.00	35	2634	124	146,650	11,036,460	519,560
6	6	$ 4,190.00	33	2007	133	138,270	8,409,330	557,270
7	7	$ 4,190.00	6	168	11	25,140	703,920	46,090
8	8	$ 4,190.00	13	1108	237	54,470	4,642,520	993,030
9	9	$ 4,190.00	30	3349	653	125,700	14,032,310	2,736,070
10	Non-Classified Residential (b)	$ 169.74	19			3,225		
11	Non-Classified Commercial (b)	$ 626.90		22			13,792	
12	Non-Classified Ind. & Transport (b)	$ 4,065.00			586			2,382,087
13	**Total**		1,485,443	133,352	1,787	**$ 252,139,425**	**$ 83,598,723**	**$ 7,264,146**

(a) GUD No. 9670
(b) Average cost of Classified Meters
(c) Classified Meters from GUD No. 9670; Total Meters from Meter Count and GUD No. 9670

ATMOS ENERGY CORP. -- MID-TEX DIVISION
O&M EXPENSE ALLOCATION
TYE 9/30/11

	Acct. No.	Description	Amount	O&M EXPENSE ALLOCATION Residential	Commercial	Industrial & Transport
	(a)	(b)	(c)	(d)	(e)	(f)
1	Mid-Tex:					
2	841	Natural gas storage - Operation labor and expenses	$ 541	$ 249	$ 164	$ 128
3	870	Operation Supervision and Engineering	3,782,005	2,867,172	788,577	126,256
4	871	Distribution Load Dispatching	1,079,099	496,778	326,131	256,190
5	872	Compressor Station Labor and Expenses	0	-	-	-
6	874	Mains and Services Expenses	30,105,537	23,155,430	6,099,133	850,975
7	875	Measuring and Regulating Station Expenses - General	58,239	42,368	13,778	2,093
8	876	Measuring and Regulating Station Expenses - Industrial	3,183	-	-	3,183
9	877	Measuring and Regulating Station Exp. - City Gate Chk. Sta.	3,596	2,616	851	129
10	878	Meter and House Regulator Expenses	3,286,855	2,416,152	801,094	69,609
11	879	Customer Installations Expenses	707,891	648,861	58,250	781
12	880	Other Expenses	5,516,069	4,181,781	1,150,143	184,145
13	881	Rents	94,514	71,652	19,707	3,155
14	885	Maintenance Supervision and Engineering	5,921	4,488	1,234	198
15	886	Maintenance of Structures and Improvements	24,022	17,475	5,683	863
16	887	Maintenance of Mains	1,276,616	928,727	302,009	45,879
17	888	Maintenance of compressor station equipment	2,647	1,218	800	628
18	889	Maint. of Measuring and Regulating Station Equip. - General	2,279,612	1,658,398	539,288	81,925
19	890	Maint. of Measuring and Regulating Station Equip. - Industrial	2,143	-	-	2,143
20	891	Maint. of Measuring and Regulating Station Equip. - City Gate	1,379	1,003	326	50
21	892	Maintenance of Services	470,357	431,134	38,704	519
22	893	Maintenance of Meters and House Regulators	242,812	178,490	59,180	5,142
23	894	Maintenance of Other Equipment	805,036	610,305	167,856	26,875
24	901	Supervision	184	169	15	0
25	902	Meter Reading Expense	7,862,520	7,206,871	646,979	8,670
26	903	Customer Records and Collection Expenses	15,078,152	11,554,864	3,106,015	417,274
27	904	Uncollectible Accounts	3,589,132	2,916,654	531,299	141,178
28	905	Miscellaneous Customer Accounts Expenses	100	92	8	0
29	907	Supervision	-	-	-	-
30	908	Customer Assistance Expenses	88,839	81,431	7,310	98
31	909	Informational and Instructional Advertising Expenses	4,920	4,509	405	5
32	910	Miscellaneous Customer Service and Informational Expenses	2,561,828	2,348,199	210,804	2,825
33	911	Supervision	3,540	3,245	291	4
34	912	Demonstrating and Selling Expenses	57,677	52,868	4,746	64
35	913	Advertising Expenses	1,985,790	1,820,196	163,404	2,190
36	916	Miscellaneous Sales Expenses	20	19	2	0
37	920	Administrative and General Salaries	4,362,208	3,445,284	799,663	117,261
38	921	Office Supplies and Expenses	219,286	173,193	40,199	5,895
39	922	Administrative Expenses Transferred - Customer Support	20,738,706	15,892,725	4,272,057	573,924
40	922	Administrative Expenses Transferred - General	23,298,070	18,400,881	4,270,909	626,280
41	923	Outside Services Employed	1,150,183	908,418	210,847	30,918
42	924	Property Insurance	739,904	567,011	152,416	20,476
43	925	Injuries and Damages	1,306,752	1,032,076	239,549	35,127
44	926	Employee Pensions and Benefits	16,202,802	12,797,018	2,970,233	435,551
45	928	Regulatory Commission Expenses	-	-	-	-
46	929	Duplicate Charges - Credit	-	-	-	-
47	930.1	General Advertising Expenses	5,203	4,769	428	6
48	930.2	Miscellaneous General Expense	298,948	236,110	54,802	8,036
49	931	Rents	836,378	660,573	153,321	22,483
50	932	Maintenance of General Plant	662	523	121	18
51	Total Operation and Maintenance Expenses		$ 150,139,876	$ 117,821,997	$ 28,208,729	$ 4,109,151

ATMOS ENERGY CORP. -- MID-TEX DIVISION
O&M EXPENSE ALLOCATION

			Total		Residential		Commercial		Industrial & Transport
(a)	Composite of Accts. 871-879 & 886-893								
	871 Distribution Load Dispatching	$	1,079,099	$	496,778	$	326,131	$	256,190
	872 Compressor Station Labor and Expenses		-		-		-		-
	874 Mains and Services Expenses		30,105,537		23,155,430		6,099,133		850,975
	875 Measuring and Regulating Station Expenses - General		58,239		42,368		13,778		2,093
	876 Measuring and Regulating Station Expenses - Industrial		3,183		-		-		3,183
	877 Measuring and Regulating Station Exp. - City Gate Chk. Sta.		3,596		2,616		851		129
	878 Meter and House Regulator Expenses		3,286,855		2,416,152		801,094		69,609
	879 Customer Installations Expenses		707,891		648,861		58,250		781
	886 Maintenance of Structures and Improvements		24,022		17,475		5,683		863
	887 Maintenance of Mains		1,276,616		928,727		302,009		45,879
	888 Maintenance of compressor station equipment		2,647		1,218		800		628
	889 Maint. of Measuring and Regulating Station Equip. - General		2,279,612		1,658,398		539,288		81,925
	890 Maint. of Measuring and Regulating Station Equip. - Industrial		2,143		-		-		2,143
	891 Maint. of Measuring and Regulating Station Equip. - City Gate		1,379		1,003		326		50
	892 Maintenance of Services		470,357		431,134		38,704		519
	893 Maintenance of Meters and House Regulators		242,812		178,490		59,180		5,142
	Total	$	39,543,988	$	29,978,652	$	8,245,225	$	1,320,110
	Allocation Factor		**100.00%**		**75.81%**		**20.85%**		**3.34%**
(b)	Throughput								
	Total		166,399,699		76,604,326		50,290,241		39,505,132
	Allocation Factor		**100.00%**		**46.04%**		**30.22%**		**23.74%**
(c)	Composite of Accts. 376 & 380								
	376 Mains	$	1,094,203,508	$	796,023,804	$	258,855,836	$	39,323,868
	380 Services		309,041,134		283,270,448		25,429,909		340,777
	Total	$	1,403,244,642	$	1,079,294,252	$	284,285,746	$	39,664,645
	Allocation Factor		**100.00%**		**76.91%**		**20.26%**		**2.83%**
(d)	Composite of Accts. 374-379								
	374 Land & Land Rights	$	2,323,486	$	1,690,316	$	549,667	$	83,502
	375 Structures & Improvements		140,099		101,921		33,143		5,035
	376 Mains		1,094,203,508		796,023,804		258,855,836		39,323,868
	378 M&R Station Equipment - General		20,850,219		15,168,358		4,932,538		749,322
	379 M&R Station Equipment - City Gate		2,532,453		1,842,338		599,103		91,012
	Total	$	1,120,049,764	$	814,826,736	$	264,970,288	$	40,252,740
	Allocation Factor		**100.00%**		**72.75%**		**23.66%**		**3.59%**
(e)	Direct to Ind. & Trans.								
	Allocation Factor		**100.00%**		**0.00%**		**0.00%**		**100.00%**
(f)	Composite of Accts. 381-383								
	381 Meters	$	92,254,655	$	67,815,977	$	22,484,897	$	1,953,781
	382 Meter Installations		79,966,185		58,782,779		19,489,872		1,693,534
	383 House Regulators		35,003,261		25,730,738		8,531,220		741,303
	Total	$	207,224,101	$	152,329,493	$	50,505,989	$	4,388,618
	Allocation Factor		**100.00%**		**73.51%**		**24.37%**		**2.12%**
(g)	No. of Customer Locations								
	No. of Customer Locations		1,620,582		1,485,443		133,352		1,787
	Allocation Factor		**100.00%**		**91.66%**		**8.23%**		**0.11%**

ATMOS ENERGY CORP. -- MID-TEX DIVISION
O&M EXPENSE ALLOCATION

		Total	Residential	Commercial	Industrial & Transport
(h)	Account 380				
	380 Services	$ 309,041,134	$ 283,270,448	$ 25,429,909	$ 340,777
	Allocation Factor	**100.00%**	**91.66%**	**8.23%**	**0.11%**
(i)	Plant Weighted Customers				
	Net Plant Investment	$ 1,793,097,349	$ 1,374,107,069	$ 369,367,977	$ 49,622,303
	Allocation Factor	**100.00%**	**76.63%**	**20.60%**	**2.77%**
(j)	GUD 9400 Allocation Factors				
	Allocation Factor	**100.00%**	**81.26%**	**14.80%**	**3.93%**
(k)	Composite of Accts. 870-902, 905-916, 924 & 928-930.1				
	Accts. 870-902	$ 57,610,236	$ 44,921,090	$ 11,019,737	$ 1,669,409
	Accts. 905-916	4,702,713	4,310,558	386,970	5,186
	Acct. 924	739,904	567,011	152,416	20,476
	Accts. 928-930.1	5,203	4,769	428	6
	Total	$ 63,058,056	$ 49,803,429	$ 11,559,551	$ 1,695,076
	Allocation Factor	**100.00%**	**78.98%**	**18.33%**	**2.69%**
(l)	Total Plant				
	Total Plant	$ 1,793,097,349	$ 1,374,107,069	$ 369,367,977	$ 49,622,303
	Allocation Factor	**100.00%**	**76.63%**	**20.60%**	**2.77%**

ATMOS ENERGY CORP. – MID-TEX DIVISION
DEPRECIATION EXPENSE ALLOCATION
TYE 9/30/11

Class Cost of Service Study - 8
Page 1 of 1

	Acct. No.	Description	TOTAL NET PLANT	ALLOCATED NET PLANT (a) Residential	Commercial	Industrial & Transport	ALLOCATION FACTOR (b) Residential	Commercial	Industrial & Transport	DEPRECIATION EXPENSE (c)	DEPRECIATION ALLOCATION Residential	Commercial	Industrial & Transport
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**Mid-Tex:**												
2	**Distribution Plant**												
3	374	Land	$ 772,350	$ 561,878	$ 182,715	$ 27,757	72.75%	23.66%	3.59%	$ -	$ -	$ -	$ -
4	374	Land Rights	1,551,135	1,128,438	366,952	55,745	72.75%	23.66%	3.59%	31,383	22,831	7,424	1,128
5	375	Structures & Improvements	140,099	101,921	33,143	5,035	72.75%	23.66%	3.59%	25,113	18,269	5,941	903
6	376	Mains	1,094,203,508	796,023,804	258,855,836	39,323,868	72.75%	23.66%	3.59%	39,700,225	28,881,578	9,391,886	1,426,761
7	378	M&R Station Equipment - General	20,850,219	15,168,358	4,932,538	749,322	72.75%	23.66%	3.59%	1,206,716	877,876	285,473	43,367
8	379	M&R Station Equipment - City Gate	2,532,453	1,842,338	599,103	91,012	72.75%	23.66%	3.59%	103,661	75,413	24,523	3,725
9	380	Services	309,041,134	283,270,448	25,429,909	340,777	91.66%	8.23%	0.11%	27,834,371	25,513,286	2,290,393	30,693
10	381	Meters	92,254,655	67,815,977	22,484,897	1,953,781	73.51%	24.37%	2.12%	5,349,320	3,932,261	1,303,771	113,289
11	382	Meter Installations	79,966,185	58,782,779	19,489,872	1,693,534	73.51%	24.37%	2.12%	4,166,943	3,063,101	1,015,594	88,248
12	383	House Regulators	35,003,261	25,730,738	8,531,220	741,303	73.51%	24.37%	2.12%	1,657,343	1,218,305	403,938	35,099
13	385	Industrial M&R Station Equipment	1,106,639	-	-	1,106,639	0.00%	0.00%	100.00%	35,857	-	-	35,857
14		Total Distribution Plant	$ 1,637,421,637	$ 1,250,426,678	$ 340,906,186	$ 46,088,774				$ 80,110,931	$ 63,602,919	$ 14,728,943	$ 1,779,069
15	**General Plant**												
16	302	Franchises & Consents	$ 11,665	$ 8,940	$ 2,403	$ 323	76.63%	20.60%	2.77%	$ -	$ -	$ -	$ -
17	303	Computer Software	(88,372)	(67,722)	(18,204)	(2,446)	76.63%	20.60%	2.77%	-	-	-	-
18	389	Land	3,736,957	2,863,748	769,792	103,417	76.63%	20.60%	2.77%	-	-	-	-
19	390	Structures & Improvements	15,363,830	11,773,788	3,164,863	425,180	76.63%	20.60%	2.77%	758,683	581,403	156,284	20,996
20	391	Office Furniture & Equipment	4,064,527	3,114,775	837,270	112,482	76.63%	20.60%	2.77%	258,387	198,010	53,226	7,151
21	392	Transportation Equipment	4,825,988	3,698,307	994,126	133,555	76.63%	20.60%	2.77%	296,944	227,558	61,169	8,218
22	393	Stores Equipment	129,289	99,079	26,633	3,578	76.63%	20.60%	2.77%	1,563	1,198	322	43
23	394	Tools, Shop, and Garage Equipment	10,837,058	8,304,779	2,232,373	299,905	76.63%	20.60%	2.77%	159,005	121,851	32,754	4,400
24	395	Laboratory Equipment	335,825	257,353	69,178	9,294	76.63%	20.60%	2.77%	8,893	6,815	1,832	246
25	396	Power Oper. Tool & Work Equipment	3,786,008	2,901,337	779,896	104,774	76.63%	20.60%	2.77%	164,138	125,784	33,812	4,542
26	397	Radio Communication Equipment	6,661,088	5,104,602	1,372,147	184,339	76.63%	20.60%	2.77%	544,801	417,498	112,226	15,077
27	398	Miscellaneous Equipment	3,521,492	2,698,630	725,408	97,454	76.63%	20.60%	2.77%	380,469	291,566	78,375	10,529
28	399	Non-Mainframe Computer Equipment	10,671,534	8,177,933	2,198,276	295,325	76.63%	20.60%	2.77%	1,627,317	1,247,064	335,218	45,034
29	RWIP	Retirement Work in Progress	36,203,431	27,743,831	7,457,703	1,001,896	76.63%	20.60%	2.77%	-	-	-	-
30		Total General Plant	$ 100,060,320	$ 76,679,380	$ 20,611,864	$ 2,769,076				$ 4,200,202	$ 3,218,747	$ 865,218	$ 116,237
31		Accrual for Reserve Deficiency	$ 100,060,320	$ 76,679,380	$ 20,611,864	$ 2,769,076	76.63%	20.60%	2.77%	$ 70,367	53,924	14,495	1,947
32	**Shared Services Unit:**												
33		**Customer Support**	$ 29,153,602	$ 26,722,507	$ 2,398,948	$ 32,147	91.66%	8.23%	0.11%	$ 4,731,235	$ 4,336,701	$ 389,317	$ 5,217
34		**General Plant**	26,461,789	20,278,504	5,450,980	732,305	76.63%	20.60%	2.77%	3,858,977	2,957,256	794,928	106,794
35		Total Shared Services Plant	$ 55,615,391	$ 47,001,011	$ 7,849,927	$ 764,453				$ 8,590,212	$ 7,293,957	$ 1,184,244	$ 112,011
36		**TOTAL PLANT**	$ 1,793,097,349	$ 1,374,107,069	$ 369,367,977	$ 49,622,303							
37		**TOTAL DEPRECIATION EXPENSE**								$ 92,971,711	$ 74,169,547	$ 16,792,900	$ 2,009,264

(a) Class Cost of Service Study - 3, Plant Allocation
(b) Class Allocated Net Plant as a percent of Total Net Plant
(c) Distribution Plant Depreciation Expense spread to accounts based on Gross Plant from Class Cost of Service Study - 3, Plant Allocation.

ATMOS ENERGY CORP. -- MID-TEX DIVISION
TAXES OTHER THAN INCOME ALLOCATION
TYE 9/30/11

	Description	Amount	TAXES OTHER THAN INCOME ALLOCATION Residential	Commercial	Industrial & Transport	Reference	Description
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Non Revenue-Related Taxes:**						
2	Ad Valorem Tax	$ 21,129,326	$ 16,192,069	$ 4,352,522	$ 584,734	(a)	Total Plant
3	Payroll Tax	$ 2,722,791	2,136,706	511,566	74,520	(b)	O&M Expenses
4	DOT Pipeline User Fee	$ 75,921	59,579	14,264	2,078	(b)	O&M Expenses
5	Non Revenue - Related Taxes Allocated from SSU	$ 2,148,830	1,686,290	403,729	58,811	(b)	O&M Expenses
6	**Total Non Revenue-Related**	**$ 26,076,868**	**$ 20,074,644**	**$ 5,282,081**	**$ 720,143**		
7	**Revenue-Related Taxes:**						
8	State Gross Receipts Taxes	$ 20,249,735					Collected through Riders FF & Tax
9	Local Franchise Fees	$ 60,167,610					Collected through Riders FF & Tax
10	Railroad Commission Fees	$ 62,540					Collected through Riders FF & Tax
11	**Total Revenue-Related**	**$ 80,479,885**	**$ -**	**$ -**	**$ -**		
12	**Taxes Other than Income**	**$ 106,556,753**	**$ 20,074,644**	**$ 5,282,081**	**$ 720,143**		

		Total	Residential	Commercial	Industrial & Transport	Reference	
(a)	Total Plant						
	Total Plant	$ 1,793,097,349	$ 1,374,107,069	$ 369,367,977	$ 49,622,303	CCS-3	Plant Allocation
	Allocation Factor	**100.00%**	**76.63%**	**20.60%**	**2.77%**		
(b)	O&M Expenses						
	O&M Expenses	$ 150,139,876	$ 117,821,997	$ 28,208,729	$ 4,109,151	CCS-7	O&M Expense Allocation
	Allocation Factor	**100.00%**	**78.47%**	**18.79%**	**2.74%**		

Atmos Energy Corporation
Mid-Tex Division
Summary of Pension and Other Postemployment Benefits Expense Calculation

Line No.	Description	GUD 9869 FAS 87	GUD 9869 FAS 106	GUD 9869 SERP	GUD 9869 Total	GUD 9869 with Towers Watson 2012 Estimates FAS 87	GUD 9869 with Towers Watson 2012 Estimates FAS 106	GUD 9869 with Towers Watson 2012 Estimates SERP	GUD 9869 with Towers Watson 2012 Estimates Total	Total Deferral	Deferral FAS 87	Deferral FAS 106	Deferral SERP
	(a)	(b)	(c)	(d)	(e) = (b + c + d)	(f)	(g)	(h)	(i) = (f + g + h)	(j) = (i - e)	(k) = (f - b)	(l) = (g - c)	(m) = (h - d)
1	Mid-Tex Expense	$2,874,946	#########	$171,212	$ 7,114,721	$ 5,941,774	$ 4,918,042	#######	$ 11,003,206	$ 3,888,485	$ 3,066,828	$ 849,479	$ (27,822)
2	Mid-Tex Capital	2,912,514	4,225,387	-	7,137,901	5,941,186	5,127,874	-	11,069,060	3,931,159	3,028,671	902,487	-
3													
4	Total (Ln. 2 plus Ln. 3)	$5,787,460	#########	$171,212	$ 14,252,622	$11,882,960	$10,045,916	#######	$ 22,072,266	$ 7,819,644	$ 6,095,500	$ 1,751,966	$ (27,822)
5													
6	Regulatory Asset (Expense):												
7													
8	Asset January through September 2012 (End of the Fiscal Year) (Col (j) Ln 1 x 9/12)									$2,916,363.91	$2,300,121.15	$ 637,109.25	$ (20,866.50)
9	Asset January through March 2012 (Col (j) Ln 8 x 1/3) (1)									$ 972,121	$ 766,707	$ 212,370	$ (6,956)
10													
11	Regulatory Asset (Capital):												
12													
13	Asset January through September 2012 (End of the Fiscal Year) (Col (j) Ln 2 x 9/12)									$ 2,948,369	$ 2,271,504	$ 676,865	$ -
14	Asset January through March 2012 (Col (j) Ln 13 x 1/3) (1)									$ 982,790	$ 757,168	$ 225,622	$ -
15													
16													
17	Total Regulatory Asset through March 2012 (Ln 9 plus Ln 14)									$ 1,954,911	$ 1,523,875	$ 437,992	$ (6,956)
18													
19	Note:												
20	1. January through March (three months) is 1/3 of the remaining nine months of the fiscal year.												

ATMOS ENERGY CORP., MID-TEX DIVISION
PENSIONS AND RETIREE MEDICAL BENEFITS ADJUSTMENT
TEST YEAR ENDING JUNE 30, 2008
GUD 9869

Line No.	Description	Shared Services: Pension Account Plan ("PAP")	Shared Services: Post-Retirement Medical Plan ("FAS 106")	Mid-Tex Direct: Pension Account Plan ("PAP")	Mid-Tex Direct: Post-Retirement Medical Plan ("FAS 106")	Mid-Tex Direct: Supplemental Executive Benefit Plan (SERP)
	(a)	(b)	(c)	(d)	(e)	(f)
1	Fiscal Year 2009 Towers Perrin Report	$ 2,825,263	$ 3,660,066	$ 4,711,600	$ 6,900,197	$ 171,212
2	Test Year Amounts	2,582,475	2,758,179	3,959,453	4,919,144	192,563
3	Test Year Change for Actuarially Determined Benefit Costs (Ln. 1 minus Ln.2)	$ 242,788	$ 901,887	$ 752,147	$ 1,981,053	$ (21,351)
4	Allocation to Mid-Tex	38.08%	38.08%	100.00%	100.00%	100.00%
5	Test Year Change for Actuarially Determined Benefit Costs Allocated to Mid-Tex (Ln. 3 times Ln. 4)	$ 92,454	$ 343,439	$ 752,147	$ 1,981,053	$ (21,351)
6	O&M Expense Factor	77.99%	77.99%	43.21%	43.21%	100.00%
7	Test Year Adjustment for Actuarially Determined Benefit Costs (Ln. 5 times Ln. 6)	$ 72,105	$ 267,848	$ 325,003	$ 856,013	$ (21,351)
8						
9	Expense on FY 2009 Towers Perrin (Ln. 1 times Ln. 4 times Ln. 6)	$ 839,063	$ 1,086,988	$ 2,035,882	$ 2,981,575	$ 171,212
10						
11	Capital Percentage (1 minus Ln. 6)	22.01%	22.01%	56.79%	56.79%	0.00%
12						
13	Capital (Ln. 1 times Ln. 4 times Ln. 11)	$ 236,797	$ 306,765	$ 2,675,718	$ 3,918,622	$ -
14						
15	Total (Ln. 9 plus Ln. 13)	$ 1,075,860	$ 1,393,753	$ 4,711,600	$ 6,900,197	$ 171,212

ATMOS ENERGY CORP., MID-TEX DIVISION
PENSIONS AND RETIREE MEDICAL BENEFITS ADJUSTMENT
2012 TOWERS WATSON ESTIMATES WITH GUD 9869 ASSUMPTIONS

		Shared Services				Mid-Tex Direct					
Line No.	Description		Pension Account Plan ("PAP")		Post-Retirement Medical Plan ("FAS 106")		Pension Account Plan ("PAP")		Post-Retirement Medical Plan ("FAS 106")		Supplemental Executive Benefit Plan (SERP)
	(a)		(b)		(c)		(d)		(e)		(f)
1	Fiscal Year 2012 Towers Watson Report	$	6,094,332	$	4,358,139	$	9,562,238	$	8,386,337	$	143,390
2	Test Year Amounts		-		-		-		-		-
3	Test Year Change for Actuarially Determined Benefit Costs (Ln. 1 minus Ln.2)	$	6,094,332	$	4,358,139	$	9,562,238	$	8,386,337	$	143,390
4	Allocation to Mid-Tex		38.08%		38.08%		100.00%		100.00%		100.00%
5	Test Year Change for Actuarially Determined Benefit Costs Allocated to Mid-Tex (Ln. 3 times Ln. 4)	$	2,320,722	$	1,659,579	$	9,562,238	$	8,386,337	$	143,390
6	O&M Expense Factor		77.99%		77.99%		43.21%		43.21%		100.00%
7	Test Year Adjustment for Actuarially Determined Benefit Costs (Ln. 5 times Ln. 6)	$	1,809,931	$	1,294,306	$	4,131,843	$	3,623,736	$	143,390
8											
9	Expense on FY 2012 Towers Perrin (Ln. 1 times Ln. 4 times Ln. 6)	$	1,809,931	$	1,294,306	$	4,131,843	$	3,623,736	$	143,390
10											
11	Capital Percentage (1 minus Ln. 6)		22.01%		22.01%		56.79%		56.79%		0.00%
12											
13	Capital (Ln. 1 times Ln. 4 times Ln. 11)	$	510,791	$	365,273	$	5,430,395	$	4,762,601	$	-
14											
15	Total (Ln. 9 plus Ln. 13)	$	2,320,722	$	1,659,579	$	9,562,238	$	8,386,337	$	143,390

BEFORE THE TENNESSEE REGULATORY AUTHORITY

AT NASHVILLE, TENNESSEE

December 4, 2012

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY CORPORATION FOR A GENERAL RATE INCREASE	))	DOCKET NO. 12-00064
	)	

ORDER APPROVING SETTLEMENT AGREEMENT

This matter came before Director Sara Kyle, Director Herbert H. Hilliard and Director James M. Allison of the Tennessee Regulatory Authority (the "Authority" or "TRA"), the voting panel assigned to this docket, at a Hearing held on November 7, 2012, for consideration of the *Stipulation and Settlement Agreement* filed on October 30, 2012.

BACKGROUND

Atmos Energy Corporation ("Atmos" or the "Company") filed a *Petition for Rate Change* on June 22, 2012, requesting an increase in its annual revenues of approximately $10.8 million.[1] According to Atmos, the requested rate increase would provide a projected rate of return of 8.75% on a projected total rate base of $208,661,037 and a rate of return on projected common equity of 11.0%.[2] The Company also submitted pre-filed testimony from several witnesses in support of its *Petition*.

The Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate") filed a Petition to Intervene on July 11, 2012, which was granted by the

[1] *Petition for Rate Change*, p. 3 (June 22, 2012).
[2] *Id.*

Hearing Officer on August 20, 2012.[3] The Consumer Advocate submitted pre-filed testimony on October 5, 2012.

On October 30, 2012, Atmos and the Consumer Advocate (collectively, the "Parties") submitted the proposed *Stipulation and Settlement Agreement*, as described below.

STIPULATION AND SETTLEMENT AGREEMENT

The proposed *Stipulation and Settlement Agreement*, which is fully set forth in Exhibit A to this Order, provides for a revenue increase of $7.1 million annually.[4] For purposes of settling the docket, the Parties agree to a required net operating income of $16,677,604 and a rate base of $201,359,443.[5] In addition, the Parties agree to an overall return of 8.28%, which includes a return on equity of 10.1%.[6] The Parties also agree that the rates reflected in the *Stipulation and Settlement Agreement* are fair and reasonable and appropriate for the purpose of resolving this proceeding.[7]

The Parties further agree that the Company shall file quarterly updates on its bare steel pipe replacement spending.[8] In addition, the *Stipulation and Settlement Agreement* provides for a mechanism to be put in place to true-up Atmos' pension funding quarterly, resulting in the establishment of a regulatory asset to be included in the rate base calculation of the Company until the TRA orders new treatment.[9] The Parties also agree to use the depreciation rates contained in the testimony of Company witness Thomas Petersen, which would become effective December 1, 2012.[10]

---

[3] The Hearing Officer granted the intervention request orally at a Status Conference held on August 20, 2012, and memorialized the decision in an Order issued on August 27, 2012.
[4] *Stipulation and Settlement Agreement*, p. 3 (October 30, 2012).
[5] *Id.*
[6] *Id.*
[7] *Id.*
[8] *Id.* at 4.
[9] *Id.*
[10] *Id.*

In addition, the Parties agree that the normal heating degree days and Weather Normalization Adjustment ("WNA") factors set forth in Attachments C and E are appropriate and should be effective December 1, 2012, and that the period for the WNA adjustment going forward should consist of the months of October through April of each year.[11]

In Paragraph 11d, the *Stipulation and Settlement Agreement* also provides that the Company's rate case expenses will be amortized over a period of three years, and $20,000 shall be paid to the Consumer Advocate from Atmos' budgeted rate case expenses to offset the accounting witness fees incurred by the Consumer Advocate in this proceeding.[12]

The Parties agree that the revised rate schedules and service regulations as set forth in Attachments D and E to the *Stipulation and Settlement Agreement* are fair and reasonable for the purpose of settlement of this proceeding and that the revised rates will be effective for bills rendered on or after December 1, 2012.[13] The Parties also agree that the revised rates, tariffs, rate schedules and service regulations in the settlement are fair and reasonable to all customer classes and will provide Atmos with a reasonable opportunity to recover the revenue requirement and a reasonable rate of return on investment.[14]

The Parties request the Authority to order that the settlement of any issue pursuant to the *Stipulation and Settlement Agreement* shall not be cited by the Parties or any other entity as binding precedent in any other proceeding before the Authority or any court, state or federal.[15]

The *Stipulation and Settlement Agreement* also provides that if the Authority does not approve the agreement in its entirety, each of the signatories has the right to terminate the agreement within twenty (20) business days or can, by unanimous consent, elect to modify the *Stipulation and Settlement* Agreement to address any modification required by, or issues raised,

---

[11] *Id.* at 5.
[12] *Id.*
[13] *Id.*
[14] *Id.*
[15] *Id.* at 6.

by the Authority. If the agreement terminates, each signatory reserves their rights to fully participate in all relevant proceedings notwithstanding their agreement to the terms of the *Stipulation and Settlement Agreement.*[16]

<u>THE HEARING</u>

The Hearing in this matter was held before the voting panel on November 7, 2012, as noticed by the Authority on October 29, 2012.[17] Participating in the Hearing were the following Parties and their respective counsel:

> <u>Atmos Energy Corporation</u> – **A. Scott Ross, Esq.,** Neal & Harwell, PLC, 2000 One Nashville Place, 150 Fourth Ave. North, Nashville, TN 37219.
>
> <u>Consumer Advocate and Protection Division</u> – **Ryan McGehee, Esq.**, Office of the Attorney General, 425 5th Ave. N, John Sevier Building, P.O. Box 20207, Nashville, TN 37202.

During the Hearing, the *Stipulation and Settlement Agreement* was presented to the panel, and both Parties indicated they were in agreement. Members of the public were given an opportunity to offer comments, but no one sought recognition to do so.

<u>FINDINGS AND CONCLUSIONS</u>

Following the Hearing and presentation of the proposed *Stipulation and Settlement Agreement*, the panel deliberated this matter on November 7, 2012. The panel found that the terms of the agreement were within the "zone of reasonableness" that takes into consideration both the interests of the consumer and the utility,[18] and further promote the public interest by balancing the interests of the utility consumers and the provider. In addition, the panel found that, in accepting the *Stipulation and Settlement Agreement*, the Authority was not adopting any specific means, models or methodologies used to calculate the resulting agreed-upon terms.

---

[16] *Id.* at 7.
[17] On October 30, 2012, Atmos filed its Notice of Compliance as required by TRA Rule 1220-4-1-.05.
[18] *See Tennessee Cable Television Ass'n v. Public Serv. Comm'n*, 844 S.W. 2nd 151, 159 (Tenn. Ct. App. 1992).

However, the panel found that the provision contained in Paragraph 11d of the *Stipulation and Settlement Agreement* that requires Atmos to pay the Consumer Advocate $20,000 to offset the Consumer Advocate's accounting witness fees was not appropriate nor in the public interest.[19] Based upon these findings, the panel voted unanimously to approve the *Stipulation and Settlement Agreement* contingent upon the Parties agreeing to remove the portion of Paragraph 11d relating to witness fees from their agreement. At the Hearing, the Parties agreed to removal of the $20,000 accounting witness fee provision in Paragraph 11d.[20]

IT IS THEREFORE ORDERED THAT:

1. The *Stipulation and Settlement Agreement,* a copy of which is attached to this Order as Exhibit A, and as amended by the deletion of the $20,000 accounting witness fee provision in Paragraph 11d agreed to by the Parties, is approved, adopted and incorporated in this Order as if fully rewritten herein.

2. The settlement of any issue pursuant to the *Stipulation and Settlement Agreement* shall not be cited by the Parties or any other entity as binding precedent in any other proceeding before the Authority or any court, state or federal.

Director Sara Kyle, Director Herbert H. Hilliard and Director James M. Allison concur.

ATTEST:

Earl Taylor

Earl R. Taylor, Executive Director

[19] *See Stipulation and Settlement Agreement*, p. 5, ¶ 11d (October 30, 2012). Director Kyle noted that she had been assigned to *In re: Petition of Atmos Energy Corporation for Approval of a General Rate Increase,* TRA Docket No. 07-00105, which had allowed a similar payment for the Consumer Advocate's expert witness, but drew a distinction between that case and the present docket. In Docket No. 07-00105, the Consumer Advocate hired a depreciation expert to conduct a depreciation study because it did not have the expertise to conduct such a study. In this docket, however, the Consumer Advocate is using the same experts as it normally does. Director Kyle also noted that the settlement in Docket No. 07-00105 made it clear that approval of the payment did not create a precedent and, therefore, the Authority is not bound by its previous decision.

[20] Transcript of Proceedings, pp. 15-16 (November 7, 2012).

EXHIBIT A

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	**Docket No. 12-00064**
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	

STIPULATION AND SETTLEMENT AGREEMENT

For the sole purpose of settling this case, Tennessee Regulatory Authority ("TRA" or "Authority") Docket No. 12-00064, Robert E. Cooper, Jr., the Tennessee Attorney General and Reporter, through the Consumer Advocate and Protection Division ("Consumer Advocate") and Atmos Energy Corporation ("Atmos" or "the Company") respectfully submit this Stipulation and Settlement Agreement. Subject to Authority approval, the Consumer Advocate and Atmos (collectively, the "Parties") agree to the following:

BACKGROUND

1. Atmos is incorporated under the laws of the State of Texas and the Commonwealth of Virginia and is engaged in the business of transporting, distributing and selling natural gas in Bedford, Blount, Carter, Greene, Hamblen, Maury, Moore, Obion, Rutherford, Sullivan and Williamson Counties within the State of Tennessee, with its principal Tennessee office and place of business located at 810 Crescent Centre Drive, Suite 600, Franklin, Tennessee 37067-6226.

2. The Tennessee public utility operations of Atmos are subject to the jurisdiction of the TRA, pursuant to Chapter 4 of Tile 65 of the Tennessee Code Annotated.

3. On June 22, 2012, Atmos filed a petition for adjustment of its rates and approval of a revised tariff. In that filing Atmos claimed a revenue deficiency and sought an increase in its annual revenues of approximately $10.8 million. Atmos last filed for a rate increase in 2008.

4. On July 11, 2012, the Consumer Advocate filed a petition to intervene. By order dated August 27, 2012, intervention was granted.

5. The Parties to this Settlement Agreement have engaged in substantial discovery. The Company also has provided information informally in response to questions from the Consumer Advocate and its witnesses, and has responded to additional discovery requests from TRA Staff. The Consumer Advocate filed direct testimony on October 5, 2012, challenging several aspects of the Company's proposed rate increase. The Parties have undertaken extensive discussions and "give and take" negotiations to resolve all known disputed issues in this case. As a result of the information obtained during discovery and the discussions between the Parties, and for the purpose of avoiding further litigation and resolving this matter upon acceptable terms, the Parties have reached this Settlement Agreement. In furtherance of this Settlement Agreement, the Parties have agreed to the settlement terms set forth below.

SETTLEMENT

6. Based upon the exchange of information and discussions described above, and in order to resolve this case through settlement and avoid the need for further litigation and expenses for all Parties and without waiving any positions asserted in this docket, the Parties have agreed to certain adjustments to the Company's Petition, which are discussed herein.

7. **Attrition Period:** The Parties agree that the appropriate attrition period for use in this proceeding is the 12 months ended November 30, 2013.

8. **Revenue Deficiency:** The adjustments to the Company's filed case collectively reduce the Company's attrition period revenue deficiency from $10.8 million (a proposed increase of 8.97%) to $7.1 million (an increase of 5.9%). Subject to Authority approval, the Parties agree that this revenue deficiency is reasonable and appropriate for the limited purpose of resolving this docket.

9. **Revenue Requirement:** The Parties agree that the Company's attrition period cost of service should include the components set forth on Attachment A hereto, which the Parties agree are fair and reasonable to the Company and its customers for limited purpose of settling this docket, and which include the following:

a. Required Operating Income of $16,677,604;

b. A rate base of $201,359,443;

c. An overall rate of return of 8.28% on rate base;

d. A return on common equity of 10.1%;

e. A capital structure consisting of 1.26% short-term debt, 47.42% long-term debt, and 51.32% equity;

f. A cost of short-term debt of 1.34%;

g. A cost of long term debt of 6.5%;

h. An attrition period revenue deficiency of $7,100,000;

10. **Rates:** The Parties agree that the rates reflected on Attachment B are fair and reasonable and appropriate for limited purpose of resolving this proceeding.

11. The Parties further stipulate and agree:

a. That the Company shall file quarterly updates on its bare steel pipe replacement spending, which shall be filed publicly in this docket and served electronically to the Consumer Advocate;

b. That for the purpose of this proceeding, the estimated annual ERISA pension funding for the Company allocable to Tennessee is $2,086,819. At the end of each of the Company's fiscal quarters, beginning with the quarter ended 12/31/2012, the Company will compare: 1) the actual cash contributions made to its pension plan and allocable to Tennessee using the pension allocation methodology filed by the Company in this proceeding, and 2) $521,705, which is $2,086,819 divided by 4. The Company shall establish a regulated asset or liability as appropriate for the difference between the two amounts. The net regulated asset or liability that has been accumulated by such treatment between 12/31/2012 and the end of the historic period of the Company's next petition shall be included in the rate base of the Company in that petition and amortized over a time period to be determined in that petition. The Company shall continue to apply this regulated asset / liability treatment to its pension funding contributions until such time in which an order from the Authority mandates alternative treatment.

c. That the depreciation rates supported by the testimony of Company witness Thomas Petersen are for the limited purpose of settlement of this docket are appropriate for use in this proceeding and should be approved by the Authority to be effective December 1, 2012.

d. That rate case expenses will be amortized over a period of three years, and $20,000 shall be paid to the Consumer Advocate from the Company's budgeted rate case expenses as a partial offset to expert accounting witness fees actually incurred by the Consumer Advocate in this proceeding.

e. That the normal heating degree days and WNA Factors set forth on Attachments C and E hereto are fair and reasonable and appropriate for use in this proceeding and should be approved by the Authority to be effective December 1, 2012.

f. That the period to which the WNA adjustment should apply going forward consists of the months of October through April of each year.

g. That the revised rate schedules and service regulations attached hereto as Attachment D and E are fair and reasonable for the limited purpose of settlement of this proceeding and should be approved by the Authority for bills rendered on or after December 1, 2012.

12. In light of the settlement terms as a whole and for the sole purposes of settlement, the Parties agree that the revised rates, tariffs, rate schedules, and service regulations agreed to herein, both individually and in the aggregate, are fair and reasonable to all customer classes and will provide Atmos with a reasonable opportunity to recover the agreed upon operating revenue requirement and a reasonable rate of turn on investment.

13. All pre-filed testimony and exhibits of the Parties are introduced into evidence without objection, and the Parties waive their right to cross-examine all witnesses with respect to all such pre-filed testimony. If, however, questions should be asked by any person, including a

Director, who is not a party to this stipulation, the Parties may present testimony and exhibits to respond to such questions and may cross-examine any witnesses with respect to such testimony and exhibits.

14. The Parties agree to support this Stipulation and Settlement Agreement before the Authority and in any hearing, proposed order, or brief conducted or filed in this proceeding; provided, however, that the settlement of any issue provided for herein shall not be cited as precedent by any of the Parties hereto in any unrelated or separate proceeding or docket before the Authority. The provisions of this Settlement Agreement are agreements reached in compromise and solely for the purpose of settlement of this matter. They do not necessarily reflect the positions asserted by any party, and no party to this Settlement Agreement waives the right to assert any position in any future proceeding, in this or any other jurisdiction. None of the signatories to this Settlement Agreement shall be deemed to have acquiesced in any ratemaking or accounting methodology or procedural principle, including without limitation, any cost of service determination or cost allocation or revenue-related methodology.

15. This Settlement Agreement shall not have any precedential effect in any future proceeding or be binding on any of the Parties in this or any other jurisdiction except to the limited extent necessary to implement the provisions hereof.

16. The Parties agree and request the Authority to order that the settlement of any issue pursuant to this Stipulation and Settlement Agreement shall not be cited by the Parties or any other entity as binding precedent in any other proceeding before the Authority or any court, state or federal.

17. The terms of the Settlement Agreement have resulted from extensive negotiations between the signatories and the terms hereof are interdependent. The Parties jointly recommend

that the Authority issue an order adopting this Stipulation and Settlement Agreement in its entirety without modification.

18. If the Authority does not accept the settlement in whole, the Parties are not bound by any position or term set forth in this Settlement Agreement. In the event that the Authority does not approve this Settlement Agreement in its entirety, each of the signatories to this Settlement Agreement will retain the right to terminate this Settlement Agreement. In the event of such action by the Authority, within twenty (20) business days, any of the signatories to this Settlement Agreement would be entitled to give notice of exercising its right to terminate this Settlement Agreement; provided, however, that the signatories to this Settlement Agreement could, by unanimous consent, elect to modify this Settlement Agreement to address any modification required by, or issues raised by, the Authority. Should this Settlement Agreement terminate, it would be considered void and have no binding precedential effect, and the signatories to this Settlement Agreement would reserve their rights to fully participate in all relevant proceedings notwithstanding their agreement to the terms of this Settlement Agreement.

19. In order to facilitate the execution of this Settlement Agreement and to achieve one of the purposes of this Agreement of avoiding the need for further litigation and expense, Atmos will not file rebuttal testimony that might have otherwise been filed, and the Consumer Advocate will not respond to the Company's outstanding discovery requests. However, in the event that any party and/or the Authority requires that hearings go forward, then the Parties agree that the Parties will move the Authority for the establishment of a procedural schedule that would permit the Parties to obtain responses to the outstanding discovery and to submit evidence and testimony that has not been submitted as a result of reaching this Agreement.

20. By agreeing to this Stipulation and Settlement Agreement, no Party waives any right to continue litigating this matter should the Stipulation and Settlement Agreement be rejected by the Authority in whole or in part.

21. No provision of this Stipulation and Settlement Agreement shall be deemed an admission of any Party. No provision of this Stipulation and Settlement Agreement shall be deemed a waiver of any position asserted by a party in this docket.

22. Approval by the Authority of the provisions of this Stipulation and Settlement Agreement shall not be construed as a waiver of the Authority's decisions in any rate case or policy decision or constitute an endorsement of any ratemaking methodology by the Authority.

23. This Stipulation and Settlement Agreement shall be governed by and construed under the law of the State of Tennessee and any applicable federal law, Tennessee choice of law rules notwithstanding.

The foregoing is agreed and stipulated to this 30th day of October, 2012.

ATMOS ENERGY CORPORATION

Scott Ross w/permission KCA

A. Scott Ross, #15634
Neal & Harwell, PLC
2000 One Nashville Place
150 Fourth Avenue, North
Nashville, TN 37219-2498
(615) 244-1713 – Telephone

CONSUMER ADVOCATE AND PROTECTION DIVISION

Robert E. Cooper, Jr., #10934
Attorney General and Reporter

Ryan L. McGehee, #25559
Assistant Attorney General
Office of the Attorney General
Consumer Advocate and Protection Division
P. O. Box 20207
Nashville, TN 37202-0207
(615) 532-5512 – Telephone

Docket 12-00064

ATMOS ENERGY CORPORATION

SETTLEMENT AGREEMENT ATTACHMENTS

	Attachment
Cost of Service Components	**A**
Rate Comparison	**B**
Smoothed Normal Heating Degree Days	**C**
Revised Rate Schedules	**D**
Tariffs	**E**

Docket 12-00064

ATMOS ENERGY CORPORATION

SETTLEMENT AGREEMENT

ATTACHMENT A

12-00064
Settlement Exhibit

ATMOS ENERGY CORPORATION
INDEX TO SCHEDULES
For the 12 Months Ending November 30, 2013

12-00064
Settlement Exhibit
Schedule 1

ATMOS ENERGY CORPORATION
Results of Operations
For the 12 Months Ending November 30, 2013

Line No.		CAPD A/	Company B/	Settlement
1	Rate Base	$ 183,493,088	$ 208,661,037	$ 201,359,443 C/
2	Operating Income At Current Rates	12,142,547	11,649,748	12,291,438 D/
3	Earned Rate Of Return	6.62%	5.58%	6.10%
4	Fair Rate Of Return	7.72%	8.75%	8.28% E/
5	Required Operating Income	14,161,967	18,257,841	16,677,604
6	Operating Income Deficiency	2,019,420	6,608,093	4,386,166
7	Gross Revenue Conversion Factor	1.618726	1.634495	1.618726 F/
8	Revenue Deficiency	$ 3,268,888	$ 10,800,897	$ 7,100,000

A/ Settlement Exhibit, Schedule 2.
B/ Company Exhibit, Schedules THP-1 and Schedule THP-10.
C/ Settlement Exhibit, Schedule 2.
D/ Settlement Exhibit, Schedule 6.
E/ Settlement Exhibit, Schedule 12.
F/ Settlement Exhibit, Schedule 13.

ATMOS ENERGY CORPORATION
Average Rate Base
For the 12 Months Ending November 30, 2013

Line No.		Test Period A/	Adjustments	Settlement Amount
	Additions:			
1	Utility Plant In Service	$ 394,722,350	$ 32,418,480	$ 427,140,830
2	Construction Work In Progress	6,111,881	-1,062,613	5,049,268
3	Gas Inventory	6,709,810	-868,752	5,841,058
4	Materials & Supplies	7,861	1,106	8,967
5	Deferred Rate Case Expense	0	383,333	383,333
6	Intercompany Leased Property	5,919,136	-90,626	5,828,510
7	Working Capital	607,429	-673,989	-66,560 B/
8	**Total Additions**	$ 414,078,467	$ 30,106,939	$ 444,185,406
	Deductions:			
9	Accumulated Depreciation	$ 171,525,585	$ 10,641,767	$ 182,167,352
10	Accumulated Deferred Income Taxes	41,869,830	8,089,325	49,959,155
11	Customer Advances for Construction	66,196	727	66,923
12	Customer Deposits	3,809,495	182,739	3,992,234
13	Accumulated Interest on Customer Deposits	81,314	-23,077	58,237
14	Misc. Rate Base Adjustment - Settlement	0	0	6,582,062
15	**Total Deductions**	$ 217,352,420	$ 18,891,481	$ 242,825,963
16	Rate Base	$ 196,726,047	$ 11,215,458	$ 201,359,443

A/ Company Exhibit, Schedule THP-7.
B/ Settlement Exhibit, Schedule 4.

12-00064
Settlement Exhibit
Schedule 3

ATMOS ENERGY CORPORATION
Comparative Rate Base
For the 12 Months Ending November 30, 2013

Line No.		CAPD A/	Company B/	Settlement Amount
	Additions:			
1	Utility Plant in Service	$ 422,567,115	$ 427,140,830	$ 427,140,830
2	Construction Work in Progress	4,590,230	5,049,268	5,049,268
3	Gas Inventory	5,841,058	5,841,058	5,841,058
4	Materials & Supplies	8,967	8,967	8,967
5	Deferred Rate Case Expense	383,333	383,333	383,333
6	Intercompany Leased Property	5,523,686	5,828,510	5,828,510
7	Working Capital	82,840	652,972	-66,560
8	**Total Additions**	$ 438,997,229	$ 444,904,938	$ 444,185,406
	Deductions:			
9	Accumulated Depreciation	$ 186,503,024	$ 182,167,352	$ 182,167,352
10	Accumulated Deferred Income Taxes	64,322,474	49,959,155	49,959,155
11	Operating Reserves	561,249	0	0
12	Customer Advances for Construction	66,923	66,923	66,923
13	Customer Deposits	3,992,234	3,992,234	3,992,234
14	Accumulated Interest on Customer Deposits	58,237	58,237	58,237
15	Misc. Rate Base Adjustment - Settlement	0	0	6,582,062
16	**Total Deductions**	$ 255,504,141	$ 236,243,901	$ 242,825,963
17	**Rate Base**	$ 183,493,088	$ 208,661,037	$ 201,359,443

A/ CAPD Rate Base Workpaper RB-1.00.
B/ Company Exhibit, Schedule THP-7.

12-00064
Settlement Exhibit
Schedule 4

ATMOS ENERGY CORPORATION
Lead Lag Results
For the 12 Months Ending November 30, 2013

Line No.		CAPD
1	Revenue Lag	36.48 A/
2	Expense Lag	36.68 B/
3	Net Lag	-0.20
4	Daily Cost of Service	$ 330,642 B/
5	**Lead Lag Study**	$ -66,174

A/ CAPD Rate Base Workpaper RB-40-1.00.
B/ Settlement Exhibit, Schedule 5.

ATMOS ENERGY CORPORATION
Working Capital Expense Lag
For the 12 Months Ending November 30, 2013

Line No.		Amount A/	Lag B/	Dollar Days
	Operating & Maintenance Expenses:			
1	Purchased Gas Expense	$ 68,279,615	39.46	$ 2,694,313,608
2	O&M Labor	3,732,632	14.14	52,779,416
3	O&M Non-Labor	15,122,891	22.78	344,499,457
	Taxes Other Than Income:			
4	Ad Valorem	3,270,467	241.50	789,817,781
5	State Gross Receipts Tax	1,319,687	-151.50	-199,932,581
6	Payroll Taxes	298,942	19.19	5,736,697
7	Franchise Tax	617,385	37.00	22,843,245
8	TRA Inspection Fee	422,746	272.00	114,986,912
9	DOT Fee	18,035	60.00	1,082,100
	Allocated Taxes - Shared Services:			
10	Ad Valorem	68,720	241.50	16,595,844
11	Payroll Taxes	219,424	19.19	4,210,749
	Allocated Taxes - Business Unit:			
12	Ad Valorem	41,376	241.50	9,992,222
13	Payroll Taxes	52,043	19.19	998,712
	Federal Income Tax:			
14	Current Taxes	0	37.00	0
15	Deferred Taxes	3,277,931	0.00	0
	State Excise Taxes:			
16	Current Taxes	0	37.00	0
17	Deferred Taxes	650,518	0.00	0
	Other:			
20	Depreciation Expense	10,870,894	0.00	0
21	Interest on Customer Deposits	129,748	15.50	2,011,094
22	Interest Expense - Long Term Debt	6,206,502	91.19	565,970,929
23	Interest Expense - Short Term Debt	33,998	24.05	817,641
24	Return on Equity	6,050,938	0.00	0
25	**Total Cost of Service**	$ 120,684,492	36.68	$ 4,426,723,825
26	**Daily Cost Of Service**	$ 330,642		

A/ Settlement Exhibit, Schedule 6.
B/ CAPD Rate Base Workpaper RB-40-1.00.

12-00064
Settlement Exhibit
Schedule 6

ATMOS ENERGY CORPORATION
Income Statement at Current Rates
For the 12 Months Ending November 30, 2013

Line No.		Test Period A/	Adjustments	Settlement Amount
	Operating Revenues:			
1	Gas Sales & Transportation Revenues	$ 120,398,800	$ -1,055,455	$ 119,343,345
2	Other Revenues	1,257,907	83,240	1,341,147
3	Total Gas Revenue	$ 121,656,707	$ -972,215	$ 120,684,492
	Operating & Maintenance Expenses:			
4	Purchased Gas Expense	$ 69,266,324	$ -986,709	$ 68,279,615
5	Operations & Maintenance - Labor	3,740,002	-7,370	3,732,632
6	Operations & Maintenance - NonLabor	13,574,113	1,548,778	15,122,891
7	Total Operating & Maintenance Expenses	$ 86,580,439	$ 554,699	$ 87,135,138
	Other Expenses:			
8	Depreciation Expense	$ 10,216,011	$ 654,883	$ 10,870,894
9	Interest on Customer Deposits	123,809	5,939	129,748
10	General Taxes	6,224,968	103,857	6,328,825
11	State Excise Taxes	811,258	-160,740	650,518
12	Federal Income Taxes	4,070,732	-792,801	3,277,931
13	Total Other Expenses	$ 21,446,778	$ -188,862	$ 21,257,916
14	Total Operating Expenses	$ 108,027,217	$ 365,837	$ 108,393,054
15	Utility Operating Income	$ 13,629,490	$ -1,338,052	$ 12,291,438

A/ Company Schedule THP-10.

12-00064
Settlement Exhibit
Schedule 7

ATMOS ENERGY CORPORATION
Comparative Income Statement at Current Rates
For the 12 Months Ending November 30, 2013

Line No.		CAPD A/	Company B/	Settlement C/
	Operating Revenues:			
1	Gas Sales & Transportation Revenues	$ 119,343,345	$ 120,925,697	$ 119,343,345
2	Other Revenues	1,453,532	1,257,907	1,341,147
3	**Total Gas Revenue**	$ 120,796,877	$ 122,183,604	$ 120,684,492
	Operating & Maintenance Expenses:			
4	Purchased Gas Expense	$ 68,279,615	$ 69,266,324	$ 68,279,615
5	Operations & Maintenance - Labor	3,732,632	3,857,085	3,732,632
6	Operations & Maintenance - NonLabor	15,122,891	17,012,671	15,122,891
7	**Total Operating & Maintenance Expenses**	87,135,138	90,136,080	87,135,138
	Other Expenses:			
8	Depreciation Expense	$ 10,870,894	$ 10,620,298	$ 10,870,894
9	Interest on Customer Deposits	129,748	129,748	129,748
10	General Taxes	6,328,825	6,262,934	6,328,825
11	State Excise Taxes	693,814	1,260,891	650,518
12	Federal Income Taxes	3,495,911	6,345,271	3,277,931
13	**Total Other Expenses**	$ 21,519,192	$ 24,619,142	$ 21,257,916
14	**Total Operating Expenses**	$ 108,654,330	$ 114,755,222	$ 108,393,054
15	**Utility Operating Income**	$ 12,142,547	$ 7,428,382	$ 12,291,438

A/ CAPD Exhibit, Schedule 6.
B/ Company Exhibit, Schedule THP-1.
C/ Settlement Exhibit, Schedule 6.

12-00064
Settlement Exhibit
Schedule 8

ATMOS ENERGY CORPORATION
Comparative Margin Summary
For the 12 Months Ending November 30, 2013

Line No.	Customer Class	CAPD A/	Company B/	Settlement
1	Residential (210) / Public Housing (225)	$ 26,216,179	$ 26,809,914	$ 26,216,179
2	Heating & Cooling (211)	598	725	598
3	Small Commercial & Industrial (220)	16,672,111	16,656,897	16,672,111
4	Experimental School (221)	74,599	69,243	74,599
5	Large Commercial & Industrial (230)	351,391	366,301	351,391
6	Demand/Commodity (240)	368,171	368,171	368,171
7	Interruptible (250)	568,144	568,144	568,144
8	Transportation (260)	6,228,516	6,235,956	6,228,516
9	Negotiated/Special Contract (291)	560,261	560,261	560,261
10	Cogeneration (292)	2,005	2,006	2,005
11	Large Tonnage Air Conditioning (293)	21,755	21,755	21,755
12	**Total Sales & Transportation Revenue**	$ 51,063,730	$ 51,659,373	$ 51,063,730
13	Other Revenues	1,453,532	1,257,907	1,341,147
14	**Total Revenues**	$ 52,517,262	$ 52,917,280	$ 52,404,877

A/ CAPD Revenue Workpaper R-1.00.
B/ Company Response to MFR#12, Attachment #1, Schedule JCD-2.

ATMOS ENERGY CORPORATION
Taxes Other than Income Income Taxes
For the 12 Months Ending November 30, 2013

Line No.		CAPD A/	Company B/	Settlement
1	Property Taxes	$ 3,270,467	$ 3,307,000	$ 3,270,467
2	TRA Inspection Fee	422,746	433,803	422,746
3	Payroll Taxes	298,942	280,781	298,942
4	Franchise Tax	617,385	602,000	617,385
5	Gross Receipts Tax	1,319,687	1,228,602	1,319,687
6	Allocated & Other Taxes	399,598	399,598	399,598
7	Total	$ 6,328,825	$ 6,251,784	$ 6,328,825

A/ CAPD Expense Workpaper T-OTAX-0.
B/ Company Exhibit, Schedule GW-3.

ATMOS ENERGY CORPORATION
Excise and Income Taxes
For the 12 Months Ending November 30, 2013

Line No.		Settlement	
1	**Operating Revenues**	$ 120,684,492	A/
	Operating Expenses:		
2	O&M Expenses	$ 87,135,138	A/
3	Depreciation Expense	10,870,894	A/
4	Interest on Customer Deposits	129,748	A/
5	General Taxes	6,328,825	A/
6	**Total Operating Expenses**	$ 104,464,605	
7	**NOI Before Excise and Income Taxes**	$ 16,219,887	
8	AFUDC	-28,577	B/
9	Interest Expense	6,240,500	C/
10	**Pre-tax Book Income**	$ 10,007,964	
11	Schedule M Adjustments	10,007,964	D/
12	**Excise Taxable Income**	$ 0	
13	Excise Tax Rate	6.50%	
14	**Excise Tax Payable**	$ 0	
15	Excise Tax - Deferred	650,518	
16	**State Excise Tax Expense**	$ 650,518	
17	**Pre-tax Book Income**	$ 10,007,964	
18	State Excise Tax Expense	650,518	
19	Schedule M Adjustments	9,357,447	D/
20	**FIT Taxable Income**	$ 0	
21	FIT Rate	35.00%	
22	**Federal Income Tax Payable**	$ 0	
23	ITC Amortization	2,825	E/
24	FIT - Deferred	3,275,106	
25	**Federal Income Tax Expense**	$ 3,277,931	

A/ Settlement Exhibit, Schedule 6.
B/ CAPD Expense Workpaper E-REC-1.
C/ Settlement Exhibit, Schedule 12.
D/ All Pre-tax book income assumed to be deferred.
E/ Company Schedule 10-1.

ATMOS ENERGY CORPORATION
Income Statement at Proposed Rates
For the 12 Months Ending November 30, 2013

Line No.		Current Rates A/	Settlement Rate Increase B/	Proposed Rates
	Operating Revenues:			
1	Gas Sales & Transportation Revenues	$ 119,343,345	$ 7,100,000	$ 126,443,345
2	Other Revenues	1,341,147	134,176	1,475,323
3	Total Gas Revenue	$ 120,684,492	$ 7,234,176	$ 127,918,668
	Operating & Maintenance Expenses:			
4	Purchased Gas Expense	$ 68,279,615	$	$ 68,279,615
5	Operations & Maintenance - Labor	3,732,632		3,732,632
6	Operations & Maintenance - NonLabor	15,122,891	17,124	15,140,015
7	Total Operating & Maintenance Expenses	$ 87,135,138	$ 17,124	$ 87,152,262
	Other Expenses:			
8	Depreciation Expense	$ 10,870,894	$	$ 10,870,894
9	Interest on Customer Deposits	129,748		129,748
10	General Taxes	6,328,825		6,328,825
11	State Excise Taxes	650,518	469,108	1,119,626
12	Federal Income Taxes	3,277,931	2,361,780	5,639,712
13	Total Other Expenses	$ 21,257,916	$ 2,830,889	$ 24,088,805
14	Total Operating Expenses	$ 108,393,054	$ 2,848,013	$ 111,241,067
15	Utility Operating Income	$ 12,291,438	$ 4,386,163	$ 16,677,601

A/ Settlement Exhibit, Schedule 6.
B/ Settlement Exhibit, Schedule 1.

ATMOS ENERGY CORPORATION
Rate of Return Summary
For the 12 Months Ending November 30, 2013

Line No.	Class of Capital	Settlement Percent of Total	Settlement Cost Rate	Settlement Weighted Cost Rate A/
1	Short-Term Debt	1.26%	1.34%	0.02%
2	Long-Term Debt	47.42%	6.50%	3.08%
3	Common Equity	51.32%	10.10% C/	5.18%
4	**Total**	100.00%		8.28%

Line No.			
	Interest Expense Short-Term Debt:		
5	Rate Base	$	201,359,443 B/
6	Short-Term Weighted Debt Cost		0.02%
7	**Short-Term Debt Interest Expense**	$	33,998
	Interest Expense Long-Term Debt:		
8	Rate Base	$	201,359,443 B/
9	Long-Term Weighted Debt Cost		3.08%
10	**Long-Term Debt Interest Expense**	$	6,206,502
11	**Total Interest Expense**	$	6,240,500

A/ Structure per Klein Exhibit, Page 2 of 17 and Company Schedule THP-9.
B/ CAPD Exhibit, Schedule 2.
C/ Settlement Return.

ATMOS ENERGY CORPORATION
Revenue Conversion Factor
For the 12 Months Ending November 30, 2013

Line No.		Settlement Amount	Balance
1	Operating Revenues		1.000000
2	Add: Forfeited Discounts	0.018898 A/	0.018898
3	Balance		1.018898
4	Uncollectible Ratio	0.002367 B/	0.002412
5	Balance		1.016486
6	State Excise Tax	0.065000 C/	0.066072
7	Balance		0.950415
8	Federal Income Tax	0.350000 C/	0.332645
9	Balance		0.617769
10	Revenue Conversion Factor (Line 1 / Line 9)		1.618726

A/ CAPD Revenue Workpaper R-96-2.00.
B/ CAPD Expense Workpaper E-CA.
C/ Statutory Rates.

ATMOS ENERGY CORPORATION
CAPD Proposed Revenue Change
For the 12 Months Ending November 30, 2013

Line No.	Customer Class	Current Rates A/	Settlement Proposed Rates	Settlement Revenue Change B/	Percent Change
1	Residential (210)	$ 26,216,179	$ 29,955,601	$ 3,739,422	14.26%
2	Heating & Cooling (211)	598	699	101	16.89%
3	Small Commercial & Industrial (220)	16,672,111	18,992,948	2,320,837	13.92%
4	Experimental School (221)	74,599	84,257	9,658	12.95%
5	Large Commercial & Industrial (230)	351,391	419,042	67,651	19.25%
6	Demand/Commodity (240)	368,171	392,318	24,147	6.56%
7	Interruptible (250)	568,144	662,513	94,369	16.61%
8	Transportation (260)	6,228,516	7,069,368	840,852	13.50%
9	Negotiated/Special Contract (291)	560,261	560,261	0	0.00%
10	Cogeneration (292)	2,005	2,254	249	12.42%
11	Large Tonnage Air Conditioning (293)	21,755	24,469	2,714	12.48%
12	**Total Sales & Transportation Revenue**	$ 51,063,730	$ 58,163,730	$ 7,100,000	13.90%
13	Other Revenues	1,341,147	1,475,323	134,176	10.00%
14	**Total Revenues**	$ 52,404,877	$ 59,639,053	$ 7,234,176	13.80%

A/ Settlement Exhibit, Schedule 8.
B/ Settlement Exhibit, Schedule 11.

Docket 12-00064

ATMOS ENERGY CORPORATION

SETTLEMENT AGREEMENT

ATTACHMENT B

ATMOS ENERGY CORPORATION
For the 12 Months Ending November 30, 2013

Line No.	Customer Class	Current Rates	Proposed Rates	Revenue Change
1	Residential (210) / Public Housing (225)	$ 26,216,179	$ 29,955,600	$ 3,739,421
2	Heating & Cooling (211)	598	699	101
3	Small Commercial & Industrial (220)	16,672,111	18,992,948	2,320,837
4	Experimental School (221)	74,599	84,257	9,658
5	Large Commercial & Industrial (230)	351,391	419,042	67,651
6	Demand/Commodity (240)	368,171	392,318	24,147
7	Interruptible (250)	568,144	662,513	94,369
8	Transportation (260)	6,228,516	7,069,368	840,852
9	Special Contract	560,261	560,261	0
10	Cogeneration (292)	2,005	2,254	249
11	Large Tonnage Air Conditioning (293)	21,755	24,469	2,714
12	**Total Sales & Transportation Revenue**	$ 51,063,730	$ 58,163,730	$ 7,100,000
13	Other Revenues	1,341,147	1,341,147	0
14	**Total Revenues**	$ 52,404,877	$ 59,504,877	$ 7,100,000

Docket 12-00064

ATMOS ENERGY CORPORATION

SETTLEMENT AGREEMENT

ATTACHMENT C

PADUCAH CALENDAR HEATING DDD
CAPD NORMAL DAILY WEATHER (30 YEAR ENDING MARCH 2012)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	28	25	21	12	4	0	0	0	0	3	9	24
2	28	26	20	10	4	0	0	0	0	4	13	22
3	28	27	23	9	5	0	0	0	0	4	15	22
4	28	26	20	12	4	0	0	0	0	4	16	23
5	30	30	18	12	2	0	0	0	0	4	16	25
6	26	29	18	12	3	0	0	0	0	5	16	26
7	29	29	18	10	2	0	0	0	0	5	14	26
8	30	29	18	10	2	0	0	0	0	5	13	25
9	29	29	20	12	1	0	0	0	0	4	13	26
10	30	27	21	10	2	0	0	0	0	6	14	26
11	29	27	19	7	2	0	0	0	0	6	16	26
12	28	29	17	8	2	0	0	0	0	6	17	27
13	29	27	16	8	2	0	0	0	0	8	17	26
14	30	24	16	8	2	0	0	0	0	7	16	24
15	32	25	15	6	2	0	0	0	1	6	17	25
16	29	26	15	8	2	0	0	0	1	6	19	26
17	28	26	14	8	2	0	0	0	1	7	19	27
18	32	24	13	7	2	0	0	0	0	8	17	28
19	33	23	14	5	1	0	0	0	1	9	15	29
20	32	20	15	5	1	0	0	0	1	9	15	29
21	31	20	16	6	1	0	0	0	2	8	18	27
22	30	21	15	5	1	0	0	0	2	9	18	27
23	28	22	13	6	1	0	0	0	3	9	19	29
24	28	28	13	5	1	0	0	0	3	10	21	32
25	31	23	13	4	1	0	0	0	3	9	20	34
26	31	22	11	5	1	0	0	0	3	9	18	32
27	30	22	12	5	1	0	0	0	3	10	18	28
28	29	23	11	5	0	0	0	0	2	11	21	27
29	28	6	12	4	1	0	0	0	4	10	20	27
30	30		13	3	0	0	0	0	3	9	21	27
31	28		13		0		0	0		8		26
Calendar Total	913	708	495	227	53	2	0	1	34	214	490	827

PADUCAH CALENDAR HEATING DDD
NOAA 30 YEAR NORMAL DAILY WEATHER (1981 - 2010)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	29	30	21	13	4	1	0	0	0	4	12	23
2	29	29	21	12	4	1	0	0	0	4	12	24
3	29	29	21	12	4	1	0	0	0	4	12	24
4	30	29	21	11	3	1	0	0	0	5	12	24
5	31	28	20	11	3	0	0	0	0	5	13	25
6	31	28	20	11	3	0	0	0	0	5	13	25
7	31	28	20	10	3	0	0	0	0	5	14	25
8	31	28	19	10	3	0	0	0	0	6	14	25
9	31	27	19	10	3	0	0	0	0	6	14	26
10	31	27	19	10	3	0	0	0	0	6	15	26
11	31	27	18	9	3	0	0	0	0	6	15	27
12	31	27	18	9	2	0	0	0	0	6	15	27
13	31	26	18	9	2	0	0	0	1	7	16	27
14	31	26	17	9	2	0	0	0	1	7	16	28
15	31	26	17	8	2	0	0	0	1	7	17	28
16	31	26	17	8	2	0	0	0	1	7	17	28
17	31	25	17	8	2	0	0	0	1	7	17	28
18	31	25	16	7	2	0	0	0	1	8	18	28
19	31	25	16	7	2	0	0	0	1	8	18	29
20	31	24	16	7	2	0	0	0	2	8	19	29
21	30	24	15	7	1	0	0	0	2	8	19	29
22	30	24	15	6	1	0	0	0	2	9	20	29
23	30	23	15	6	1	0	0	0	2	9	20	29
24	30	23	14	6	1	0	0	0	2	9	20	29
25	30	23	14	6	1	0	0	0	3	9	21	30
26	30	22	14	6	1	0	0	0	3	10	21	30
27	30	22	14	5	1	0	0	0	3	10	22	30
28	30	22	13	5	1	0	0	0	3	10	22	30
29	30	22	13	5	1	0	0	0	4	11	23	30
30	30		13	4	0	0	0	0	6	11	23	30
31	29		12		1		0	1		11		30
Calendar Total	942	748	523	245	84	4	0	1	39	228	510	854

TO BE USED IN BILLING
PADUCAH CALENDAR HEATING DDD
SMOOTHED CAPD NORMAL DAILY WEATHER (30 YEAR ENDING MARCH 2012)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	28	29	20	12	3	1	0	0	0	4	12	22
2	28	28	20	11	3	1	0	0	0	4	12	23
3	28	28	20	11	3	1	0	0	0	4	12	23
4	29	28	20	10	2	1	0	0	0	5	12	23
5	30	27	19	10	2	0	0	0	0	5	13	24
6	30	27	19	10	2	0	0	0	0	5	13	24
7	30	27	19	9	2	0	0	0	0	5	14	25
8	30	27	18	9	2	0	0	0	0	6	14	25
9	30	26	18	9	2	0	0	0	0	6	14	25
10	30	26	18	9	2	0	0	0	0	6	15	25
11	30	26	17	8	2	0	0	0	0	6	15	26
12	30	26	17	8	2	0	0	0	0	6	15	26
13	30	25	17	8	2	0	0	0	1	7	16	26
14	30	26	16	8	2	0	0	0	1	7	16	27
15	30	25	16	7	2	0	0	0	1	7	17	27
16	30	25	16	7	2	0	0	0	1	7	17	27
17	30	24	16	7	2	0	0	0	1	7	17	27
18	30	24	16	6	2	0	0	0	1	8	18	27
19	30	24	15	6	2	0	0	0	1	8	18	28
20	30	23	15	6	2	0	0	0	2	8	19	28
21	29	23	14	6	1	0	0	0	2	8	19	28
22	29	23	14	6	1	0	0	0	2	8	20	28
23	29	23	14	6	1	0	0	0	2	8	20	28
24	29	22	13	6	1	0	0	0	2	8	20	28
25	29	22	13	5	1	0	0	0	3	8	21	29
26	29	21	13	5	1	0	0	0	3	9	21	29
27	29	21	13	5	1	0	0	0	3	9	22	29
28	29	21	12	5	1	0	0	0	3	9	22	29
29	29	21	12	5	1	0	0	0	4	10	23	29
30	29		12	4	0	0	0	0	4	10	23	29
31	28		11		1		0	1		10		29
Calendar Total	913	708	495	227	53	2	0	1	34	214	489	827

BRISTOL CALENDAR HEATING DDD
CAPD NORMAL DAILY WEATHER (30 YEAR ENDING MARCH 2012)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	26	26	22	14	4	1	0	0	0	6	11	23
2	27	26	21	13	5	1	0	0	0	6	12	24
3	27	26	21	12	5	0	0	0	0	6	14	23
4	27	26	20	12	6	0	0	0	0	5	16	25
5	28	30	19	13	6	1	0	0	1	6	17	26
6	28	28	18	13	5	1	0	0	0	6	18	27
7	28	28	19	14	4	1	0	0	0	7	17	27
8	29	29	19	12	4	0	0	0	0	7	17	28
9	29	28	20	13	4	0	0	0	0	6	18	25
10	28	27	22	12	3	0	0	0	0	5	16	24
11	30	27	21	10	3	0	0	0	0	5	18	25
12	29	28	19	10	3	0	0	0	0	7	18	28
13	28	28	18	11	3	0	0	0	0	7	19	25
14	30	26	17	8	3	0	0	0	1	8	18	25
15	30	24	17	8	3	0	0	0	1	9	17	24
16	30	25	17	10	4	0	0	0	2	9	18	26
17	29	26	18	11	4	0	0	0	2	9	20	28
18	29	25	16	9	4	0	0	0	1	10	19	27
19	31	23	16	9	4	0	0	0	1	10	18	28
20	32	22	16	7	3	0	0	0	1	11	17	29
21	32	19	16	7	2	0	0	0	1	11	19	28
22	30	21	18	8	3	0	0	0	2	11	20	27
23	29	21	16	8	2	0	0	0	3	11	20	27
24	29	23	15	8	2	0	0	0	3	10	19	29
25	31	24	14	7	2	0	0	0	3	11	19	31
26	30	24	14	8	1	0	0	0	3	10	19	31
27	31	23	13	7	2	0	0	0	3	11	18	28
28	28	22	12	8	2	0	0	0	4	12	18	28
29	27	6	13	7	2	0	0	0	5	13	21	27
30	25		12	5	1	0	0	0	5	11	22	27
31	26		14		1		0	0		11		26
Calendar Total	893	711	635	291	97	7	0	1	43	285	531	816

BRISTOL CALENDAR HEATING DDD
NOAA 30 YEAR NORMAL DAILY WEATHER (1981 - 2010)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	30	29	22	14	7	2	0	0	0	5	14	23
2	30	29	22	14	6	2	0	0	0	5	14	24
3	30	28	22	13	6	1	0	0	0	5	14	24
4	30	28	22	13	6	1	0	0	0	6	15	25
5	30	28	21	13	6	1	0	0	0	6	15	25
6	30	28	21	13	5	1	0	0	0	6	15	26
7	30	28	21	12	5	1	0	0	0	7	15	26
8	30	28	20	12	5	1	0	0	0	7	16	26
9	30	27	20	12	5	1	0	0	0	7	16	26
10	30	27	20	12	4	0	0	0	1	7	16	26
11	30	27	20	11	4	0	0	0	1	8	17	26
12	30	27	19	11	4	0	0	0	1	8	17	27
13	30	26	19	11	4	0	0	0	1	8	17	27
14	30	26	19	11	4	0	0	0	1	9	18	27
15	30	26	19	10	4	0	0	0	1	9	18	27
16	30	26	18	10	3	0	0	0	1	9	18	28
17	30	26	18	10	3	0	0	0	2	9	19	28
18	30	25	18	9	3	0	0	0	2	10	19	28
19	30	25	18	9	3	0	0	0	2	10	20	28
20	30	25	17	9	3	0	0	0	2	10	20	28
21	30	25	17	9	3	0	0	0	2	11	20	28
22	30	24	17	8	3	0	0	0	3	11	21	29
23	30	24	16	8	2	0	0	0	3	11	21	29
24	30	24	16	8	2	0	0	0	3	11	21	29
25	30	23	16	8	2	0	0	0	3	12	22	29
26	30	23	16	7	2	0	0	0	4	12	22	29
27	29	23	15	7	2	0	0	0	4	12	22	29
28	29	23	15	7	2	0	0	0	4	12	23	29
29	29	23	15	7	1	0	0	0	5	13	23	29
30	29		15	6	1	0	0	0	6	13	23	30
31	29		14		1		0	1		13		30
Calendar Total	925	751	586	304	109	11	0	1	52	282	581	843

TO BE USED IN BILLING
BRISTOL CALENDAR HEATING DDD
SMOOTHED CAPD NORMAL DAILY WEATHER (30 YEAR ENDING MARCH 2012)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	29	27	21	13	6	1	0	0	0	5	13	22
2	29	27	21	13	5	1	0	0	0	5	13	23
3	29	27	21	12	5	1	0	0	0	5	13	23
4	29	27	21	12	4	1	0	0	0	6	14	24
5	29	27	20	12	4	1	0	0	0	6	14	24
6	29	27	20	12	4	1	0	0	0	6	14	24
7	29	27	20	11	4	1	0	0	0	7	14	24
8	29	27	19	11	4	1	0	0	0	7	15	25
9	29	26	19	11	4	1	0	0	0	7	16	25
10	29	26	19	11	4	0	0	0	1	7	16	25
11	29	26	18	11	4	0	0	0	1	8	16	25
12	29	26	18	11	4	0	0	0	1	8	16	26
13	29	25	18	11	4	0	0	0	1	8	16	26
14	29	25	18	11	4	0	0	0	1	8	17	26
15	29	25	18	10	4	0	0	0	1	8	17	26
16	29	26	17	10	3	0	0	0	1	8	17	27
17	29	25	17	10	3	0	0	0	2	8	17	27
18	29	24	17	9	3	0	0	0	2	9	18	27
19	29	24	17	9	3	0	0	0	2	9	18	27
20	29	24	16	9	3	0	0	0	2	9	19	27
21	29	24	16	9	3	0	0	0	2	10	19	27
22	29	23	16	8	3	0	0	0	2	10	20	28
23	29	23	15	8	2	0	0	0	2	10	20	28
24	29	23	15	8	2	0	0	0	2	10	20	28
25	29	22	15	8	2	0	0	0	2	11	21	28
26	29	22	15	7	2	0	0	0	3	11	21	28
27	28	22	14	7	2	0	0	0	3	11	21	28
28	28	22	14	7	2	0	0	0	3	11	22	28
29	28	22	14	7	1	0	0	0	4	12	22	28
30	28		14	6	1	0	0	0	5	12	22	29
31	28		13		1		0	1		12		29
Calendar Total	893	711	635	291	97	7	0	1	43	286	531	816

KNOXVILLE CALENDAR HEATING DDD
CAPD NORMAL DAILY WEATHER (30 YEAR ENDING MARCH 2012)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	24	23	19	11	3	1	0	0	0	3	8	21
2	26	22	18	11	3	0	0	0	0	3	10	21
3	25	23	19	10	4	0	0	0	0	3	12	21
4	25	26	19	9	5	0	0	0	0	3	13	22
5	25	27	18	11	4	0	0	0	0	3	14	23
6	25	28	16	10	3	0	0	0	0	4	16	24
7	24	28	16	11	3	0	0	0	0	5	14	24
8	27	28	15	9	2	0	0	0	0	5	14	24
9	26	25	17	10	2	0	0	0	0	4	13	22
10	28	24	19	8	2	0	0	0	0	4	14	21
11	27	24	18	7	2	0	0	0	0	4	15	22
12	28	26	16	7	2	0	0	0	0	5	18	23
13	28	25	14	7	2	0	0	0	0	5	16	23
14	27	22	14	8	1	0	0	0	0	5	16	23
15	27	22	14	8	1	0	0	0	0	6	16	22
16	28	21	13	8	2	0	0	0	1	7	18	23
17	27	23	14	8	2	0	0	0	0	7	18	23
18	27	22	13	7	2	0	0	0	0	7	16	25
19	28	20	12	8	2	0	0	0	0	8	16	26
20	29	18	13	5	1	0	0	0	1	8	14	26
21	29	17	14	5	1	0	0	0	1	7	16	25
22	27	18	15	6	1	0	0	0	1	8	17	25
23	27	18	13	6	1	0	0	0	2	9	17	25
24	28	20	12	6	1	0	0	0	2	8	17	27
25	28	21	11	5	1	0	0	0	2	9	17	28
26	28	20	11	5	1	0	0	0	1	8	17	28
27	28	19	10	5	1	0	0	0	2	10	16	25
28	25	19	10	5	1	0	0	0	2	11	18	24
29	23	6	10	5	1	0	0	0	2	11	20	26
30	23		10	3	1	0	0	0	3	9	20	25
31	24		12		1		0	0		8		23
Calendar Total	812	627	444	216	67	2	0	0	21	194	457	742

KNOXVILLE CALENDAR HEATING DDD
NOAA 30 YEAR NORMAL DAILY WEATHER (1981 - 2010)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	26	26	20	11	4	1	0	0	0	3	10	21
2	27	25	19	11	4	1	0	0	0	3	11	21
3	27	25	18	10	3	1	0	0	0	3	11	21
4	27	25	18	10	3	1	0	0	0	3	12	22
5	27	25	18	10	3	0	0	0	0	3	12	22
6	27	25	18	10	3	0	0	0	0	4	12	22
7	27	25	17	9	3	0	0	0	0	4	12	22
8	27	24	17	9	3	0	0	0	0	4	13	23
9	27	24	17	9	3	0	0	0	0	4	13	23
10	27	24	16	8	2	0	0	0	0	5	13	23
11	27	24	16	8	2	0	0	0	0	5	14	24
12	27	23	16	8	2	0	0	0	0	5	14	24
13	27	23	16	8	2	0	0	0	0	5	15	24
14	27	23	15	8	2	0	0	0	0	6	16	24
15	27	23	15	7	2	0	0	0	0	6	15	24
16	27	22	15	7	2	0	0	0	1	6	16	25
17	27	22	15	7	2	0	0	0	1	6	16	25
18	27	22	14	7	2	0	0	0	1	7	16	25
19	27	22	14	6	1	0	0	0	1	7	17	25
20	27	21	14	6	1	0	0	0	1	7	17	25
21	27	21	13	6	1	0	0	0	1	8	17	26
22	27	21	13	6	1	0	0	0	1	8	18	26
23	27	21	13	5	1	0	0	0	1	8	18	26
24	27	20	13	5	1	0	0	0	1	8	18	26
25	28	20	12	5	1	0	0	0	2	9	19	26
26	28	20	12	5	1	0	0	0	2	9	19	26
27	28	19	12	5	1	0	0	0	2	9	19	26
28	28	19	12	4	1	0	0	0	2	9	20	26
29	28	19	11	4	1	0	0	0	3	10	20	26
30	28		11	3	0	0	0	0	3	11	20	27
31	28		11		0		0	0		11		27
Calendar Total	829	653	461	215	68	4	0	0	23	198	462	752

TO BE USED IN BILLING
KNOXVILLE CALENDAR HEATING DDD
SMOOTHED CAPD NORMAL DAILY WEATHER (30 YEAR ENDING MARCH 2012)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	26	25	19	11	4	1	0	0	0	3	10	21
2	26	24	18	11	4	1	0	0	0	3	11	21
3	26	24	17	10	3	1	0	0	0	3	11	21
4	26	24	17	10	2	1	0	0	0	3	12	22
5	26	24	17	10	3	0	0	0	0	3	12	22
6	26	24	17	10	3	0	0	0	0	4	12	22
7	26	24	16	9	3	0	0	0	0	4	12	22
8	26	23	16	9	3	0	0	0	0	4	13	23
9	26	23	16	9	3	0	0	0	0	4	13	23
10	26	23	15	9	2	0	0	0	0	5	13	23
11	26	23	15	8	2	0	0	0	0	5	14	24
12	26	22	15	8	2	0	0	0	0	5	14	24
13	26	22	15	8	2	0	0	0	0	6	15	24
14	26	22	14	8	2	0	0	0	0	6	16	24
15	26	22	14	7	2	0	0	0	0	6	15	24
16	26	21	14	7	2	0	0	0	1	6	16	25
17	26	21	14	7	2	0	0	0	1	6	16	25
18	26	21	13	7	2	0	0	0	1	7	16	25
19	26	21	13	6	1	0	0	0	1	7	17	25
20	26	20	13	6	1	0	0	0	1	7	17	25
21	26	20	13	6	1	0	0	0	1	8	17	25
22	26	20	13	6	1	0	0	0	1	8	18	26
23	26	20	13	5	1	0	0	0	1	8	18	26
24	26	19	13	5	1	0	0	0	1	8	18	26
25	26	19	12	5	1	0	0	0	2	9	18	26
26	25	19	12	5	1	0	0	0	2	9	18	26
27	25	18	12	5	1	0	0	0	2	9	19	26
28	25	18	12	4	1	0	0	0	2	9	20	26
29	25	18	11	4	1	0	0	0	3	10	20	26
30	25		11	3	0	0	0	0	3	11	20	27
31	25		11		0		0	0		11		27
Calendar Total	812	627	444	216	67	2	0	0	21	194	457	742

NASHVILLE CALENDAR HEATING DDD
CAPD NORMAL DAILY WEATHER (30 YEAR ENDING MARCH 2012)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	25	22	19	11	3	0	0	0	0	3	8	21
2	25	22	17	9	3	0	0	0	0	3	10	21
3	25	24	19	8	4	0	0	0	0	3	12	20
4	25	26	17	10	4	0	0	0	0	3	13	21
5	26	27	17	11	3	0	0	0	0	3	13	23
6	25	26	18	11	2	0	0	0	0	4	15	24
7	25	26	18	9	2	0	0	0	0	5	13	24
8	27	25	16	8	2	0	0	0	0	4	12	22
9	26	25	17	10	2	0	0	0	0	4	12	21
10	25	25	19	9	2	0	0	0	0	4	13	23
11	27	24	17	6	1	0	0	0	0	4	14	23
12	25	26	16	8	1	0	0	0	0	4	18	24
13	25	25	14	7	2	0	0	0	0	4	16	23
14	27	22	14	6	2	0	0	0	0	5	14	22
15	28	22	14	7	2	0	0	0	0	5	14	22
16	27	22	14	7	2	0	0	0	0	6	16	24
17	29	23	13	8	2	0	0	0	0	6	17	23
18	28	21	12	6	2	0	0	0	0	6	18	25
19	30	21	13	5	1	0	0	0	0	8	13	26
20	29	18	13	6	1	0	0	0	0	8	14	28
21	29	16	15	5	1	0	0	0	1	7	16	25
22	27	19	14	5	1	0	0	0	2	7	17	25
23	28	19	12	5	0	0	0	0	2	7	18	26
24	28	20	12	6	0	0	0	0	2	8	17	28
25	28	21	11	4	1	0	0	0	1	8	18	31
26	28	20	11	4	0	0	0	0	2	8	15	29
27	28	19	10	5	0	0	0	0	2	9	15	23
28	26	20	9	6	0	0	0	0	2	10	17	23
29	24	5	10	4	1	0	0	0	2	9	19	24
30	26		11	3	1	0	0	0	2	9	19	24
31	25		11		0		0	0		0		22
Calendar Total	817	631	436	203	49	1	0	0	20	178	436	738

NASHVILLE CALENDAR HEATING DDD
NOAA 30 YEAR NORMAL DAILY WEATHER (1981 - 2010)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	26	26	19	11	4	1	0	0	0	2	9	20
2	26	26	19	11	3	1	0	0	0	3	11	21
3	27	26	19	10	3	1	0	0	0	3	11	22
4	27	26	19	10	3	0	0	0	0	3	11	22
5	27	26	18	10	3	0	0	0	0	4	12	22
6	28	25	18	10	3	0	0	0	0	4	12	22
7	28	25	18	9	3	0	0	0	0	4	12	23
8	28	25	18	9	3	0	0	0	0	4	13	23
9	28	25	17	9	2	0	0	0	0	4	13	23
10	28	25	17	9	2	0	0	0	0	5	13	24
11	28	24	17	8	2	0	0	0	0	5	14	24
12	28	24	16	8	2	0	0	0	0	5	14	24
13	28	24	16	8	2	0	0	0	0	5	14	24
14	28	24	16	8	2	0	0	0	0	5	15	25
15	28	23	16	7	2	0	0	0	0	6	15	25
16	28	23	15	7	2	0	0	0	1	6	15	25
17	28	23	15	7	2	0	0	0	1	6	16	25
18	28	23	15	7	2	0	0	0	1	7	16	25
19	28	22	14	6	1	0	0	0	1	7	17	26
20	27	22	14	6	1	0	0	0	1	7	17	26
21	27	22	14	6	1	0	0	0	1	7	17	26
22	27	21	14	6	1	0	0	0	1	8	18	26
23	27	21	13	5	1	0	0	0	1	8	18	26
24	27	21	13	5	1	0	0	0	2	8	18	26
25	27	21	13	5	1	0	0	0	2	8	19	26
26	27	20	12	5	1	0	0	0	2	9	19	27
27	27	20	12	4	1	0	0	0	2	9	19	27
28	27	20	12	4	1	0	0	0	2	9	20	27
29	27	20	12	4	1	0	0	0	2	9	20	27
30	27		11	3	1	0	0	0	4	10	21	27
31	26		11		0		0	0		10		27
Calendar Total	848	673	473	217	57	3	0	0	24	191	459	783

TO BE USED IN BILLING
NASHVILLE CALENDAR HEATING DDD
SMOOTHED CAPD NORMAL DAILY WEATHER (30 YEAR ENDING MARCH 2012)

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	25	24	18	10	3	0	0	0	0	2	9	19
2	25	24	18	10	3	0	0	0	0	3	10	20
3	26	24	18	9	3	0	0	0	0	3	10	21
4	26	24	18	9	3	0	0	0	0	3	10	21
5	26	24	17	9	3	0	0	0	0	4	11	21
6	27	23	17	8	3	0	0	0	0	4	11	21
7	27	23	17	8	3	0	0	0	0	4	11	22
8	27	23	17	8	3	0	0	0	0	4	12	22
9	27	23	16	8	2	0	0	0	0	4	12	22
10	27	23	16	8	2	0	0	0	0	5	12	23
11	27	23	16	7	2	0	0	0	0	5	13	23
12	27	23	16	7	2	0	0	0	0	5	13	23
13	27	23	15	7	2	0	0	0	0	5	13	23
14	27	23	15	7	2	0	0	0	0	6	14	24
15	27	22	15	7	2	0	0	0	0	6	14	24
16	27	22	14	7	2	0	0	0	1	6	14	24
17	27	22	14	7	2	0	0	0	1	6	15	24
18	27	22	14	7	2	0	0	0	1	6	16	24
19	27	21	13	6	1	0	0	0	1	6	16	25
20	26	21	13	6	1	0	0	0	1	6	16	25
21	26	21	13	6	1	0	0	0	1	6	16	25
22	26	20	13	6	1	0	0	0	1	7	17	25
23	26	20	12	5	1	0	0	0	1	7	17	25
24	26	20	12	5	1	0	0	0	2	7	17	25
25	26	20	12	5	1	0	0	0	2	7	18	25
26	26	19	11	5	1	0	0	0	2	8	18	26
27	26	19	11	4	1	0	0	0	2	8	18	26
28	26	19	11	4	1	0	0	0	2	8	19	26
29	26	19	11	4	1	0	0	0	2	8	19	26
30	26		10	3	1	0	0	0	3	9	20	26
31	25		10		0		0	0		9		26
Calendar Total	817	631	436	203	49	1	0	0	20	178	436	738

Docket 12-00064

ATMOS ENERGY CORPORATION

SETTLEMENT AGREEMENT

ATTACHMENT D

Atmos Energy Corp - Tennessee Distribution System
Docket No. 12-00064
Rate Design

Line No.	Description	Current Monthly Customer chg	Current Commodity Charge/Ccf	Proposed Monthly Customer chg	Proposed Commodity Charge/Ccf
1	Rate Schedule 210/225				
2	210/225 SUMMER	$10.50	$0.1347	13.85	0.1227
3	210/225 WINTER (weather sensitive)	$13.50	$0.1347	16.85	0.1227
4	210/225 SR CIT	$0.00	$0.1347	0.00	0.1227
5					
6					
7	Rate Schedule 211				
8	211 HVAC	$10.50	$0.0711	13.85	0.0719
9					
10	Rate Schedule 220				
11	220 COM/IND GS	$30.00	$0.2073	35.00	0.2332
12	220 TRANSP	$310.00	$0.2073	425.00	0.2332
13					
14					
15	Rate Schedule 221				
16	221 EXPERIMENTAL SGS	$30.00	$0.0996	35.00	0.1134
17					
18	Rate Schedule 230				
19	230 LRG COM/IND/TRANS	$200.00	$0.1831	375.00	0.2036
20	230 TRANSP	$310.00	$0.1831	425.00	0.2036
21					
22					
23	Rate Schedule 240/250/260/292/293				
24	240/250 DEMAND/COMM GS	$310.00		425.00	
25	Block 1 Volumes		$0.1015		0.1141
26	Block 2 Volumes		$0.0672		0.0755
27	Block 3 Volumes		$0.0311		0.0349
28	280 ECONOMIC DEV GS (240/250)	$310.00		425.00	
29	Block 1 Volumes		$0.0761		0.0856
30	Block 2 Volumes		$0.0504		0.0566
31	Block 3 Volumes		$0.0233		0.0262
32	260 - TRANSP (280/250 ECON DEV - OPT GS)	$310.00		425.00	
33	Block 1 Volumes		$0.1015		0.1141
34	Block 2 Volumes		$0.0672		0.0755
35	Block 3 Volumes		$0.0311		0.0566
36	292/293 CNG/LRG TONN HVAC GS	$30.00		35.00	
37	Block 1 Volumes		$0.1015		0.1141
38	Block 2 Volumes		$0.0672		0.0755
39	Block 3 Volumes		$0.0311		0.0349

Docket 12-00064

ATMOS ENERGY CORPORATION

SETTLEMENT AGREEMENT

ATTACHMENT E

T.R.A. No. 1
7th 6th Revised Sheet No. 4
ATMOS ENERGY CORPORATION Canceling 6th 5th Revised Sheet No. 4

RESIDENTIAL GAS SERVICE

Schedule 210: All Service Areas

Availability

Residential service is available within the Company's service area to single private residences, including the separate private units of apartment houses and other multiple dwellings, actually used for residential purposes, which are separately metered.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area.

Customer Charge

A monthly customer charge of ~~$13.50~~ $16.85 for the months of October through April is payable regardless of the usage of gas. I

A customer charge of ~~$10.50~~ $13.85 for the months of May through September is payable regardless of the usage of gas. I

Monthly

All consumption, per Ccf ~~$.1347~~ $.1227 D

Minimum Bill

The minimum net monthly bill shall be the customer charge per month as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

Gas Lights

For all gas light services, the charge for such services shall be based on actual usage through a metered source at this tariff rate. For all unmetered gas light services prior to August 17, 1990 the customer will be billed for twenty (20) Ccf per standard residential gas light. For all unmetered gas light service after August 17, 1990 the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

Issued by: Patricia J. Childers, VP Rates and Regulatory Affairs **Effective Date: Bills Rendered On or After**
Date Issued: **December 1, 2012**

RESIDENTIAL AND SMALL COMMERCIAL/INDUSTRIAL
HEATING AND COOLING SERVICE

Schedule 211: All Service Areas

Availability

This service is available within the Company service area to single private residences, including the separate private units of apartment houses and other multiple dwellings, actually used for residential purposes, which are separately metered and which utilize natural gas for heating and cooling the conditioned space. This schedule is also available within the Company's service area to commercial/industrial customers using less than 5,000 Ccf per year and which utilize natural gas for heating and cooling the conditioned space. Cooling equipment must have a COP greater than 0.7. Any additional gas measured through this single meter will be billed at this rate.

This service is intended to assist in the development of natural gas heating and cooling technologies. This rate is designed to significantly increase energy savings which will improve the economics of the technology. This service will cease when either of the following criteria has been met.

1) One hundred customers have qualified for this service
2) The service expires for new customers ten years after November 15, 1995.

Customers that have qualified for this service prior to the expiration date will continue to receive service under this rate schedule as long as natural gas is utilized for both heating and cooling.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area.

Customer Charge

A monthly customer charge of ~~$10.50~~ $13.85 is payable regardless of the usage of gas. I

Monthly

All consumption, per Ccf ~~$.0711~~ $.0719 I

Minimum Bill

The minimum net monthly bill shall be the customer charge per month as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

COMMERCIAL/INDUSTRIAL GAS SERVICE

Schedule 220: All Service Areas

Availability

This schedule is available within the Company's service area to commercial/industrial customers using less than 135,000 Ccf per year for any purpose at the option of the Company, to the extent gas is available. This schedule is not available to residences, apartment or federal housing projects.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or such higher delivery pressure as agreed upon by customer and Company.

Customer Charge

A monthly customer charge of ~~$30.00~~ $35.00 is payable regardless of the usage of gas. I

Monthly Rate

All Consumption, per Ccf ~~$.2073~~ $.2332 I

Minimum Bill

The minimum net monthly bill shall be the customer charge per meter as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

EXPERIMENTAL SCHOOL GAS SERVICE

Schedule 221: All Service Areas

Availability

This service is available to existing or new state, county, city, and private educational institutions or universities eligible for accreditation by the Southern Association of Secondary Schools and Colleges utilizing natural gas through a single meter for primary heating and cooling of the conditioned space. Any additional gas measured through this single meter will be billed at this rate. Gas cooling equipment must have a coefficient of performance (COP) greater than 0.7.

This service is intended to assist in the development of the natural gas cooling market. This rate is designed to significantly increase energy savings which improves the economics of natural gas cooling. This service is experimental and will cease when any one of the following criteria has been met.

1. Ten (10) schools have qualified for this service.
2. 250,000 Mcf per year of estimated gas consumption has qualified for this service.
3. The experimental service expires on October 1, 2002.

Schools that have qualified for this service prior to October 1, 2002 will continue to receive service under this rate schedule as long as natural gas is utilized for both heating and cooling.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or such higher delivery pressure as agreed upon by customer and Company.

Customer Charge

A monthly customer charge of ~~$30.00~~ $35.00 is payable regardless of the usage of gas. I

Monthly Rate

All Consumption, per Ccf ~~$.0996~~ $.1134 I

Minimum Bill

The minimum net monthly bill shall be the customer charge per meter as described above.

PUBLIC HOUSING AUTHORITY GAS SERVICE

Schedule 225: All Service Areas

Availability

This service is available within the Company's service area to any customer in a housing project using gas primarily for domestic purposes and under the ownership and control of a public housing authority or other governmental agency, which are master metered.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area.

Customer Charge

A monthly customer charge of ~~$13.50~~ $16.85 for the months of October through April is payable regardless of the usage of gas. I

A customer charge of ~~$10.50~~ $13.85 for the months of May through September is payable regardless of the usage of gas. I

Minimum Bill

The minimum net monthly bill shall be the customer charge as described above.

Monthly Rate

All consumption, per Ccf ~~$.1347~~ $.1227 D

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

LARGE COMMERCIAL/INDUSTRIAL GAS SERVICE

Schedule 230: All Service Areas

Availability

This service is available within the Company's service area to any commercial/industrial customers using more than 135,000 Ccf per year for any purpose at the option of the Company, to the extent gas is available.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or at such higher delivery pressure as agreed upon by Customer and Company. Service under this rate schedule may be terminated by either party following twelve (12) months notice to the other party.

Customer Charge

A monthly customer charge of ~~$200.00~~ $375.00 is payable regardless of the usage of gas. I

Monthly Rate

All Consumption, per Ccf ~~$.1831~~ $.2036 I

Minimum Bill

The minimum net monthly bill shall be the customer charge per meter as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

DEMAND/COMMODITY GAS SERVICE

Schedule 240: All Service Areas

Availability

This service is available within the Company's service area to any commercial/industrial customers using at least 270,000 Ccf per year for any purpose at the option of the Company, to the extent gas is available.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or at such higher delivery pressure as agreed upon by Customer and Company. Service under this rate schedule may be terminated by either party following twelve (12) months notice to the other party.

Customer Charge

A monthly Customer Charge of ~~$310.00~~ $425.00 is payable regardless of the usage of gas. I

Monthly Rate

Demand Charge
Per Unit of Billing Demand $1.6283 per Ccf

Commodity Charge

First	20,000	Ccf Per Month	~~$.1015~~ $.1141	I
Next	480,000	Ccf Per Month	~~$.0672~~ $.0755	I
Over	500,000	Ccf Per Month	~~$.0311~~ $.0349	I

Minimum Bill

The minimum net monthly bill shall be the Customer Charge per meter plus the Monthly Demand Charge as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

INTERRUPTIBLE GAS SERVICE

Schedule 250: All Service Areas

Availability

To any commercial or industrial customer using 270,000 Ccf or more per year, or 1,000 Ccf per day during off-peak periods. The Company recommends that the Customer has and maintains adequate standby facilities and an alternate fuel supply in order that gas deliveries hereunder may be interrupted at any time.

Customers that will utilize natural gas during off-peak periods only do not need to meet the volumetric annual requirement (i.e. 270,000 ccf or more per year)for eligibility under this schedule. Examples of customers utilizing natural gas during off-peak periods only would include, but is not limited to the following: asphalt plants, electric generating facilities, grain drying facilities, and farm irrigation systems. The Company recommends an adequate standby facility and alternate fuel supply for off-peak customers served under this schedule.

Deliveries to such customers shall be subject to curtailment at any time. Deliveries to such customers shall be subject to curtailment in whole or in part upon one-half (1/2) hour's notice.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or such higher delivery pressure as agreed upon by customer and Company.

Customer Charge

A monthly customer charge of ~~$310.00~~ $425.00 is payable regardless of the usage of gas. I

Monthly Rate

First	20,000	Ccf used per month	~~$.1015~~ $.1141	I
Next	480,000	Ccf used per month	~~$.0672~~ $.0755	I
Over	500,000	Ccf used per month	~~$.0311~~ $.0349	I

Minimum Bill

The minimum net monthly bill shall be ~~$310.00~~ $425.00 I

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

TRANSPORTATION SERVICE (Continued)

Schedule 260: All Service Areas

(vi) A percentage adjustment for lost and unaccounted for gas shall be made to the volumes of gas received by the Company from the Connecting Pipeline Company for the Customer's account, and the volumes of gas deliverable to the Customer under this rate schedule shall be reduced by such percentage. Such percentage shall be equal to the percent that unaccounted-for gas bore to total sendout as recorded by the Company during its most recent 12 months ended June.

(vii) If the rendition of service to Customer under this rate schedule causes the Company to incur additional charges from the Connecting Pipeline Company, Customer shall reimburse Company for all such charges.

(viii) All volumes transported under the terms of this rate schedule shall be included in the Purchased Gas Adjustment computations and included in the sales volumes of the Purchased Gas Adjustment computations.

(ix) The Customers served under this Rate Schedule shall be required to pay for the cost of, installation of, replacement of, and maintenance of measurement data collection and verification equipment, including applicable income taxes. Customers shall also be required to pay the cost of installation, maintenance and any monthly usage charges associated with dedicated telephone, power or other utilities or energy sources required for the operation of the data collection and verification equipment, including applicable income taxes. Customers shall also be required to provide adequate space in new or existing facilities for the installation of the data collection equipment.

(x) Once a customer elects and has qualified for service under this rate schedule, all services will be provided under the terms and conditions of this rate schedule for a term of no less than 12 months. At any time following the first six months of service under this rate schedule, service may be terminated by either party following at least six months written notice to the other party. After termination of this service, Customer may not re-elect for transportation service for a period of no less than 12 months after termination.

D. Rate

Customer Charge

A monthly customer charge of ~~$310.00~~ $425.00 per meter is payable regardless of the usage of gas. I

Monthly Demand Charge

The Customers eligible to receive service under companion Rate Schedule 240 shall be billed the applicable Monthly Demand Charge.

Monthly Rate

The Customer shall be billed for the quantity of gas delivered under this rate schedule at the monthly rate of the companion rate schedule, plus any applicable taxes or fees.

COGENERATION, COMPRESSED NATURAL GAS, PRIME MOVERS, FUEL CELL SERVICE

Schedule 292: All Service Areas

Purpose

The purpose of providing service under this schedule is to increase utilization of system supplies and system capacity.

Applicability

This schedule is available to the extent gas supply and delivery capacity is available to commercial and industrial customers, existing or new, for use as a single prime fuel source to generate electrical and thermal energy in order to optimize efficiency. This schedule is also available for compressed natural gas for automobile and truck fleets and fuel cell service.

Eligibility

Eligible customers shall include those who are currently connected to the Company's gas main or who will become newly connected. In either case, service will be provided, at the Company's option, through a separate meter.

Character of Service

Natural gas with a heating value of approximately 100,000 Btu per hundred cubic feet, supplied through a single delivery point meter, at the standard equipment utilization pressure, or at such higher delivery pressure as approved by Company.

Rate

Customer Charge

A monthly charge of ~~$30.00~~ $35.00 for each customer regardless of the usage of gas. I

Customer charge for adjacent connected load will not be duplicated, otherwise the facilities charge will be at the customer's regular schedule charge.

Monthly Charge

First	20,000	Ccf used per month	~~$.1015~~ $.1141	I
Next	480,000	Ccf used per month	~~$.0672~~ $.0755	I
Over	500,000	Ccf used per month	~~$.0311~~ $.0349	I

LARGE TONNAGE AIR CONDITIONING GAS SERVICE

Schedule 293: All Service Areas

Purpose

The purpose of providing service under this schedule is to increase utilization of system supplies and system capacity.

Applicability

This schedule is available to the extent gas supply and delivery capacity is available to commercial and industrial customers whose requirements may include high load factor systems that provide chilled water, space conditioning, processing, and/or humidity control. These conditions may be accomplished by the utilization of absorption, gas engine driven or desiccant systems.

Eligibility

Eligible customers shall include those who are currently connected to the Company's gas main or who will become newly connected. In either case, service will be provided, at the Company's option, through a separate meter.

Character of Service

Natural gas with a heating value of approximately 100,000 Btu per hundred cubic feet, supplied through a single delivery point and a single meter, at the standard equipment utilization pressure or at such higher delivery pressure as approved by Company.

Rate

Customer Charge

A monthly charge of ~~$30.00~~ $35.00 for each customer is payable regardless of the usage of gas. I

Customer charge for adjacent connected load will not be duplicated; otherwise the facilities charge will be at the customers regular schedule charge.

Monthly Charge

First	20,000	Ccf used per month	~~$.1015~~ $.1141	I
Next	480,000	Ccf used per month	~~$.0672~~ $.0755	I
Over	500,000	Ccf used per month	~~$.0311~~ $.0349	I

WEATHER NORMALIZATION ADJUSTMENT (WNA) RIDER

Provisions for Adjustment

The base rate per therm/Ccf (100,000 Btu) for gas service set forth in any Rate Schedules utilized by the Tennessee Regulatory Authority in determining normalized test period revenues shall be adjusted by an amount hereinafter described, which amount is referred to as the "Weather Normalization Adjustment." The Weather Normalization Adjustment shall apply to all residential and commercial bills based on meters read during the revenue months of October ~~November~~ through April. C

Definitions

For purpose of this Rider:

"Regulatory Authority" means the Tennessee Regulatory Authority

"Relevant Rate Order" means the final order of the Regulatory Authority in the most recent litigated rate case of the Company fixing the rates of the Company or the most recent final order of the Regulatory Authority specifically prescribing or fixing the factors and procedures to be used in the application of this Rider.

Computation of Weather Normalization Adjustment

The Weather Normalization Adjustment shall be computed to the nearest one-hundredth cent per therm/Ccf by the following formula:

$$WNA_i = R_i \frac{(HSF_i \quad (NDD\text{-}ADD) \quad)}{(BL_i \quad + \quad (HSF_i \times ADD)}$$

Where

i	=	any particular Rate Schedule or billing classification within any such particular Rate Schedule that contains more than one billing classification
WNA_i	=	Weather Normalization Adjustment Factor for the i^{th} rate schedule or classification expressed in cents per therm/Ccf
R_i	=	weighted average base rate of temperature sensitive sales for the i^{th} schedule or classification utilized by the Tennessee Regulatory Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues

WEATHER NORMALIZATION ADJUSTMENT (WNA) RIDER (Continued)

HSF_i = heat sensitive factor for the i^{th} schedule or classification utilized by the Regulatory Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues

NDD = normal billing cycle heating degree days utilized by the Regulatory Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues

ADD = actual billing cycle heating degree days

Bl_i = base load sales for the i^{th} schedule or classification utilized by the Regulatory Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues

Filing with Regulatory Authority

The Company will file as directed by the Regulatory Authority (a) a copy of each computation of the Weather Normalization Adjustment, (b) a schedule showing the effective date of each such Weather Normalization Adjustment, and (c) a schedule showing the factors or values derived from the Relevant Rate Order used in calculating such Weather Normalization Adjustment.

Heat Use/Base Use Factors

	Residential/PA		Commercial	
Town	Base use Ccf	Heat use Ccf/HDD	Base use Ccf	Heat use Ccf/HDD
Union City	~~10.43~~ 7.59	~~.124185~~ .135899	~~112.80~~ 56.84	~~.416839~~ .407379
Columbia Shelbyville Franklin Murfreesboro	~~11.34~~ 9.87	~~.147091~~ .148714	~~112.93~~ 104.91	~~.473009~~ .497239
Maryville Morristown	~~11.39~~ 9.33	~~.122329~~ .119599	~~195.74~~ 114.31	~~.392082~~ .593839
Johnson City Elizabethton Kingsport Greeneville Bristol	~~11.51~~ 8.89	~~.112572~~ .114758	~~125.95~~ 113.15	~~.489418~~ .547136

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, OCTOBER 6, 2014

APPLICATION OF

ATMOS ENERGY CORPORATION

CASE NO. PUE-2013-00124

For an expedited increase in rates

FINAL ORDER

On March 10, 2014, Atmos Energy Corporation ("Atmos" or "Company") filed a completed, amended application with the State Corporation Commission ("Commission") for an expedited increase in rates ("Application") with direct testimony, exhibits, and schedules as prescribed by the Commission's Rules Governing Utility Rate Applications and Annual Informational Filings, 20 VAC 5-201-10 *et seq.* ("Rate Case Rules"). As amended, Atmos proposed to increase its annual revenues by approximately $2,127,600, an overall revenue increase of approximately 7.9%.[1] As provided by 20 VAC 5-201-20 D of the Rate Case Rules, Atmos requested that its increase in rates take effect on an interim basis and subject to refund for services rendered on and after April 9, 2014.[2]

On April 1, 2014, the Commission entered an Order for Notice and Hearing which, among other things, directed the Company to provide notice of its Application and established procedures for receiving comments on the Application and participating in this case. The Commission also set the matter for hearing before a Hearing Examiner; directed the Staff of the Commission ("Staff") to investigate the Application; and found that Atmos had satisfied the requirements for putting its proposed rates in effect on an interim basis on April 9, 2014, subject to refund.

---

[1] Exhibit 3 (Application) at 1.

[2] *Id.*

No respondents filed notices of participation in this case.

On September 4, 2014, the public hearing was convened as scheduled. At the hearing, Atmos and Staff presented a Joint Motion to Accept Stipulation along with a Stipulation resolving all issues in the case ("Stipulation"). Among other things, the Stipulation provided for an annual increase in non-gas base rate revenues of $986,119; established a 9.75% return on equity; provided for Atmos to file a Lead/Lag study as part of its next rate case; provided for Atmos's proposed depreciation rates to be approved as proposed effective October 1, 2013; and addressed the treatment of certain costs as regulatory assets.[3] At the hearing, the Hearing Examiner admitted into the record proof of public notice; the prepared testimony and exhibits of the Company and the Staff; and the Stipulation. No public witnesses appeared at the hearing.

On September 9, 2014, A. Ann Berkebile, Hearing Examiner, filed her report in this case ("Hearing Examiner's Report"). The Hearing Examiner recommended that the Commission accept the Stipulation; grant the Company an increase in annual rates of $986,119; and direct the Company to refund the amounts charged in excess of the rates set forth in the Stipulation. Accordingly, the Hearing Examiner found that because she recommended approval of the Stipulation, that comment on the Hearing Examiner's Report had been waived by the Company and Staff.[4]

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds that the record supports the adoption of the proposed Stipulation, including an increase in annual non-gas base rate revenues of $986,119. In addition, we find that the rates proposed by the Stipulation are designed to afford Atmos an opportunity to earn a reasonable return and are just

[3] Exhibit 1 (Stipulation).

[4] Hearing Examiner's Report at 14.

1410020026

and reasonable. We also direct the Company to refund the amounts charged to customers in excess of the rates we approve in this Final Order.

Specifically, we accept the Stipulation and find as follows:

(1) The use of a test year ending September 30, 2013, is proper in this proceeding.

(2) Atmos's test year operating revenues from Virginia jurisdictional business, after adjustments, were $27,233,900.

(3) Atmos's test year Virginia jurisdictional operating income and adjusted operating income were $2,362,454 and $2,360,785, respectively.

(4) Atmos's adjusted Virginia jurisdictional test year rate base is $37,456,416.

(5) Atmos's current rates produce a return on adjusted rate base of 6.30% and a return on equity of 6.72%.

(6) For purposes of establishing rates in this proceeding, a return on equity of 9.75% is appropriate and is appropriate for any SAVE application that the Company might file prior to any further base rate change. The midpoint of a return on equity range of 9.0% - 10.0% is appropriate for future earnings tests.

(7) The Company may continue to determine its revenue requirement in expedited rate cases based on a 10.0% rate of return on equity.

(8) Atmos requires $986,119 in additional Virginia jurisdictional non-gas base rate revenues to have an opportunity to earn a reasonable return on equity.

(9) The rate design set forth in the Stipulation is reasonable.

(10) The rates produced by the Stipulation are designed to afford Atmos an opportunity to earn a reasonable return and are just and reasonable.

14102002[6]

(11) The revenue allocation proposed by the Stipulation is appropriate for the purpose of this expedited rate case.

(12) The accounting and booking recommendations set forth in the Stipulation are reasonable and should be implemented by Atmos.

Accordingly, IT IS ORDERED THAT:

(1) The findings and recommendations of the Hearing Examiner's Report are hereby adopted.

(2) The Company's Application for an expedited increase in rates is granted as modified herein.

(3) The Company forthwith shall file revised rates and terms and conditions of service conforming to the proposed rates set out in Attachment B to the Stipulation and bearing an effective date of April 9, 2014, effective for service rendered on and after April 9, 2014.

(4) Within ninety (90) days of the entry of this Final Order, the Company shall use the rates and charges approved in Ordering Paragraph (3) to recalculate each bill it rendered that used, in whole or in part, the rates and charges that took effect subject to refund on April 9, 2014. Where application of the rates prescribed in Ordering Paragraph (3) results in a reduced bill, the Company shall refund the difference with interest as set out below.

(5) The refunds with interest directed in Ordering Paragraph (4) for current customers may be made by a credit to the customers' accounts and shown on bills. The bill shall show the refund as a separate item or items. For former customers, the refunds with interest that exceed \$1 shall be made by check, mailed to the last known address of such customers. The Company may set off the credit or refund against any undisputed outstanding balance for the current or

former customer. No set off shall be permitted against any disputed portion of an outstanding balance.

(6) The refund amounts calculated as directed in Ordering Paragraph (4) shall bear interest at a rate for each calendar quarter that shall be the arithmetic mean, to the nearest one-hundredth of one percent, of the "Bank prime loan" values published in the weekly Federal Reserve Statistical Release H. 15 (519), Selected Interest Rates, for the three months of the preceding calendar quarter. The interest shall be computed from the date bills were due to the date of the bill showing the credit to current customers or the date of the refund check mailed to former customers.

(7) Within thirty (30) days of the completion of the refunds required by Ordering Paragraph (4), the Company shall provide to the Commission's Divisions of Utility Accounting and Finance and Energy Regulation a report showing that all refunds have been made pursuant to this Final Order, detailing the costs of the refunds and the accounts charged.

(8) The Company shall bear all costs incurred in effecting the refund ordered herein.

(9) This matter is hereby dismissed.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to: Richard D. Gary, Esquire, Hunton & Williams LLP, Riverfront Plaza, East Tower, 951 East Byrd Street, Richmond, Virginia 23219-4074; and C. Meade Browder, Jr., Senior Assistant Attorney General, Office of the Attorney General, 900 East Main Street, Second Floor, Richmond, Virginia 23219. A copy shall be delivered to the Commission's Office of General Counsel and Divisions of Energy Regulation and Utility Accounting and Finance.

BARRY T. SMITHERMAN, CHAIRMAN
DAVID PORTER, COMMISSIONER
BUDDY GARCIA, COMMISSIONER

LINDIL C. FOWLER, JR., GENERAL COUNSEL
COLIN K. LINEBERRY, DIRECTOR
HEARINGS SECTION

RAILROAD COMMISSION OF TEXAS
OFFICE OF GENERAL COUNSEL

October 3, 2012

TO ALL PARTIES OF RECORD

Re: Gas Utilities Docket No. 10174; Statement of Intent filed by Atmos Energy Corp., Division to Increase Gas Utility Rates in the Unincorporated Areas of its West Texas Division.

SIGNED ORDER

Please find attached a copy of the Final Order signed by the Commissioners in open conference on Tuesday, October 2, 2012, regarding the above-referenced docket.

Sincerely,

Loretta Howard

Loretta Howard
Legal Secretary

Attachment

BEFORE THE
RAILROAD COMMISSION OF TEXAS

STATEMENT OF INTENT FILED BY ATMOS ENERGY CORP., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS SERVED BY THE ATMOS ENERGY CORP., WEST TEXAS DIVISION	**§ § § § § §**	**GAS UTILITIES DOCKET NO. 10174 AND CONSOLIDATED CASES**

FINAL ORDER

Notice of Open Meeting to consider this Order was duly posted with the Secretary of State within the time period provided by law pursuant to TEX. GOV'T CODE ANN. Chapter 551, *et seq*. (Vernon 2008 & Supp. 2011). The Railroad Commission of Texas adopts the following findings of fact and conclusions of law and orders as follows:

FINDINGS OF FACT

1. Atmos Energy Corp., West Texas Division, (Atmos) is a gas utility as that term is defined in the Texas Utility Code and is subject to the jurisdiction of the Railroad Commission of Texas (Commission).

2. On June 6, 2012, Atmos filed a Statement of Intent to change gas utility rates in the unincorporated areas served by the Atmos Energy Corp., West Texas Division. The filing was docketed as GUD No. 10174.

3. Atmos proposed that the increased rates become effective on July 11, 2012.

4. On June 26, 2012, the Commission suspended the implementation of Atmos' proposed rates for up to 150 days.

5. Atmos extended the proposed effective date of the proposed rates, thereby extending the statutory deadline to December 20, 2012.

6. Atmos filed a municipal Statement of Intent with 72 cities (Affected Cities) served by Atmos West Texas on February 7, 2012.

7. Atmos West Texas filed the following Petitions for De Novo Review of the denial of the Statement of Intent by various municipalities that denied that rate request:

a. GUD No. 10175, Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corp., West Texas Division by the Cities of Amherst, Anton, Brownfield, et al. on May 31, 2012. These 44 cities include the following: Amherst, Anton, Bovina, Brownfield, Buffalo Springs, Canyon, Coahoma, Crosbyton, Dimmit, Floydada, Friona, Hale Center, Happy, Hart, Hereford, Lake Tanglewood, Lamesa, Levelland, Littlefield, Lockney, Muleshoe, New Deal, Odessa, Olton, Opdyke West, Palisades, Pampa, Panhandle, Plainview, Quitaque, Ransom Canyon, Sanford, Seminole, Shallowater, Silverton, Slaton, Smyer, Stanton, Sudan, Timbercreek Canyon, Tulia, Turkey, Wilson, and Wolfforth.

b. GUD No. 10178, Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corp., West Texas Division by the Cities of Big Spring, Earth, Edmonson, et al. on June 15, 2012. These 17 cities include the following: Big Spring, Earth, Edmonson, Forsan, Idalou, Kress, Lorenzo, Meadow, Nazareth, O'Donnell, Petersburg, Post, Ralls, Ropesville, Seagraves, Tahoka, and Wellman.

c. GUD No. 10191, Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corp., West Texas Division by the Cities of Abernathy, Amarillo, Channing, et al. on July 11, 2012. These cities include the following: Abernathy, Amarillo, Channing, Dalhart, Fritch, Lubbock, Midland, Springlake, and Vega.

d. GUD No. 10200, Petition of De Novo Review of the Denial of the Statement of Intent filed by Atmos Energy Corporation, West Texas Division by the City of Midland.

8. On March 13, 2012, Atmos filed an *Application of Atmos Energy Corp. to Revise Certain Depreciation Rates* and was docketed as GUD No. 10147.

9. On June 19, 2012, Atmos filed a *Motion to Consolidate* [depreciation issues for Atmos West Texas from GUD No. 10147] *and Motion to Dismiss as to Atmos Pipeline-Texas.*

10. On June 22, 2012, the depreciation issues for Atmos' West Texas Division from GUD No. 10147 were severed into GUD No. 10180.

11. On June 22, 2012, GUD No. 10180 was consolidated into GUD No. 10174.

12. On June 14, 2012, the Amarillo Rate Division Cities, the Lubbock Rate Division City, and Staff of the Railroad Commission of Texas (Staff) intervened in this proceeding.

13. On June 22, 2012, the West Texas Cities Steering Committee intervened in this proceeding. These cities include the following: Amherst, Anton, Big Spring, Bovina, Brownfield, Buffalo Springs, Canyon, Coahoma, Crosbyton, Dimmitt, Earth, Edmonson, Floydada, Frosan, Friona, Hale Center, Happy, Hart, Hereford, Idalou, Kress, Lake

Tanglewood, Lamesa, Levellan, Littlefiedl, Lockney, Lorenzo, Meadow, Muleshoe, Nazareth, New Deal, Odessa, O'Donnell, Olton, Opdyke West, Palisades, Pampa, Panhandle, Petersburg, Plainview, Post, Quitaque, Ralls, Ransom Canyon, Ropesville, Sanford, Seagraves, Seminole, Shallowater, Silverton, Slaton, Smyer, Stanton, Sudan, Tahoka, Timbercreek Canyon, Tulia, Wellman, Wilson, and Wolfforth. On July 26, 2012, the following cities also joined the intervention of West Texas Cities: Abernathy, Midland, Springlake, and Vega.

14. On July 5, 2012, the State of Texas Agencies and Institutions of Higher Education (State Agencies) intervened in this proceeding.

Notice

15. Notice of the filing in this proceeding was provided to all customers within all unincorporated areas served by the West Texas Division by bill insert processing beginning on August 6, 2012 and ending on August 28, 2012. Notice of the filing was also provided by publishing a notice each week for four successive weeks, beginning the week of February 13, 2012 and running through the week of March 5, 2012, in a newpaper having a general circulation in each city affected by the proposed increase. Notice of the filing in this proceeding for the City of Midland was provided by publishing a notice each week for four successive weeks, beginning the week of August 6, 2012 and running through the week of August 27, 2012, in a newspaper having a general circulation in each city affected by the proposed increase.

Test Year

16. The test year in this case was the 12-month period ending September 30, 2011.

Hearing and Partial Settlement

17. The hearing in this matter commenced on September 12, 2012.

18. On September 14, 2012, the following parties filed a partial Settlement Agreement: Atmos West-Texas, Amarillo Rate Division Cities and the Lubbock Rate Division City, West Texas Cities Steering Committee, and Staff. The partial Settlement Agreement is attached to this Final Order as Attachment A.

19. The State was not a signatory to the partial Settlement Agreement.

20. The State declared that it was not opposed to the partial Settlement Agreement.

Books and Records

21. Atmos West Texas established that the utility maintains its books and records in accordance with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts prescribed for Natural Gas Companies.

22. Atmos has established that the utility has fully complied with the books and records requirements of Rule 7.310 and the amounts included therein are therefore subject to the presumption encapsulated in Rule 7.503 that these amounts are reasonable and necessary.

Interim Order

23. The parties filed a motion to limit issues in this proceeding and on August 3, 2012, a ruling was issued which limited the scope of this proceeding to certain issues.

24. The scope of the proceeding limited the following issues from further litigation in the hearing:

   a. Whether Atmos Energy may seek system-wide rates for the Atmos West Texas Division; and
   b. Whether the Commission may set rates on a system-wide basis.

25. The parties were precluded from litigating the question of whether Atmos' proposed rates should be established on a system-wide basis.

26. An Interim Appeal related to preclusion of litigating system wide rates in this docket was filed with the Commission, which was overruled by operation of law.

27. Ample Commission precedent establishes that rates are set for natural gas utilities on a system-wide basis.

28. In GUD No. 9400, *TXU Gas Company Statement of Intent to Change Rates in the Company's Statewide Gas Utility*, the Commission set system-wide rates for the predecessor in interest to the Atmos Mid-Tex Division, of Atmos Energy Corporation.

29. In GUD No. 9488, *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, Darrouzzett, Eden, Farwell, Follett, Groom, Higgins, Junction, Menard, Miami, Mobeetie, Shamrock, Startford, Texhoma, Wheeler, Pain Rock, Cactus, Cnadian, Kermit, Natalia, Somerset, Sonora, and Texline*, Docket Nos. 9488 – 9512, 9520, 9521, & 9526, the Commission set system-wide rates for West Texas Gas, Inc, a utility that owns and operates a natural gas public utility throughout several counties in West Texas.

30. In GUD No. 9902, *Statement of Intent of CenterPoint Energy Corp.*, the Commission set system-wide rates for the Houston Division of CenterPoint Energy. The Houston Division encompasses a large unincorporated area and several municipalities.

Hearing

31. A notice of hearing was issued on July 12, 2012.

32. The hearing on the merits in this matter was conducted from September 12, 2012 through September 21, 2012.

33. The evidentiary record was closed on September 21, 2012.

Overall Revenue Requirements

34. The partial Settlement Agreement sets rates at a level that will result in an overall revenue of $92,600,122.

35. The revenues generated by the rates encompassed in the partial Settlement Agreement will result in a $6,579,919 increase in the company's revenues.

36. The company originally proposed an increase to its overall revenues in the amount of $9,708,267.

37. The partial Settlement Agreement results in a reduction of approximately 32% from the amount originally requested.

38. For purposes of calculating the first interim rate adjustment, the net invested capital amount of $354,663,775 shall be used as the baseline.

39. The base year level of pension-related and other post-employment benefits expenses shall be set as shown on Exhibit D to the attached partial Settlement Agreement and are summarized as follows:

Section 104.059 Benchmarks

Description	**Total**
Shared Services Unit - Pension Account Plan ("PAP")	$378,561
Shared Services Unit - Post-Retirement Medical Plan ("FAS 106")	$316,209
West Texas Division – PAP	$1,368,648
West Texas Division – FAS 106	$2,854,933
West Texas Supplemental Executive Retirement Plan ("SERP")	$151,492

40. Depreciation rates for the West Texas Division direct assets shall be those approved in GUD No. 10041.

41. The SSU Depreciation rates shall be those approved in GUD No. 10170.

42. The federal income tax factor to be used in future interim rate adjustment filings shall be 35%.

43. The *Ad Valorem* tax of $3,659,051 divided by the net invested capital of $354,663,775 for an *Ad Valorem* tax rate of 1.03% shall be applied in future interim rate adjustments.

44. Blueflame is an affiliate of Atmos Energy.

45. The company has established that the expenses related to Blueflame are reasonable and necessary and the price charged to the West Texas Division is not higher than the prices charged by the supplying affiliate to its other affiliates or division or to a non-affiliated person for the same item or class of items.

46. The appropriate rate of return for future interim rate adjustment filings shall be based upon the capital structure, cost of debt, and cost of equity components established by the Railroad Commission in the Final Order issued in GUD No. 10170.

47. The rate design encompassed by the rate elements approved in this Final Order and agreed by the parties in the partial Settlement Agreement is consistent with establishing a cost allocation methodology that evenly distributes costs among all areas served by the West Texas Division.

48. The proposed rates set out below are just and reasonable:

Amarillo Rate Jurisdiction (Incorporated and Unincorporated Areas)

Customer Class	Customer Charge	Consumption Charge
Residential	$13.50	$0.07550 per Ccf
Commercial	$30.00	$0.09794 per Ccf
Industrial	$275.00	$0.11273 per Ccf
Public Authority	$75.00	$0.10638 per Ccf

Lubbock Rate Jurisdiction (Incorporated and Unincorporated Areas)

Customer Class	Customer Charge	Consumption Charge
Residential	$13.50	$0.09175 per Ccf
Commercial	$30.00	$0.09045 per Ccf
Industrial	$275.00	$0.07402 per Ccf
Public Authority	$75.00	$0.12981 per Ccf
State Institution	$75.00	$0.11115 per Ccf

West Texas Cities Rate Jurisdiction (Incorporated Areas)

Customer Class	Customer Charge	Consumption Charge
Residential	$13.50	$0.12614 per Ccf
Commercial	$30.00	$0.09317 per Ccf
Industrial	$275.00	$0.05286 per Ccf
Public Authority	$75.00	$0.08431 per Ccf
State Institution	$75.00	$0.10146 per Ccf

West Texas Cities Rate Jurisdiction (Unincorporated Areas)

Customer Class	Customer Charge	Consumption Charge
Residential	$13.50	$0.17055 per Ccf
Commercial	$30.00	$0.11330 per Ccf
Industrial	$275.00	$0.06091 per Ccf
Public Authority	$75.00	$0.10076 per Ccf
State Institution	$75.00	$0.13551 per Ccf

49. The proposed rate design reduced the number of rates applicable to each class of customers within the Atmos West Texas Division.

50. The proposed rate design represents a phased-in approach that may ultimately result in uniform rates throughout the Atmos West Texas Division.

51. The Miscellaneous Service Charges requested in the company's June 6, 2012 Statement of Intent filing in GUD No. 10174 are just and reasonable.

52. The rates charged within the Atmos West Texas Cities environs is higher than the rates charged within the municipalities served by the West Texas Division.

53. The proposed rates are within 115% of the average of all rates for similar services for all municipalities served by the Atmos West Texas Division.

54. In light of the unique circumstances of this case, and the company's declared intent to pursue system-wide rates, the disparate rate structure is just and reasonable.

55. The attached tariffs and Rider Tax, Rider Franchise Fee Adjustment, Rider Weather Normalization Adjustment and Rider Gas Cost Adjustment, are just and reasonable.

CONCLUSIONS OF LAW

1. Atmos Energy Corp., West Texas Division, (Atmos) is a Gas Utility as defined in TEX. UTIL. CODE ANN. §101.003(7) (Vernon 2007 and Supp. 2011) and §121.001(Vernon 2007) and is therefore subject to the jurisdiction of the Railroad Commission (Commission) of Texas.

2. The Commission has jurisdiction over Atmos and Atmos' *Statement of Intent* under TEX. UTIL. CODE ANN. §§ 102.001, 103.022, 103.054, & 103.055, 104.001, 104.001 and 104.201 (Vernon 2007).

3. Under TEX. UTIL. CODE ANN. §102.001 (Vernon 2007 and Supp. 2011), the Commission has exclusive original jurisdiction over the rates and services of a gas utility that distributes natural gas in areas outside of a municipality and over the rates and services of a gas utility that transmits, transports, delivers, or sells natural gas to a gas utility that distributes gas to the public.

4. This proceeding was conducted in accordance with the requirements of the Gas Utility Regulatory Act (GURA), and the Administrative Procedure Act, TEX. GOV'T CODE ANN. §§ 2001.001 *et seq*. (Vernon 2008 and Supp. 2011) (APA).

5. TEX. UTIL. CODE ANN. §104.107 (Vernon 2007 and Supp. 2011) provides the Commission's authority to suspend the operation of the schedule of proposed rates for 150 days from the date the schedule would otherwise go into effect.

6. The proposed rates constitute a major change as defined by TEX. UTIL. CODE ANN. §104.101 (Vernon 2007 and Supp. 2011).

7. In accordance with TEX. UTIL. CODE ANN. §104.103 (Vernon 2007 and Supp. 2011), 16 TEX. ADMIN. CODE ANN. §§ 7.230 and 7.235, adequate notice was properly provided.

8. In accordance with TEX. UTIL. CODE ANN. §104.102 (Vernon 2007 and Supp. 2011), 16 TEX. ADMIN. CODE ANN. §§ 7.205 and 7.210, Atmos filed its *Statement of Intent* to change gas distribution rates.

9. In this proceeding, Atmos has the burden of proof under TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 and Supp. 2011) to show that the proposed rate changes are just and reasonable.

10. Atmos failed to meet its burden of proof in accordance with the provisions of TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 and Supp. 2011) on the elements of its requested rate increase identified in this order.

11. The revenue, rates, rate design, and service charges proposed by Atmos are not found to be just and reasonable, not unreasonably preferential, prejudicial, or discriminatory, and are not sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. §104.003 (Vernon 2007 and Supp. 2011).

12. The revenue, rates, rate design, and service charges proposed by Atmos, as amended by the Commission and identified in the schedules attached to this order, are just and reasonable, are not unreasonably preferential, prejudicial, or discriminatory, and are

sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. (Vernon 2007 and Supp. 2011).

13. The Commission has assured that the rates, operations, and services established in this docket are just and reasonable to customers and to the utility in accordance with the stated purpose of the Texas Utilities Code, Subtitle A, expressed under TEX. UTIL. CODE ANN. §101.002 (Vernon 2007).

14. The overall revenues as established by the findings of fact and attached schedules are reasonable; fix an overall level of revenues for Atmos that will permit the company a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public over and above its reasonable and necessary operating expenses, as required by TEX. UTIL. CODE ANN. § 104.051 (Vernon 2007 and Supp. 2011); and otherwise comply with Chapter 104 of the Texas Utilities Code Annotated.

15. The revenue, rates, rate design, and service charges proposed will not yield to Atmos more than a fair return on the adjusted value of the invested capital used and useful in rendering service to the public, as required by TEX. UTIL. CODE ANN. § 104.052 (Vernon 2007 and Supp. 2011).

16. The rates established in this docket comport with the requirements of TEX. UTIL. CODE ANN. §104.053 (Vernon 2007 and Supp. 2011) and are based upon the adjusted value of invested capital used and useful, where the adjusted value is a reasonable balance between the original cost, less depreciation, and current cost, less adjustment for present age and condition.

17. The rates established in this case comply with the affiliate transaction standard set out in TEX. UTIL. CODE ANN. § 104.055 (Vernon 2007 and Supp. 2011). Namely, in establishing a gas utility's rates, the regulatory authority may not allow a gas utility's payment to an affiliate for the cost of a service, property, right or other item or for an interest expense to be included as capital cost or an expense related to gas utility service except to the extent that the regulatory authority finds the payment is reasonable and necessary for each item or class of items as determined by the regulatory authority. That finding must include (1) a specific finding of reasonableness and necessity to each class of items allowed; and (2) a finding that the price to the gas utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a nonaffiliated person for the same item or class of items.

18. Section 104.003(a) provides that a rate may not be unreasonably preferential, prejudicial, or discriminatory but must be sufficient, equitable, and consistent in application to each class of consumer. In establishing a gas utility's rates, the Commission "may treat as a single class two or more municipalities that a gas utility serves if the [C]ommission considers that treatment to be appropriate."

19. Rate case expenses for GUD Nos. 10174 and 10195 will be considered by the Commission in accordance with TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 and Supp. 2011), and 16 TEX. ADMIN. CODE §7.5530 (2008), in a separate proceeding.

20. It is reasonable for the Commission to allow Atmos to include a Purchased Gas Adjustment Clause in its rates to provide for the recovery of all of its gas costs, in accordance with 16 TEX. ADMIN. CODE § 7.5519.

21. Atmos is required by 16 TEX. ADMIN. CODE §7.315 to file electronic tariffs incorporating rates consistent with this Order within thirty days of the date of this Order.

22. Atmos has established that the company's books and records conform with 16 TEX. ADMIN. CODE § 7.310 to utilize the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA) prescribed for natural gas companies and Atmos is thus entitled to the presumption that the amounts included therein are reasonable and necessary in accordance with Commission Rule 7.503.

IT IS THEREFORE ORDERED that Atmos' proposed schedule of rates is hereby **DENIED.**

IT IS FURTHER ORDERED that the rates, rate design, and service charges established in the findings of fact and conclusions of law and shown on the attached tariffs for Atmos are **APPROVED.**

IT IS FURTHER ORDERED that the benchmarks established for future interim rate adjustments in these Findings of Fact and attached partial Settlement Agreement are **APPROVED.**

IT IS FURTHER ORDERED that the benchmarks established for the base year level of pension-related and other post-employment benefits expenses are hereby **APPROVED**.

IT IS FURTHER ORDERED that, in accordance with 16 TEX. ADMIN. CODE §7.315, within 30 days of the date this Order is signed, Atmos shall electronically file tariffs and rate schedules with the Gas Services Division. The tariffs shall incorporate rates, rate design, and service charges consistent with this Order, as stated in the findings of fact and conclusions of law and shown on the attached Schedules.

IT IS FURTHER ORDERED that all proposed findings of fact and conclusions of law not specifically adopted in this Order are hereby **DENIED.**

IT IS ALSO ORDERED that all pending motions and requests for relief not previously granted or granted herein are hereby **DENIED.**

This Order will not be final and effective until 20 days after a party is notified of the Commission's order. A party is presumed to have been notified of the Commission's order three days after the date on which the notice is actually mailed. If a timely motion for rehearing is filed by any party at interest, this order shall not become final and effective until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the Commission. Pursuant to TEX. GOV'T CODE ANN. § 2001.146(e), the time allotted for Commission action on a motion for rehearing in this case prior to its being overruled by operation of law, is hereby extended until 90 days from the date the order is served on the parties.

SIGNED this 2nd day of October, 2012.

RAILROAD COMMISSION OF TEXAS

CHAIRMAN BARRY T. SMITHERMAN

COMMISSIONER DAVID PORTER

COMMISSIONER BUDDY GARCIA

ATTEST:

Kathy Way

SECRETARY

SETTLEMENT AGREEMENT BETWEEN ATMOS ENERGY CORPORATION, WEST TEXAS DIVISION, AMARILLO RATE DIVISION CITIES, LUBBOCK RATE DIVISION CITY, WEST TEXAS CITIES STEERING COMMITTEE AND <u>RAILROAD COMMISSION OF TEXAS STAFF</u>

WHEREAS, this settlement agreement (the "Settlement Agreement") is entered into by Atmos Energy Corporation's West Texas Division ("Atmos Energy" or the "Company"); Amarillo Rate Division Cities (consisting of Amarillo, Channing, and Dalhart) and Lubbock Rate Division City (consisting of the city of Lubbock) (collectively referred to as the "Amarillo and Lubbock Cities"); West Texas Cities Steering Committee ("WTX Cities"), which consists of the cities on Exhibit E; and Railroad Commission of Texas Staff ("Staff") (collectively "Signatories");

WHEREAS, Atmos Energy currently has pending before the Railroad Commission of Texas a Statement of Intent to change rates within the unincorporated areas of its West Texas Division and multiple appeals involving municipal ordinances denying Atmos Energy's request to increase rates within the incorporated areas of its West Texas Division, and all pending rate matters related to the Company's West Texas Division have been consolidated into GUD No. 10174; and

WHEREAS, the Amarillo and Lubbock Cities, WTX Cities, State Agencies and Staff sought intervention and were granted party status in GUD No. 10174; and

WHEREAS, Atmos Energy has filed direct and rebuttal testimony and Amarillo and Lubbock Cities, WTX Cities and Staff have each filed intervenor testimony; and

WHEREAS, Amarillo and Lubbock Cities, WTX Cities and Staff have engaged in significant discovery regarding the issues in dispute; and

WHEREAS, the Signatories agree that resolution of this docket by settlement agreement will significantly reduce the amount of reimbursable rate case expenses associated with this docket; and

WHEREAS, although the Signatories represent diverse interests, the Settlement Agreement largely resolves GUD No. 10174 in a manner that the Signatories believe is consistent with the public interest, and in so doing preserves and confirms the Amarillo and Lubbock Cities' right to present their arguments to the Commission, including filing a motion for rehearing on the limited issued identified in Settlement Term No. 3 below and an appeal of the final order in GUD No. 10174 on the limited issue identified in Settlement Term No. 3, below; and

WHEREAS, the Signatories believe that final resolution of all issues in GUD No. 10174 with the exception of the system-wide rate issue contemplated by Settlement Term No. 3 below can best be accomplished by a Commission order approving this Settlement Agreement and the rates, terms and conditions reflected in the tariffs attached to this Settlement Agreement as Exhibit A;

NOW, THEREFORE, in consideration of the mutual agreements and covenants established herein, the Signatories, through their undersigned representatives, agree to and recommend for approval by the Commission the following Settlement Terms as a means of substantially reducing potential rate case expenses by resolving all issues in GUD No. 10174 except for the issue preserved for appeal, pursuant to Settlement Term No. 3, below:

Settlement Terms

1. The Signatories agree to the rates, terms and conditions reflected in the tariffs attached to this Settlement Agreement as Exhibit A. These tariffs should allow Atmos Energy's West Texas Division an additional, system-wide $6.02 million in annual revenues as illustrated in the proof of revenues attached as part of Exhibit B to this Settlement Agreement. The Signatories agree that the $6.02 million revenue increase is a "black box" amount and is not tied to any specific expense in Atmos Energy's West Texas Division's underlying cost of service. Except to the extent that rates under this Agreement are set consistent with a system-wide, cost-of-service methodology the Signatories further agree that the rates, terms and conditions reflected in Exhibit A to this Settlement Agreement comply with the rate-setting requirements of Chapter 104 of the Texas Utilities Code. The gas rates, terms and conditions established by this Settlement Agreement shall, subject to the Commission's approval, be effective for bills rendered on and after October 1, 2012, and should the Commission not approve this Settlement Agreement in time for Atmos Energy to implement rates on October 1, 2012, the Signatories agree that on October 1, 2012, Atmos Energy's existing rates will be established as temporary rates for service on and after that date and such temporary rates will be subject to reconciliation back to October 1, 2012, through a surcharge to give effect to the rates agreed to in this Settlement Agreement; provided that the surcharge period be no longer than a period of sixty days.

2. Exhibit A to this Settlement Agreement does not include the Company's proposed Depreciation Surcharge Rider and Signatories agree that the Depreciation Surcharge Rider should not be approved.

3. The Signatories agree that rates within Atmos Energy's West Texas Division have, under this Settlement Agreement, been established consistent with implementing a system-wide cost of service methodology. Unless the Commission reverses, including as part of an order on rehearing in GUD No. 10174, its decision approving a system-wide cost of service methodology for the West Texas Division, the Signatories also agree that rates for the Company's West Texas Division during the pendency of any appeal shall prospectively be established based on the system-wide cost of providing service within the Company's West Texas Division, which includes the Amarillo, Lubbock and West Texas Cities rate jurisdictions. The Signatories further agree that the Signatories shall propose findings of fact and conclusions of law to be included in the Commission's final order indicating that rates established in GUD No. 10174 were determined consistent with a system-wide cost of service methodology. Notwithstanding anything to the contrary in this Settlement Agreement, the Signatories agree that this Settlement Agreement is predicated upon and affirms that Amarillo and Lubbock Cities have the right to present their arguments to the Commission, including filing a motion for rehearing and an appeal, of the Commission's determination in GUD No. 10174 that rates should be established for the West Texas Division on a system-wide cost of service basis

and its determination that the issue of whether or not Atmos Energy's request to implement such system-wide rates is precluded from litigation.

4. Amarillo and Lubbock Cities agree that any appellate decision related to the system-wide cost of service issues in GUD No. 10174 shall apply on a going-forward basis only and shall not provide a basis to change retroactively the rates established under this Settlement Agreement, or subsequently prevent Atmos Energy from seeking to apply a system-wide cost of service methodology in a future rate proceeding. Amarillo and Lubbock Cities further agree that during the pendency of all appeals related to the Railroad Commission of Texas' system-wide cost of service decision in GUD No. 10174, Amarillo and Lubbock Cities will accept, process and establish rates based on the system-wide cost of service for the Company's West Texas Division.

5. In the event that a final judgment on appeal results in a remand of the system-wide cost of service issue to the Commission, Signatories agree that if, on remand, the Commission determines that rates should be established for the West Texas Division on a basis other than a system-wide cost of service, new rates should be prospectively established through the subsequent filing of a general rate case and such rate case shall be submitted no later than 120 days after the date of the Commission's final order on remand. In order to give effect to any Commission decision on remand, Atmos Energy agrees during the pendency of all appeals and any remand proceeding to maintain its books and records so that they track costs separately for each rate jurisdiction within the West Texas Division.

6. Signatories agree to the following customer charges and consumption charges for customers in Atmos Energy's West Texas Division. These rates are reflected in the rate schedules attached as Exhibit A.

Amarillo Rate Jurisdiction (Incorporated and Unincorporated Areas)

Customer Class	Customer Charge	Consumption Charge
Residential	$13.50	$0.07550 per Ccf
Commercial	$30.00	$0.09794 per Ccf
Industrial	$275.00	$0.11273 per Ccf
Public Authority	$75.00	$0.10638 per Ccf

Lubbock Rate Jurisdiction (Incorporated and Unincorporated Areas)

Customer Class	Customer Charge	Consumption Charge
Residential	$13.50	$0.09175 per Ccf
Commercial	$30.00	$0.09045 per Ccf
Industrial	$275.00	$0.07402 per Ccf
Public Authority	$75.00	$0.12981 per Ccf
State Institution	$75.00	$0.11115 per Ccf

West Texas Cities Rate Jurisdiction (Incorporated Areas)

Customer Class	Customer Charge	Consumption Charge
Residential	$13.50	$0.12614 per Ccf
Commercial	$30.00	$0.09317 per Ccf
Industrial	$275.00	$0.05286 per Ccf
Public Authority	$75.00	$0.08431 per Ccf
State Institution	$75.00	$0.10146 per Ccf

West Texas Cities Rate Jurisdiction (Unincorporated Areas)

Customer Class	Customer Charge	Consumption Charge
Residential	$13.50	$0.17055 per Ccf
Commercial	$30.00	$0.11330 per Ccf
Industrial	$275.00	$0.06091 per Ccf
Public Authority	$75.00	$0.10076 per Ccf
State Institution	$75.00	$0.13551 per Ccf

7. Signatories agree that the Miscellaneous Service Charges requested in the Company's June 6, 2012 Statement of Intent filing in GUD No. 10174 are reasonable and should be approved. Miscellaneous service charge rates are reflected in the rate schedules attached as Exhibit A.

8. Signatories agree that the West Texas Division specific depreciation rates established by the Commission in GUD No. 10041 remain reasonable for use. Signatories further agree that the Shared Services Unit depreciation rates shall be established consistent with the Railroad Commission of Texas' final order in GUD No. 10170 and shall be deemed effective the month that the rates pursuant to this Settlement Agreement are implemented.

9. Signatories agree that the Rider Tax, Rider FF, Rider WNA and Rider GCA, which are attached as Exhibit A, are reasonable and should be approved.

10. Signatories agree that municipalities within the Company's West Texas Division desiring to prospectively utilize a fee-on-fee calculation of municipal franchise fees may execute this option through an amendment to the municipality's franchise agreement with Atmos Energy.

11. To give effect to Section 104.059 of the Gas Utility Regulatory Act, Signatories agree that the base year level of pension-related and other post-employment benefits expenses, as shown on the attached Exhibit D and summarized below, shall be as follows:

Description	Total
Shared Services Unit - Pension Account Plan ("PAP")	$378,561
Shared Services Unit - Post-Retirement Medical Plan ("FAS 106")	$316,209
West Texas Division – PAP	$1,368,648
West Texas Division – FAS 106	$2,854,933
West Texas Supplemental Executive Retirement Plan ("SERP")	$151,492

12. Signatories agree that in an effort to streamline the regulatory review process, Atmos Energy, Amarillo and Lubbock Cities and WTX Cities will work together in good faith to reach agreement on a new Rate Review Mechanism ("Rider RRM") that will establish rates for the West Texas Division based on the system-wide cost of serving the West Texas Division, which includes the Amarillo, Lubbock and West Texas Cities rate jurisdictions. In addition, Amarillo and Lubbock Cities and WTX Cities agree to consider a new RRM that would be consistent with the rate setting methodologies and decisions of the Railroad Commission of Texas' final order in GUD No. 10170. Signatories further agree that the RRM negotiation process shall not be construed as a waiver of Amarillo and Lubbock Cities' and WTX Cities' right to initiate a show cause proceeding or the Company's right to file a Statement of Intent under the provisions of the Texas Utilities Code, nor as a waiver of Amarillo and Lubbock Cities objection to use of a system-wide cost of service for the West Texas Division or of any appeal of the system-wide, rate issue in GUD No. 10174.

13. The Signatories agree that Atmos shall not make any filing in the incorporated areas of the West Texas Division pursuant to Texas Utilities Code § 104.301 so long as the cities and Atmos Energy are in negotiations regarding approval of a new RRM, nor during any period in which rates under an RRM are in effect. The Signatories further agree that any filing in the West Texas Division pursuant to Texas Utilities Code § 104.301 shall use the capital structure and cost of debt and equity established in the Railroad Commission of Texas' final order in GUD No. 10170 and the additional factors identified on the attached Exhibit C.

14. Atmos Energy, Amarillo and Lubbock Cities, and WTX Cities shall seek Commission approval of the parties' reasonable rate case expenses in GUD No. 10195. With regard to rate case expenses approved for recovery in GUD No. 10195, Signatories agree that: (1) Atmos Energy shall forgo recovery of $300,000 of its rate case expenses; (2) the Company's remaining rate case expenses shall be recovered from customers within the incorporated and unincorporated areas; (2) Amarillo and Lubbock Cities' rate case expenses shall be recovered from customers within the Amarillo and Lubbock rate jurisdictions; and, (3) WTX Cities rate case expenses shall be recovered from customers within the incorporated areas of the West Texas Cities rate jurisdiction. Signatories further agree that the parties' reasonable rate case expenses should be recovered by surcharge over a twelve-month period.

15. The Signatories agree to the admission of the pre-filed testimony of the following witnesses, including any confidential portions of such testimony:

Atmos Energy:

- Direct and Rebuttal Testimony of Jeffrey R. Foley
- Direct and Rebuttal Testimony of Thomas H. Petersen
- Direct and Rebuttal Testimony of Barbara W. Myers
- Direct Testimony of Richard Kissinger
- Direct and Rebuttal Testimony of Dane A. Watson
- Direct and Rebuttal Testimony of Daniel Meziere
- Direct and Rebuttal Testimony of Robert B. Hevert
- Direct and Rebuttal Testimony of Gary Smith
- Direct Testimony of Paul Raab
- Rebuttal Testimony Pace McDonald
- Rebuttal Testimony John R. Ellerman
- Rebuttal Testimony of Chris Hutzler
- Rebuttal Testimony of Derek W. Boyd
- Rebuttal Testimony of William L. Brooks

Amarillo and Lubbock Cities:

- Michael L. Brosch
- Steven C. Carver
- Richard Lain
- Robert L. Fratto
- James W. Daniel
- David Parcell

WTX Cities:

- Constance T. Cannady
- Karl J. Nalepa
- Stephen Hill

Staff:

- Direct Testimony of Lynne LeMon
- Direct Testimony of Frank M. Tomicek

16. The Signatories further agree that an offer of proof in GUD No. 10174 may be made by each Signatory with respect to the issue of whether rates should be established for the West Texas Division on a system-wide cost of service basis.

17. The Signatories agree to support and seek Commission approval of this Settlement Agreement.

18. The Signatories agree that neither this Settlement Agreement nor any oral or written statements made during the course of settlement negotiations may be used for any purpose other than as necessary to support the entry by the Commission of an order approving this Settlement Agreement. Signatories further expressly agree that this

Settlement Agreement and any oral or written statements made during the course of settlement negotiations are privileged, inadmissible, and not relevant to prove any issues associated with Atmos Energy's rate filing in GUD No. 10170.

19. The Signatories agree that the terms of the Settlement Agreement are interdependent and indivisible, and that if the Commission enters an order that is inconsistent with this Settlement Agreement, then any Signatory may withdraw without being deemed to have waived any procedural right or to have taken any substantive position on any fact or issue by virtue of that Signatory's entry into the Settlement Agreement or its subsequent withdrawal.

20. The Signatories agree that this Settlement Agreement is binding on each Signatory only for the purpose of settling the issues set forth herein and for no other purposes, and except to the extent the Settlement Agreement governs a Signatory's rights and obligations for future periods, this Settlement Agreement shall not be binding or precedential upon a Signatory outside this proceeding.

21. The Signatories agree that this Settlement Agreement may be executed in multiple counterparts and may be filed with facsimile signatures.

Agreed to this 14th day of September, 2012.

ATMOS ENERGY CORP, WEST TEXAS DIVISION

By: ______________________________
Ann M. Coffin

AMARILLO RATE DIVISION CITIES & LUBBOCK RATE DIVISION CITY

By: ______________________________
Alfred R. Herrera

Settlement Agreement and any oral or written statements made during the course of settlement negotiations are privileged, inadmissible, and not relevant to prove any issues associated with Atmos Energy's rate filing in GUD No. 10170.

19. The Signatories agree that the terms of the Settlement Agreement are interdependent and indivisible, and that if the Commission enters an order that is inconsistent with this Settlement Agreement, then any Signatory may withdraw without being deemed to have waived any procedural right or to have taken any substantive position on any fact or issue by virtue of that Signatory's entry into the Settlement Agreement or its subsequent withdrawal.

20. The Signatories agree that this Settlement Agreement is binding on each Signatory only for the purpose of settling the issues set forth herein and for no other purposes, and except to the extent the Settlement Agreement governs a Signatory's rights and obligations for future periods, this Settlement Agreement shall not be binding or precedential upon a Signatory outside this proceeding.

21. The Signatories agree that this Settlement Agreement may be executed in multiple counterparts and may be filed with facsimile signatures.

Agreed to this 14th day of September, 2012.

ATMOS ENERGY CORP, WEST TEXAS DIVISION

By: ______________________________
Ann M. Coffin

AMARILLO RATE DIVISION CITIES & LUBBOCK RATE DIVISION CITY

By: ______________________________
Alfred R. Herrera

STAFF OF THE RAILROAD COMMISSION OF TEXAS

By: ______________________
John Griffin
Attorney for Staff of the Railroad Commission of Texas

STEERING COMMITTEE OF CITIES SERVED BY ATMOS WEST TEXAS

By: ______________________
Geoffrey M. Gay

STAFF OF THE RAILROAD COMMISSION OF TEXAS

By: ______________________________
John Griffin
Attorney for Staff of the Railroad Commission of Texas

STEERING COMMITTEE OF CITIES SERVED BY ATMOS WEST TEXAS

By: ______________________________
for Geoffrey M. Gay

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	RESIDENTIAL GAS SERVICE	
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION	
EFFECTIVE DATE:	Bills Rendered on and after ~~07/11/2012~~10/01/2012	

Availability

This schedule is applicable to general use by Residential customers for heating, cooking, refrigeration, water heating and other similar type uses. This schedule is not available for service to premises with an alternative supply of natural gas.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ ~~18.00~~ 13.50
Consumption Charge – WTX Cities Incorporated	$ ~~0.05073~~ 0.12614per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.17055 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.07550 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.09175 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

The West Texas Division Weather Normalization Adjustment Rider applies to this schedule.

~~The West Texas Division Rate Review Mechanism (RRM) Adjustment Rider applies to this schedule.~~

~~The West Texas Division Conservation and Energy Efficiency Rider applies to this schedule.~~

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

~~The West Texas Cities Depreciation Surcharge applies to this schedule and to only those cities specifically listed on the Depreciation Surcharge Rider.~~

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**COMMERCIAL GAS SERVICE**
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**
EFFECTIVE DATE:	**Bills Rendered on and after ~~07/11/2012~~10/01/2012**

Availability

This schedule is applicable to Commercial customers, including hospitals and churches, for heating, cooking, refrigeration, water heating and other similar type uses. This schedule is not available for service to premises with an alternative supply of natural gas.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ ~~40.00~~30.00
Consumption Charge – WTX Cities Incorporated	$ ~~0.04805~~0.09317 per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.11330 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.09794 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.09045 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

The West Texas Division Weather Normalization Adjustment Rider applies to this schedule.

~~The West Texas Division Rate Review Mechanism (RRM) Adjustment Rider applies to this schedule.~~

~~The West Texas Division Conservation and Energy Efficiency Rider applies to this schedule.~~

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

~~The West Texas Cities Depreciation Surcharge applies to this schedule and to only those cities specifically listed on the Depreciation Surcharge Rider.~~

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	INDUSTRIAL GAS SERVICE	
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION	
EFFECTIVE DATE:	Bills Rendered on and after ~~07/11/2012~~10/01/2012	

Availability

This schedule is applicable to the sales to any industrial or commercial customer whose predominant use of natural gas is other than space heating, cooking, water heating or other similar type uses. Service under this schedule is available to eligible customers following execution of a contract specifying the maximum hourly load. This schedule is not available for service to premises with an alternative supply of natural gas.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ 275.00
Consumption Charge – WTX Cities Incorporated	$ ~~0.03962~~0.05286 per ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.06091 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.11273 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.07402 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

~~The West Texas Division Rate Review Mechanism (RRM) Adjustment Rider applies to this schedule.~~

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

~~The West Texas Cities Depreciation Surcharge applies to this schedule and to only those cities specifically listed on the Depreciation Surcharge Rider.~~

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	PUBLIC AUTHORITY GAS SERVICE	
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION	
EFFECTIVE DATE:	Bills Rendered on and after ~~07/11/2012~~10/01/2012	

Availability

This schedule is applicable to general use by Public Authority type customers, including public schools, for heating, cooking, refrigeration, water heating and other similar type uses. This schedule is not available for service to premises with an alternative supply of natural gas.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ 75.00
Consumption Charge – WTX Cities Incorporated	$ ~~0.07131~~0.08431 per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.10076 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.10638 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.12981 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

The West Texas Division Weather Normalization Adjustment Rider applies to this schedule.

~~The West Texas Division Rate Review Mechanism (RRM) Adjustment Rider applies to this schedule.~~

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

~~The West Texas Cities Depreciation Surcharge applies to this schedule and to only those cities specifically listed on the Depreciation Surcharge Rider.~~

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**STATE INSTITUTION GAS SERVICE**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on and after ~~07/11/2012~~10/01/2012**	

Availability

This schedule is applicable to gas service to state agencies (as provided in Texas Utilities Code, Section 104.202) including, but not limited to, state college and universities, MHMR schools, agriculture, highway and public safety departments, prisons, and other facilities owned or operated by the State of Texas for the purpose of heating, cooking, refrigeration, water heating and other similar type uses.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ 75.00
Consumption Charge – WTX Cities Incorporated	$ ~~0.07131~~0.10146 per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.13551 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.11115 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

The West Texas Division Weather Normalization Adjustment Rider applies to this schedule.

~~The West Texas Division Rate Review Mechanism (RRM) Adjustment Rider applies to this schedule.~~

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

~~The West Texas Cities Depreciation Surcharge applies to this schedule and to only those cities specifically listed on the Depreciation Surcharge Rider.~~

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**TRANSPORTATION SERVICE**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on or after ~~07/11/2011~~10/01/2012**	

Application
Applicable, in the event that Company has entered into a Transportation Agreement, to a customer directly connected to the Atmos Energy Corp., West Texas Division Distribution System for the transportation of all natural gas supplied by Customer or Customer's agent at one Point of Delivery for use in Customer's facility with an estimated annual usage greater than 100,000 Ccf per meter.

Type of Service
Where service of the type desired by Customer is not already available at the Point of Delivery, additional charges and special contract arrangements between Company and Customer may be required prior to service being furnished.

Monthly Rate
Customer's bill will be calculated by adding the following Customer and Ccf charges to the amounts and quantities due under the riders listed below:

Charge	Amount
Customer Charge per Meter – All Areas in the West Texas Division	$ 275.00 per month
Consumption Charge ~~per Ccf~~ – WTX Cities Incorporated	$ ~~0.03962~~0.05286 per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.06091 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.11273 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.07402 per ccf

Formatted Table

Upstream Transportation Cost Recovery: The customer is responsible for all upstream transportation costs.

~~Rate Review Mechanism: Plus or Minus an amount for rates as calculated in accordance with Rider RRM.~~

Retention Adjustment: Plus a quantity of gas equal to the Company's most recently calculated financial L&U percentage for the twelve months ended September multiplied by the gas received into Atmos Energy Corporation's West Texas Division for transportation to the customer.

Franchise Fee Adjustment: Plus an amount for franchise fees calculated in accordance with Rider FF. Rider FF is only applicable to customers inside the corporate limits of any incorporated municipality.

Tax Adjustment: Plus an amount for tax calculated in accordance with Rider TAX.

Surcharges: Plus an amount for surcharges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**TRANSPORTATION SERVICE**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on or after ~~07/11/2012~~10/01/2012**	

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

Conversions: Units may be converted from Ccf to Mcf or Mmbtu as necessary to comply with the underlying transportation agreement.

Imbalance Fees
All fees charged to Customer under this Rate Schedule will be charged based on the quantities determined under the applicable Transportation Agreement and quantities will not be aggregated for any Customer with multiple Transportation Agreements for the purposes of such fees.

Monthly Imbalance Fees
Customer shall pay Company a monthly imbalance fee at the end of each month as defined in the applicable Transportation Agreement.

Curtailment Overpull Fee
Upon notification by Company of an event of curtailment or interruption of Customer's deliveries, Customer will, for each MMBtu delivered in excess of the stated level of curtailment or interruption, pay Company 200% of the "Index" price reported for the month of delivery in Inside FERC's Gas Market Report under the heading "West Texas Waha".

Replacement Index
In the event the "Index" price reported for the month of delivery in Inside FERC's Gas Market Report under the heading "West Texas Waha" is no longer published, Company will calculate the applicable imbalance fees utilizing a daily price index recognized as authoritative by the natural gas industry and most closely approximating the applicable index.

Agreement
A transportation agreement is required.

Notice
Service hereunder and the rates for services provided are subject to the orders of regulatory bodies having jurisdiction and to the Company's Tariff for Gas Service.

Special Conditions
In order to receive transportation service under this tariff, customer must have the type of meter, instrumentation, and communication required by Company. Customer must pay Company all costs associated with the acquisition and installation of the required equipment.

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**WEST TEXAS DIVISION GAS COST ADJUSTMENT (GCA) RIDER**
APPLICABLE TO:	**ALL SERVICE AREAS IN THE WEST TEXAS DIVISION**
EFFECTIVE DATE:	**Bills Rendered on and after ~~07/11/2012~~10/01/2012**

Application

Gas bills issued under rate schedules to which this Rider applies will include adjustments to reflect decreases or increases in purchased gas costs or taxes. Accumulated Deferred Gas Costs shall also be adjusted for gas cost amounts which are uncollectible. Any such adjustments shall be filed with the appropriate regulatory authority before the beginning of the month in which the adjustment will be applied to bills. The amount of each adjustment shall be computed as follows:

Gas Cost Adjustment (GCA)

The GCA to be applied to each Ccf billed shall be computed as follows and rounded to the nearest $0.01:

$$GCA = (G/S + CF)$$

Where:

1. "G", in dollars, is the expected cost of gas for the expected sales billing units.

2. "S", in Ccf as measured at local atmospheric pressure, is the expected sales billing units to be billed to customers in the respective section of the Company's West Texas Division.

3. "CF", in $/Ccf as measured at local atmospheric pressure, is a correction factor charge per Ccf to adjust for the cumulative monthly differences between the cost of gas purchased by the Company and the amount of gas cost billed the customer plus any gas cost which is uncollectible.

More specifically, CF shall be calculated as follows:

$$CF = (a/b) + (c/b)$$

a = over (under) collection dollar amount for the 12 month period ending September.

b = expected estimated sales volumes for the future 12 month period ending November.

c = net uncollectible gas cost, that is:

(uncollectible gas cost for the previous 12 months ended September) – (subsequently collected gas cost for the previous 12 months ended September)

Once a year, on a 12 months ended September basis, the Company shall review the percentage of lost and unaccounted for gas. If this percentage exceeds 5% of the amount metered in, the correcting account balance will be reduced so that the customer will effectively be charged a maximum of 5% for lost and unaccounted for gas and the Company will absorb the excess.

ATMOS ENERGY CORPORATION **EXHIBIT A**

WEST TEXAS DISTRIBUTION SYSTEM

RATE SCHEDULE:	**WEST TEXAS DIVISION WEATHER NORMALIZATION ADJUSTMENT (WNA) RIDER**
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**
EFFECTIVE DATE:	**Bills Rendered on and after ~~07/11/2012~~10/01/2012**

Provisions for Adjustment

The base rate per Ccf (100,000 Btu) for gas service set forth in any Rate Schedules utilized in all cities in the West Texas Division or their environs for determining normalized winter period revenues shall be adjusted by an amount hereinafter described, which amount is referred to as the "Weather Normalization Adjustment." The Weather Normalization Adjustment shall apply to all temperature sensitive residential, commercial, public authority, and state institution bills based on meters read during the revenue months of October through May.

Computation of Weather Normalization Adjustment

The Weather Normalization Adjustment Factor shall be computed to the nearest one-hundredth cent per Ccf by the following formula:

WNAF i	R i (HSF i (NDD-ADD)) = (BL i + (HSF i x ADD)
Where	
i	= any particular Rate Schedule or billing classification within any such particular Rate Schedule that contains more than one billing classification
WNAF i	= Weather Normalization Adjustment Factor for the i^{th} rate schedule or classification expressed in cents per Ccf
R i	= base rate of temperature sensitive sales for the i^{th} schedule or classification utilized
HSF i	= heat sensitive factor for the i^{th} schedule or classification divided by the average bill count in that class
NDD i	= billing cycle normal heating degree days
ADD i	= billing cycle actual heating degree days
BL i	= base load sales for the i^{th} schedule or Classification divided by the average bill count in that class

The Weather Normalization Adjustment for the j^{th} customer in i^{th} rate schedule is computed as:

WNA i	WNAF i x qii Where qii is the relevant sales quantity for the j^{th} Customer in i^{th} rate schedule

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RIDER:	FF – FRANCHISE FEE ADJUSTMENT
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION
EFFECTIVE DATE:	Bills Rendered on and after ~~07/11/2012~~10/01/2012

Application

Applicable to Customers inside the corporate limits of an incorporated municipality that imposes a municipal franchise fee upon Company for the Gas Service provided to Customer. Franchise Fees to be assessed solely to customers within the municipal limits. This does not apply to Environs customers.

Monthly Adjustment

Company will adjust Customer's bill each month in an amount equal to the municipal franchise fees payable for the Gas Service provided to Customer by Company. Municipal franchise fees are determined by each municipality's franchise ordinance. Each municipality's franchise ordinance will specify the percentage and applicability of franchise fees.

From time to time, Company will make further adjustments to Customer's bill to account for any over- or under-recovery of municipal franchise fees by Company.

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RIDER:	TAX – TAX ADJUSTMENT	
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION	
EFFECTIVE DATE:	Bills Rendered on and after ~~07/11/2012~~10/01/2012	

Application

Applicable to Customers taking service under Residential, Commercial, Industrial, ~~and~~ Public Authority, and State Institution customers to the extent of state gross receipts taxes only.

Each monthly bill shall be adjusted for state gross receipts taxes imposed by Sections 182-021 - 182-025 of the Texas Tax Code.

Each monthly bill shall also be adjusted by an amount equivalent to the amount of all applicable taxes and any other governmental impositions, rentals, fees, or charges (except state, county, city, and special district ad valorem taxes and taxes on net income) levied, assessed, or imposed upon or allocated to Company with respect to the Gas Service provided to Customer by Company, and any associated facilities involved in the performance of such Gas Service. Each monthly bill shall also be adjusted by an amount equivalent to the proportionate part of any increase or decrease of any tax and any other governmental imposition, rental, fee, or charge (except state, county, city, and special district ad valorem taxes and taxes on net income) levied, assessed, or imposed subsequent to the effective date of this tariff, upon or allocated to Company's operations, by any new or amended law, ordinance, or contract.

ATMOS ENERGY CORPORATION
WEST TEXAS DIVISION

EXHIBIT A

RATE SCHEDULE:	OTHER SERVICE CHARGES
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION
EFFECTIVE DATE:	Bills Rendered on and after ~~07/11/2012~~10/01/2012

The service charges on this tariff will be applied in accordance with Atmos Energy's Quality of Service rules and Commission rule 7.45.

DURING BUSINESS HOURS:

These charges apply to services initiated between 8am and 5pm, Monday through Friday.

Charge	Amount
Turn On New Service With Meter Set	$ 45.00
Turn On Service (shut-In test required)	$ 37.00
Turn On Service (meter read only required)	$ 21.00
Miscellaneous Service Charge Calls	$ 10.00
Reconnect Delinquent Service or Service Temporarily Off at Customer's Request	$ 47.00
Return Check Fee	$ 25.00
Tampering Fee	$ 150.00

AFTER BUSINESS HOURS:

These charges apply to services initiated between 5pm and 8am, Monday through Friday, and all day Saturday and Sunday.

Charge	Amount
Turn On New Service With Meter Set	$ 67.50
Turn On Service (shut-In test required)	$ 55.50
Turn On Service (meter read only required)	$ 31.50
Miscellaneous Service Charge Calls	$ 15.00
Reconnect Delinquent Service or Service Temporarily Off at Customer's Request	$ 70.50

ATMOS ENERGY CORPORATION
WEST TEXAS DIVISION

EXHIBIT A

RATE SCHEDULE:	OTHER SERVICE CHARGES
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION
EFFECTIVE DATE:	Bills Rendered on and after ~~07/11/2012~~10/01/2012

Tampering Fee	$ 150.00

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	RESIDENTIAL GAS SERVICE	
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION	
EFFECTIVE DATE:	Bills Rendered on and after 10/01/2012	

Availability

This schedule is applicable to general use by Residential customers for heating, cooking, refrigeration, water heating and other similar type uses. This schedule is not available for service to premises with an alternative supply of natural gas.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ 13.50
Consumption Charge – WTX Cities Incorporated	$ 0.12614 per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.17055 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.07550 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.09175 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

The West Texas Division Weather Normalization Adjustment Rider applies to this schedule.

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**COMMERCIAL GAS SERVICE**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on and after 10/01/2012**	

Availability

This schedule is applicable to Commercial customers, including hospitals and churches, for heating, cooking, refrigeration, water heating and other similar type uses. This schedule is not available for service to premises with an alternative supply of natural gas.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ 30.00
Consumption Charge – WTX Cities Incorporated	$ 0.09317 per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.11330 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.09794 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.09045 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

The West Texas Division Weather Normalization Adjustment Rider applies to this schedule.

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**INDUSTRIAL GAS SERVICE**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on and after 10/01/2012**	

Availability

This schedule is applicable to the sales to any industrial or commercial customer whose predominant use of natural gas is other than space heating, cooking, water heating or other similar type uses. Service under this schedule is available to eligible customers following execution of a contract specifying the maximum hourly load. This schedule is not available for service to premises with an alternative supply of natural gas.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ 275.00
Consumption Charge – WTX Cities Incorporated	$ 0.05286 per ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.06091 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.11273 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.07402 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**PUBLIC AUTHORITY GAS SERVICE**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on and after 10/01/2012**	

Availability

This schedule is applicable to general use by Public Authority type customers, including public schools, for heating, cooking, refrigeration, water heating and other similar type uses. This schedule is not available for service to premises with an alternative supply of natural gas.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ 75.00
Consumption Charge – WTX Cities Incorporated	$ 0.08431 per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.10076 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.10638 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.12981 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

The West Texas Division Weather Normalization Adjustment Rider applies to this schedule.

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**STATE INSTITUTION GAS SERVICE**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on and after 10/01/2012**	

Availability

This schedule is applicable to gas service to state agencies (as provided in Texas Utilities Code, Section 104.202) including, but not limited to, state college and universities, MHMR schools, agriculture, highway and public safety departments, prisons, and other facilities owned or operated by the State of Texas for the purpose of heating, cooking, refrigeration, water heating and other similar type uses.

Monthly Rate

Charge	Amount
Customer Charge – All Areas In The West Texas Division	$ 75.00
Consumption Charge – WTX Cities Incorporated	$ 0.10146 per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.13551 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.11115 per ccf

The West Texas Division Gas Cost Adjustment Rider applies to this schedule.

The West Texas Division Weather Normalization Adjustment Rider applies to this schedule.

The West Texas Division Rider TAX applies to this schedule.

The West Texas Division Rider FF applies to this schedule.

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**TRANSPORTATION SERVICE**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on or after 10/01/2012**	

Application
Applicable, in the event that Company has entered into a Transportation Agreement, to a customer directly connected to the Atmos Energy Corp., West Texas Division Distribution System for the transportation of all natural gas supplied by Customer or Customer's agent at one Point of Delivery for use in Customer's facility with an estimated annual usage greater than 100,000 Ccf per meter.

Type of Service
Where service of the type desired by Customer is not already available at the Point of Delivery, additional charges and special contract arrangements between Company and Customer may be required prior to service being furnished.

Monthly Rate
Customer's bill will be calculated by adding the following Customer and Ccf charges to the amounts and quantities due under the riders listed below:

Charge	Amount
Customer Charge per Meter – All Areas in the West Texas Division	$ 275.00 per month
Consumption Charge - WTX Cities Incorporated	$ 0.05286 per Ccf
Consumption Charge – WTX Cities Unincorporated	$ 0.06091 per ccf
Consumption Charge – Amarillo Incorporated and Unincorporated	$ 0.11273 per ccf
Consumption Charge – Lubbock Incorporated and Unincorporated	$ 0.07402 per ccf

Upstream Transportation Cost Recovery: The customer is responsible for all upstream transportation costs.

Retention Adjustment: Plus a quantity of gas equal to the Company's most recently calculated financial L&U percentage for the twelve months ended September multiplied by the gas received into Atmos Energy Corporation's West Texas Division for transportation to the customer.

Franchise Fee Adjustment: Plus an amount for franchise fees calculated in accordance with Rider FF. Rider FF is only applicable to customers inside the corporate limits of any incorporated municipality.

Tax Adjustment: Plus an amount for tax calculated in accordance with Rider TAX.

Surcharges: Plus an amount for surcharges calculated in accordance with the applicable rider(s).

Miscellaneous Charges: Plus an amount for miscellaneous charges calculated in accordance with the applicable rider(s).

RATE SCHEDULE:	**TRANSPORTATION SERVICE**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on or after 10/01/2012**	

Conversions: Units may be converted from Ccf to Mcf or Mmbtu as necessary to comply with the underlying transportation agreement.

Imbalance Fees
All fees charged to Customer under this Rate Schedule will be charged based on the quantities determined under the applicable Transportation Agreement and quantities will not be aggregated for any Customer with multiple Transportation Agreements for the purposes of such fees.

Monthly Imbalance Fees
Customer shall pay Company a monthly imbalance fee at the end of each month as defined in the applicable Transportation Agreement,

Curtailment Overpull Fee
Upon notification by Company of an event of curtailment or interruption of Customer's deliveries, Customer will, for each MMBtu delivered in excess of the stated level of curtailment or interruption, pay Company 200% of the "Index" price reported for the month of delivery in Inside FERC's Gas Market Report under the heading "West Texas Waha".

Replacement Index
In the event the "Index" price reported for the month of delivery in Inside FERC's Gas Market Report under the heading "West Texas Waha" is no longer published, Company will calculate the applicable imbalance fees utilizing a daily price index recognized as authoritative by the natural gas industry and most closely approximating the applicable index.

Agreement
A transportation agreement is required.

Notice
Service hereunder and the rates for services provided are subject to the orders of regulatory bodies having jurisdiction and to the Company's Tariff for Gas Service.

Special Conditions
In order to receive transportation service under this tariff, customer must have the type of meter, instrumentation, and communication required by Company. Customer must pay Company all costs associated with the acquisition and installation of the required equipment.

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RATE SCHEDULE:	**WEST TEXAS DIVISION GAS COST ADJUSTMENT (GCA) RIDER**	
APPLICABLE TO:	**ALL SERVICE AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on and after 10/01/2012**	

<u>Application</u>

Gas bills issued under rate schedules to which this Rider applies will include adjustments to reflect decreases or increases in purchased gas costs or taxes. Accumulated Deferred Gas Costs shall also be adjusted for gas cost amounts which are uncollectible. Any such adjustments shall be filed with the appropriate regulatory authority before the beginning of the month in which the adjustment will be applied to bills. The amount of each adjustment shall be computed as follows:

<u>Gas Cost Adjustment (GCA)</u>

The GCA to be applied to each Ccf billed shall be computed as follows and rounded to the nearest $0.01:

GCA= (G/S + CF)

Where:
1. "G", in dollars, is the expected cost of gas for the expected sales billing units.

2. "S", in Ccf as measured at local atmospheric pressure, is the expected sales billing units to be billed to customers in the respective section of the Company's West Texas Division.

3. "CF", in $/Ccf as measured at local atmospheric pressure, is a correction factor charge per Ccf to adjust for the cumulative monthly differences between the cost of gas purchased by the Company and the amount of gas cost billed the customer plus any gas cost which is uncollectible.

More specifically, CF shall be calculated as follows:

CF = (a/b) + (c/b)

a = over (under) collection dollar amount for the 12 month period ending September.

b = expected estimated sales volumes for the future 12 month period ending November.

c = net uncollectible gas cost, that is:

(uncollectible gas cost for the previous 12 months ended September) – (subsequently collected gas cost for the previous 12 months ended September)

Once a year, on a 12 months ended September basis, the Company shall review the percentage of lost and unaccounted for gas. If this percentage exceeds 5% of the amount metered in, the correcting account balance will be reduced so that the customer will effectively be charged a maximum of 5% for lost and unaccounted for gas and the Company will absorb the excess.

ATMOS ENERGY CORPORATION **EXHIBIT A**

WEST TEXAS DISTRIBUTION SYSTEM

RATE SCHEDULE:	**WEST TEXAS DIVISION WEATHER NORMALIZATION ADJUSTMENT (WNA) RIDER**	
APPLICABLE TO:	**ALL AREAS IN THE WEST TEXAS DIVISION**	
EFFECTIVE DATE:	**Bills Rendered on and after 10/01/2012**	

<u>Provisions for Adjustment</u>

The base rate per Ccf (100,000 Btu) for gas service set forth in any Rate Schedules utilized in all cities in the West Texas Division or their environs for determining normalized winter period revenues shall be adjusted by an amount hereinafter described, which amount is referred to as the "Weather Normalization Adjustment." The Weather Normalization Adjustment shall apply to all temperature sensitive residential, commercial, public authority, and state institution bills based on meters read during the revenue months of October through May.

<u>Computation of Weather Normalization Adjustment</u>

The Weather Normalization Adjustment Factor shall be computed to the nearest one-hundredth cent per Ccf by the following formula:

WNAF i	R i = (HSF i (NDD-ADD)) / (BL i + (HSF i x ADD))
Where	
i	= any particular Rate Schedule or billing classification within any such particular Rate Schedule that contains more than one billing classification
WNAF i	= Weather Normalization Adjustment Factor for the i^{th} rate schedule or classification expressed in cents per Ccf
R i	= base rate of temperature sensitive sales for the i^{th} schedule or classification utilized
HSF i	= heat sensitive factor for the i^{th} schedule or classification divided by the average bill count in that class
NDD i	= billing cycle normal heating degree days
ADD i	= billing cycle actual heating degree days
BL i	= base load sales for the i^{th} schedule or Classification divided by the average bill count in that class

The Weather Normalization Adjustment for the j^{th} customer in i^{th} rate schedule is computed as:

WNA i	WNAF i x qii Where qii is the relevant sales quantity for the j^{th} Customer in i^{th} rate schedule

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RIDER:	FF – FRANCHISE FEE ADJUSTMENT	
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION	
EFFECTIVE DATE:	Bills Rendered on and after 10/01/2012	

Application

Applicable to Customers inside the corporate limits of an incorporated municipality that imposes a municipal franchise fee upon Company for the Gas Service provided to Customer. Franchise Fees to be assessed solely to customers within the municipal limits. This does not apply to Environs customers.

Monthly Adjustment

Company will adjust Customer's bill each month in an amount equal to the municipal franchise fees payable for the Gas Service provided to Customer by Company. Municipal franchise fees are determined by each municipality's franchise ordinance. Each municipality's franchise ordinance will specify the percentage and applicability of franchise fees.

From time to time, Company will make further adjustments to Customer's bill to account for any over- or under-recovery of municipal franchise fees by Company.

WEST TEXAS DIVISION
ATMOS ENERGY CORPORATION

EXHIBIT A

RIDER:	TAX – TAX ADJUSTMENT	
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION	
EFFECTIVE DATE:	Bills Rendered on and after 10/01/2012	

Application

Applicable to Customers taking service under Residential, Commercial, Industrial, Public Authority, and State Institution customers to the extent of state gross receipts taxes only.

Each monthly bill shall be adjusted for state gross receipts taxes imposed by Sections 182-021 - 182-025 of the Texas Tax Code.

Each monthly bill shall also be adjusted by an amount equivalent to the amount of all applicable taxes and any other governmental impositions, rentals, fees, or charges (except state, county, city, and special district ad valorem taxes and taxes on net income) levied, assessed, or imposed upon or allocated to Company with respect to the Gas Service provided to Customer by Company, and any associated facilities involved in the performance of such Gas Service. Each monthly bill shall also be adjusted by an amount equivalent to the proportionate part of any increase or decrease of any tax and any other governmental imposition, rental, fee, or charge (except state, county, city, and special district ad valorem taxes and taxes on net income) levied, assessed, or imposed subsequent to the effective date of this tariff, upon or allocated to Company's operations, by any new or amended law, ordinance, or contract.

ATMOS ENERGY CORPORATION
WEST TEXAS DIVISION

EXHIBIT A

RATE SCHEDULE:	OTHER SERVICE CHARGES	
APPLICABLE TO:	ALL AREAS IN THE WEST TEXAS DIVISION	
EFFECTIVE DATE:	Bills Rendered on and after 10/01/2012	

The service charges on this tariff will be applied in accordance with Atmos Energy's Quality of Service rules and Commission rule 7.45.

DURING BUSINESS HOURS:

These charges apply to services initiated between 8am and 5pm, Monday through Friday.

Charge	Amount
Turn On New Service With Meter Set	$ 45.00
Turn On Service (shut-In test required)	$ 37.00
Turn On Service (meter read only required)	$ 21.00
Miscellaneous Service Charge Calls	$ 10.00
Reconnect Delinquent Service or Service Temporarily Off at Customer's Request	$ 47.00
Return Check Fee	$ 25.00
Tampering Fee	$ 150.00

AFTER BUSINESS HOURS:

These charges apply to services initiated between 5pm and 8am, Monday through Friday, and all day Saturday and Sunday.

Charge	Amount
Turn On New Service With Meter Set	$ 67.50
Turn On Service (shut-In test required)	$ 55.50
Turn On Service (meter read only required)	$ 31.50
Miscellaneous Service Charge Calls	$ 15.00
Reconnect Delinquent Service or Service Temporarily Off at Customer's Request	$ 70.50
Tampering Fee	$ 150.00

File Date: June 13, 2012

EXHIBIT B

ATMOS ENERGY CORPORATION
WEST TEXAS SYSTEM STATEMENT OF INTENT GUD 10174
SUMMARY PROOF OF REVENUE AT CURRENT RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	West Texas ICL	West Texas OCL	Amarillo ICL	Amarillo OCL	Lubbock ICL	Lubbock OCL	Total	Reference
	(a)	(b)	(c)	(d)	(e)	(f)		(g)	(h)
	Residential								
1	Rate Characteristics:								
2	Customer Charge	$7.50	$13.50	$8.21	$13.50	$7.86	$13.50		Tariff- Rates
3									
4									
5	Consumption Charge ($/Ccf)								
6	All Consumption	$0.27514	$0.17055	$0.12862	$0.04562	$0.17913	$0.08395		Tariff- Rates
7									
8	Billing Units:								
9	Bills	1,478,085	151,820	783,776	28,396	746,485	54,205	3,242,768	Billing Determinants Study
10	Total Ccf	72,432,202	8,404,294	48,024,471	1,943,294	36,633,617	3,434,380	170,872,260	Billing Determinants Study
11		93.8%							
12	Present Revenue:								
13	Customer Charge	$ 11,085,640	$ 2,049,568	$ 6,434,802	$ 383,350	$ 5,867,373	$ 731,771	$ 26,552,504	Ln. 2 times Ln. 9
14	Consumption Charge	19,928,996	1,433,352	6,176,907	88,653	6,562,180	288,316	$ 34,478,405	Ln. 6 times Ln. 10
15	Base Revenue	$ 31,014,636	$ 3,482,920	$ 12,611,710	$ 472,003	$ 12,429,553	$ 1,020,087	$ 61,030,909	Sum of Line 13 through Ln. 14
16	Revenue Related Franchise Fees Taxes Related to Margin	1,316,478		535,329		527,597		2,379,404	
17	Revenue Related State Taxes Related to Margin	607,614		247,078		243,510		1,098,202	
18	Margin Net of Tax	29,090,544	3,482,920	11,829,302	472,003	11,658,446	1,020,087	57,553,302	
19	**Commercial**	0.045254502							
20	Rate Characteristics:								
21	Customer Charge	$14.50	$30.00	$15.52	$30.00	$15.59	$27.00		Tariff- Rates
22									
23									
24	Consumption Charge ($/Ccf)								
25	All Consumption	$0.18484	$0.11330	$0.12617	$0.04817	$0.13767	$0.08431		Tariff- Rates
26									
27	Billing Units:								
28	Bills	122,916	20,342	69,398	2,183	67,524	3,657	286,020	Billing Determinants Study
29	Total Ccf	25,133,313	6,099,189	20,322,118	801,015	15,608,146	601,423	68,565,204	Billing Determinants Study
30									
31	Present Revenue:								
32	Customer Charge	$ 1,782,283	$ 610,255	$ 1,077,050	$ 65,493	$ 1,052,700	$ 98,751	$ 4,686,531	Ln. 21 times Ln. 28
33	Consumption Charge	4,645,642	691,038	2,564,042	38,585	2,148,773	50,706	$ 10,138,786	Ln. 25 times Ln. 29
34	Base Revenue	$ 6,427,924	$ 1,301,293	$ 3,641,092	$ 104,078	$ 3,201,473	$ 149,457	$ 14,825,317	Sum of Line 32 through Ln. 33
35	Revenue Related Franchise Fees Taxes Related to Margin	272,846		154,553		135,893		563,292	
36	Revenue Related State Taxes Related to Margin	125,931		71,333		62,721		259,985	
37	Margin Net of Tax	6,029,147	1,301,293	3,415,205	104,078	3,002,860	149,457	14,002,040	

File Date: June 13, 2012

ATMOS ENERGY CORPORATION
WEST TEXAS SYSTEM STATEMENT OF INTENT GUD 10174
SUMMARY PROOF OF REVENUE AT CURRENT RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

EXHIBIT B

Line No.	Description (a)	West Texas ICL (b)	West Texas OCL (c)	Amarillo ICL (d)	Amarillo OCL (e)	Lubbock ICL (f)	Lubbock OCL	Total (g)	Reference (h)
38	**Industrial**								
39	Rate Characteristics:								
40	Customer Charge	$110.00	$275.00	$58.23	$100.00	$94.57	$220.00		Tariff- Rates
41									
42	Consumption Charge ($/Ccf)								
43	0-1000 Ccf	$0.12859	$0.06091	$0.11982	$0.09088	$0.12573	$0.07152		Tariff- Rates
44	Over 1000 Ccf	$0.10277	$0.06091	$0.11982	$0.09088	$0.10350	$0.07152		Tariff- Rates
45									
46	Billing Units:								
47	Bills	917	1,382	271	12	586	48	3,216	Billing Determinants Study
48	Total Ccf	3,432,031	3,839,094	2,677,990	4,795	2,584,863	164,534	12,703,307	Billing Determinants Study
49	0-1000 Ccf	336,602	604,064	158,372	2,462	263,418	32,762	1,397,680	Billing Determinants Study
50	Over 1000 Ccf	3,095,429	3,235,030	2,519,618	2,333	2,321,445	131,773	11,305,627	Billing Determinants Study
51									
52	Present Revenue:								
53	Customer Charge	$ 100,870	$ 380,050	$ 15,780	$ 1,200	$ 55,418	$ 10,560	$ 563,878	Ln. 40 times Ln. 47
54	Consumption Charge								
55	0-1000 Ccf	43,284	36,794	18,976	224	33,119	2,343	$ 134,740	Ln. 43 times Ln. 49
56	Over 1000 Ccf	318,117	197,046	301,901	212	240,270	9,424	$ 1,066,969	Ln. 44 times Ln. 50
57	Base Revenue	$ 462,271	$ 613,889	$ 336,657	$ 1,636	$ 328,807	$ 22,328	$ 1,765,588	Sum of Line 55 through Ln. 56
58	Revenue Related Franchise Fees Taxes Related to Margin	19,622		14,290		13,957		47,869	
59	Revenue Related State Taxes Related to Margin	9,056		6,596		6,442		22,094	
60	Margin Net of Tax	433,592	613,889	315,772	1,636	308,408	22,328	1,695,625	
61	**Public Authority**								
62	Rate Characteristics:								
63	Customer Charge	$55.00	$81.00	$39.44	$45.00	$65.38	$100.00		Tariff- Rates
64									
65									
66	Consumption Charge ($/Ccf)								
67	All Consumption	$0.12786	$0.08968	$0.11798	$0.09197	$0.12602	$0.09612		Tariff- Rates
68									
69	Billing Units:								
70	Bills	16,284	1,172	2,401	173	1,566	169	21,765	Billing Determinants Study
71	Total Ccf	10,705,276	635,070	2,739,839	1,454,389	1,433,942	321,334	17,289,850	Billing Determinants Study
72									
73	Present Revenue:								
74	Customer Charge	$ 895,640	$ 94,955	$ 94,680	$ 7,785	$ 102,360	$ 16,913	$ 1,212,333	Ln. 63 times Ln. 70
75	Consumption Charge	1,368,777	56,953	323,246	133,760	180,705	30,887	$ 2,094,328	Ln. 67 times Ln. 71
76	Base Revenue	$ 2,264,417	$ 151,908	$ 417,926	$ 141,545	$ 283,065	$ 47,799	$ 3,306,661	Sum of Line 74 through Ln. 75
77	Revenue Related Franchise Fees Taxes Related to Margin	96,118		17,740		12,015		125,873	
78	Revenue Related State Taxes Related to Margin	44,363		8,188		5,546		58,096	
79	Margin Net of Tax	2,123,937	151,908	391,999	141,545	265,505	47,799	3,122,692	

File Date: June 13, 2012

EXHIBIT B

ATMOS ENERGY CORPORATION
WEST TEXAS SYSTEM STATEMENT OF INTENT GUD 10174
SUMMARY PROOF OF REVENUE AT CURRENT RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description (a)	West Texas ICL (b)	West Texas OCL (c)	Amarillo ICL (d)	Amarillo OCL (e)	Lubbock ICL (f)	Lubbock OCL	Total (g)	Reference (h)
80	**State**								
81	<u>Rate Characteristics:</u>								
82	Customer Charge	$61.50	$102.00			$60.65	$95.00		Tariff- Rates
83									
84									
85	Consumption Charge ($/Ccf)								
86	All Consumption	$0.13806	$0.05733			$0.11806	$0.07634		Tariff- Rates
87									
88	<u>Billing Units:</u>								
89	Bills	952	150			488	186	1,777	Billing Determinants Study
90	Total Ccf	588,133	51,825			468,367	357,774	1,466,099	Billing Determinants Study
91									
92	<u>Present Revenue:</u>								
93	Customer Charge	$ 58,557	$ 15,307			$ 29,627	$ 17,698	$ 121,189	Ln. 82 times Ln. 89
94	Consumption Charge	81,198	2,971			55,295	27,312	$ 166,777	Ln. 86 times Ln. 90
95	Base Revenue	$ 139,755	$ 18,278			$ 84,923	$ 45,010	$ 287,965	Sum of Line 93 through Ln. 94
96	Revenue Related Franchise Fees Taxes Related to Margin	5,932		-		3,605		9,537	
97	Revenue Related State Taxes Related to Margin	2,738		-		1,664		4,402	
98	Margin Net of Tax	131,085	18,278	-	-	79,654	45,010	274,027	
	present revenues nongas	**$ 40,309,003**	**$ 5,568,288**	**$ 17,007,385**	**$ 719,262**	**$ 16,327,821**	**$ 1,284,681**	**$ 81,216,439**	
	Imbedded Tax Rates								
	Franchise Fees	4.2447%		4.2447%		4.2447%			
	State Gross Receipts	1.9591%		1.9591%		1.9591%			
	State Gross Transportation	(185)		550		1,212		1,576	
								$ 81,218,016	

EXHIBIT B

ATMOS ENERGY CORPORATION
WEST TEXAS SYSTEM STATEMENT OF INTENT GUD 10174
SUMMARY PROOF OF REVENUE - PROSPECTIVE RATES
TEST YEAR ENDING SEPTEMBER 30, 2011

Line No.	Description	West Texas ICL	West Texas OCL	Amarillo ICL	Amarillo OCL	Lubbock ICL	Lubbock OCL	Total
	(a)	(b)	(c)	(d)	(e)	(f)		(g)
	Residential							
1	Rate Characteristics:							
2	Customer Charge	$13.50	$13.50	$13.50	$13.50	$13.50	$13.50	
3								
4								
5	Consumption Charge ($/Ccf)							
6	All Consumption	$0.12614	$0.17055	$0.07550	$0.07550	$0.09175	$0.09175	
7								
8	Billing Units:							
9	Bills	1,478,085	151,820	783,776	28,396	746,485	54,205	3,242,768
10	Total Ccf	72,432,202	8,404,294	48,024,471	1,943,294	36,633,617	3,434,380	170,872,260
11		93.8%						
12	Proposed Revenue:							
13	Customer Charge	$ 19,954,153	$ 2,049,568	$ 10,580,978	$ 383,350	$ 10,077,549	$ 731,771	$ 43,777,368
14	Consumption Charge	9,136,392	1,433,352	3,625,997	146,725	3,360,972	315,089	$ 18,018,527
15	Base Revenue	$ 29,090,544	$ 3,482,920	$ 14,206,975	$ 530,075	$ 13,438,521	$ 1,046,860	$ 61,795,895
16	Revenue Related Franchise Fees Taxes Related to Margin	1,316,478	-	641,328	-	602,786	-	
17	Revenue Related State Taxes Related to Margin	607,614	-	296,002	-	278,213	-	
18	Margin Including Tax	31,014,636	3,482,920	15,144,305	530,075	14,319,520	1,046,860	65,538,316
19	**Commercial**							
20	Rate Characteristics:							
21	Customer Charge	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	
22								
23								
24	Consumption Charge ($/Ccf)							
25	All Consumption	$0.09317	$0.11330	$0.09794	$0.09794	$0.09045	$0.09045	
26								
27	Billing Units:							
28	Bills	122,916	20,342	69,398	2,183	67,524	3,657	286,020
29	Total Ccf	25,133,313	6,099,189	20,322,118	801,015	15,608,146	601,423	68,565,204
30								
31	Proposed Revenue:							
32	Customer Charge	$ 3,687,481	$ 610,255	$ 2,081,926	$ 65,493	$ 2,025,721	$ 109,723	$ 8,580,600
33	Consumption Charge	2,341,666	691,038	1,990,258	78,448	1,411,719	54,397	$ 6,567,526
34	Base Revenue	$ 6,029,147	$ 1,301,293	$ 4,072,185	$ 143,941	$ 3,437,440	$ 164,120	$ 15,148,126
35	Revenue Related Franchise Fees Taxes Related to Margin	272,846	-	185,156	-	155,259	-	613,261
36	Revenue Related State Taxes Related to Margin	125,931	-	85,458	-	71,659	-	283,048
37	Margin Including Tax	6,427,924	1,301,293	4,342,798	143,941	3,664,359	164,120	16,044,436

Industrial							
Rate Characteristics:							
Customer Charge	$275.00	$275.00	$275.00	$275.00	$275.00	$275.00	
Consumption Charge ($/Ccf)							
0-1000 Ccf	$0.05286	$0.06091	$0.11273	$0.11273	$0.07402	$0.07402	
Over 1000 Ccf	$0.05286	$0.06091	$0.11273	$0.11273	$0.07402	$0.07402	
Billing Units:							
Bills	917	1,382	271	12	586	48	3,216
Total Ccf	3,432,031	3,839,094	2,677,990	4,795	2,584,863	164,534	12,703,307
0-1000 Ccf	336,602	604,064	158,372	2,462	263,418	32,762	1,397,680
Over 1000 Ccf	3,095,429	3,235,030	2,519,618	2,333	2,321,445	131,773	11,305,627
Proposed Revenue:							
Customer Charge	$ 252,175	$ 380,050	$ 74,525	$ 3,300	$ 161,150	$ 13,200	$ 884,400
Consumption Charge							
0-1000 Ccf	181,417	233,839	301,891	541	191,341	12,179	$ 921,208
Over 1000 Ccf							
Base Revenue	$ 433,592	$ 613,889	$ 376,416	$ 3,841	$ 352,491	$ 25,379	$ 1,805,608
Revenue Related Franchise Fees Taxes Related to Margin	19,622	-	17,120	-	15,946	-	52,688
Revenue Related State Taxes Related to Margin	9,056	-	7,901	-	7,360	-	24,318
Margin Including Tax	462,271	613,889	401,437	3,841	375,796	25,379	1,882,613
Public Authority							
Rate Characteristics:							
Customer Charge	$75.00	$75.00	$75.00	$75.00	$75.00	$75.00	
Consumption Charge ($/Ccf)							
All Consumption	$0.08431	$0.10076	$0.10638	$0.10638	$0.12981	$0.12981	
Billing Units:							
Bills	16,284	1,172	2,401	173	1,566	169	21,765
Total Ccf	10,705,276	635,070	2,739,839	1,454,389	1,433,942	321,334	17,289,850
Proposed Revenue:							
Customer Charge	$ 1,221,328	$ 87,921	$ 180,046	$ 12,974	$ 117,421	$ 12,684	$ 1,632,375
Consumption Charge	902,609	63,987	291,455	154,713	186,136	41,712	$ 1,640,612
Base Revenue	$ 2,123,937	$ 151,908	$ 471,502	$ 167,688	$ 303,558	$ 54,396	$ 3,272,987
Revenue Related Franchise Fees Taxes Related to Margin	96,118	-	21,252	-	13,728	-	131,098
Revenue Related State Taxes Related to Margin	44,363	-	9,809	-	6,336	-	60,507
Margin Including Tax	2,264,417	151,908	502,563	167,688	323,621	54,396	3,464,592
State							
Rate Characteristics:							
Customer Charge	$75.00	$75.00	$75.00	$75.00	$75.00	$75.00	
Consumption Charge ($/Ccf)							
All Consumption	$0.10146	$0.13551	$ -	$ -	$0.11115	$0.11115	

87								
88	Billing Units:							
89	Bills	952	150	-	-	488	186	1,777
90	Total Ccf	588,133	51,825	-	-	468,367	357,774	1,466,099
91								
92	Proposed Revenue:							
93	Customer Charge	$ 71,411	$ 11,255	$ -	$ -	$ 36,637	$ 13,972	$ 133,275
94	Consumption Charge	59,673	7,023	-	-	52,057	39,765	$ 158,518
95	Base Revenue	$ 131,085	$ 18,278	$ -	$ -	$ 88,694	$ 53,737	$ 291,793
96	Revenue Related Franchise Fees Taxes Related to Margin	5,932	-	-	-	4,118	-	10,051
97	Revenue Related State Taxes Related to Margin	2,738	-	-	-	1,901	-	4,639
98	Margin Including Tax	139,755	18,278	-	-	94,713	53,737	306,482
	Proposed Margin Inclusive of Revenue Related Taxes	**$ 40,309,003**	**$ 5,568,288**	**$ 20,391,103**	**$ 845,544**	**$ 18,778,009**	**$ 1,344,492**	**$ 87,236,439**
	Current Margin Inclusive of Revenue Related Taxes	**$ 40,309,003**	**$ 5,568,288**	**$ 17,007,385**	**$ 719,262**	**$ 16,327,821**	**$ 1,284,681**	**$ 81,216,439**
		$ -	**$ -**	**$ 3,383,718**	**$ 126,282**	**$ 2,450,188**	**$ 59,812**	**$ 6,020,000**
	Imbedded Tax Rates							
	Local Gross Receipts	4.2447%		4.2447%		4.2447%		
	State Gross Receipts	1.9591%		1.9591%		1.9591%		
	State Gross Transportation	[redacted]						

ATMOS ENERGY CORPORATION
WEST TEXAS SYSTEM STATEMENT OF INTENT GUD 10174
RATE DESIGN - PROSPECTIVE

EXHIBIT B

NOTE (1): Each column includes both municipal and unincorporated billing determinates for the jurisdiction listed.

Line No.	Description		West Texas (1)	Amarillo (1)	Lubbock (1)	
	(a)		(b)	(c)	(d)	
	Residential					
1	Rate Characteristics:					
2	Customer Charge		$13.50	$13.50	$13.50	
3						
4						
5	Consumption Charge ($/Ccf)					
6	All Consumption		$0.13075	$0.07550	$0.09175	
7						
8	Billing Units:					
9	Bills		1,629,905	812,172	800,690	3,242,768
10	Total Ccf		80,836,497	49,967,765	40,067,998	170,872,260
11						
12	Proposed Revenue:					
13	Customer Charge		$ 22,003,720	$ 10,964,328	$ 10,809,320	$ 43,777,368
14	Consumption Charge		10,569,744	3,772,721	3,676,062	18,018,527
15	Base Revenue		$ 32,573,464	$ 14,737,050	$ 14,485,381	$ 61,795,895
16		Local Gross Receipts	1,316,478	641,328	602,786	
17		State Gross Receipts	607,614	296,002	278,213	
18		Margin Including Tax	34,497,556	15,674,379	15,366,380	65,538,316
19	**Commercial**					
20	Rate Characteristics:					
21	Customer Charge		$30.00	$30.00	$30.00	
22						
23						
24	Consumption Charge ($/Ccf)					
25	All Consumption		$0.09710	$0.09794	$0.09045	
26						
27	Billing Units:					
28	Bills		143,258	71,581	71,181	286,020
29	Total Ccf		31,232,502	21,123,133	16,209,569	68,565,204
30						
31	Proposed Revenue:					
32	Customer Charge		$ 4,297,736	$ 2,147,420	$ 2,135,444	$ 8,580,600
33	Consumption Charge		3,032,704	2,068,706	1,466,116	6,567,526
34	Base Revenue		$ 7,330,440	$ 4,216,126	$ 3,601,560	$ 15,148,126
35		Local Gross Receipts	272,846	185,156	155,259	
36		State Gross Receipts	125,931	85,458	71,659	
37		Margin Including Tax	7,729,217	4,486,739	3,828,479	16,044,436
38	**Industrial**					
39	Rate Characteristics:					
40	Customer Charge		$275.00	$275.00	$275.00	
41						
42	Consumption Charge ($/Ccf)					
43	0-1000 Ccf		$0.05711	$0.11273	$0.07402	
44	Over 1000 Ccf		$0.05711	$0.11273	$0.07402	
45						
46	Billing Units:					
47	Bills		2,299	283	634	3,216
48	Total Ccf		7,271,125	2,682,785	2,749,397	12,703,307
49	0-1000 Ccf		940,666	160,834	296,179	1,397,680
50	Over 1000 Ccf		6,330,458	2,521,951	2,453,218	11,305,627
51						
52	Proposed Revenue:					
53	Customer Charge		$ 632,225	$ 77,825	$ 174,350	$ 884,400
54	Consumption Charge					

Line						
55	0-1000 Ccf		415,257	302,431	203,520	921,208
56	Over 1000 Ccf					
57	Base Revenue		$ 1,047,482	$ 380,256	$ 377,870	$ 1,805,608
58		Local Gross Receipts	19,622	17,120	15,946	
59		State Gross Receipts	9,056	7,901	7,360	
60		Margin Including Tax	1,076,160	405,277	401,176	1,882,613
61	**Public Authority**					
62	Rate Characteristics:					
63	Customer Charge		$75.00	$75.00	$75.00	
64						
65						
66	Consumption Charge ($/Ccf)					
67	All Consumption		$0.08524	$0.10638	$0.12981	
68						
69	Billing Units:					
70	Bills		17,457	2,574	1,735	21,765
71	Total Ccf		11,340,346	4,194,228	1,755,276	17,289,850
72						
73	Proposed Revenue:					
74	Customer Charge		$ 1,309,249	$ 193,020	$ 130,106	$ 1,632,375
75	Consumption Charge		966,596	446,169	227,848	1,640,612
76	Base Revenue		$ 2,275,844	$ 639,189	$ 357,953	$ 3,272,987
77		Local Gross Receipts	96,118	21,252	13,728	
78		State Gross Receipts	44,363	9,809	6,336	
79		Margin Including Tax	2,416,325	670,250	378,017	3,464,592
80	**State**					
81	Rate Characteristics:					
82	Customer Charge		$75.00	$75.00	$75.00	
83						
84						
85	Consumption Charge ($/Ccf)					
86	All Consumption		$0.10422		$ 0.11115	
87						
88	Billing Units:					
89	Bills		1,102		675	1,777
90	Total Ccf		639,957		826,141	1,466,099
91						
92	Proposed Revenue:					
93	Customer Charge		$ 82,666	$ -	$ 50,609	$ 133,275
94	Consumption Charge		66,696	0	91,822	158,518
95	Base Revenue		$ 149,363	$ -	$ 142,430	$ 291,793
96		Local Gross Receipts	5,932	-	4,118	
97		State Gross Receipts	2,738	-	1,901	
98		Margin Including Tax	158,033	-	148,450	306,482
	Proposed Margin Inclusive of Revenue Related Taxes		**$ 45,877,291**	**$ 21,236,647**	**$ 20,122,502**	**$ 87,236,439**

Atmos Energy West Texas Division
Proposed Class Allocation - Settlement Offer GUD 10174

EXHIBIT B

	West Texas ICL	West Texas OCL	Amarillo ICL	Amarillo OCL	Lubbock ICL	Lubbock OCL	TOTAL	
CURRENT REVENUES*								
Residential	31,014,636	3,482,920	12,611,710	472,003	12,429,553	1,020,087	61,030,909	
Commercial	6,427,924	1,301,293	3,641,092	104,078	3,201,473	149,457	14,825,317	
Industrial	462,271	613,889	336,657	1,636	328,807	22,328	1,765,588	
Public Authority	2,264,417	151,908	417,926	141,545	283,065	47,799	3,306,661	
State Agency	139,755	18,278	-	-	84,923	45,010	287,965	
SUBTOTAL	40,309,003	5,568,288	17,007,385	719,262	16,327,821	1,284,681	81,216,439	
ICL / OCL SPLIT	87.86%	12.14%	95.94%	4.06%	92.71%	7.29%		
CURRENT DISTRIBUTION								Average Consumption
Residential	76.94%	62.55%	74.15%	65.62%	76.12%	79.40%	75.15%	52.69
Commercial	15.95%	23.37%	21.41%	14.47%	19.61%	11.63%	18.25%	239.72
Industrial	1.15%	11.02%	1.98%	0.23%	2.01%	1.74%	2.17%	3,950.03
Public Authority	5.62%	2.73%	2.46%	19.68%	1.73%	3.72%	4.07%	794.39
State Agency	0.35%	0.33%	0.00%	0.00%	0.52%	3.50%	0.35%	825.04
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
PROPOSED REVENUES*								
Residential	31,014,636	3,482,920	15,108,917	565,463	14,200,918	1,165,462	65,538,316	75.13%
Commercial	6,427,924	1,301,293	4,362,053	124,686	3,657,723	170,756	16,044,436	18.39%
Industrial	462,271	613,889	403,318	1,960	375,666	25,509	1,882,613	2.16%
Public Authority	2,264,417	151,908	500,679	169,572	323,406	54,611	3,464,592	3.97%
State Agency	139,755	18,278	-	-	97,025	51,425	306,482	0.35%
SUBTOTAL	40,309,003	5,568,288	20,374,966	861,680	18,654,738	1,467,763	87,236,439	100.00%
TOTAL CHANGE			3,367,581	142,419	2,326,917	183,083	6,020,000	

		0.0453	
REVENUE RELATED TAXES			
Local Gross Receipts	4.2447%	4.2447%	4.2447%
State Gross Receipts	1.9591%	1.9591%	1.9591%

Local Gross Receipts

ATMOS ENERGY CORPORATION
WEST TEXAS SYSTEM STATEMENT OF INTENT GUD 10174
PROPOSED RATES: RULE 7.210 COMPLIANCE

EXHIBIT B

The purpose of this schedule is to show that rates proposed for the unincorporated areas are within 115% of the average of all rates for similar services of all municipalities served by the same utility within the same county pursuant to Rule 7.210.

Line No.	Description	West Texas ICL	West Texas OCL	Amarillo ICL	Amarillo OCL	Lubbock ICL	Lubbock OCL
	(a)	(b)	(c)	(d)	(e)	(f)	
	Residential						
1	Rate Characteristics:						
2	Customer Charge	$13.50	$13.50	$13.50	$13.50	$13.50	$13.50
3							
4							
5	Consumption Charge ($/Ccf)						
6	All Consumption	$0.12614	$0.17055	$0.07550	$0.07550	$0.09175	$0.09175
7							
8	Billing Units:						
9	Bills	1,478,085	1,478,085	783,776	783,776	746,485	746,485
10	Total Ccf	72,432,202	72,432,202	48,024,471	48,024,471	36,633,617	36,633,617
11							
12	Proposed Revenue:						
13	Customer Charge	$ 19,954,153	$ 19,954,153	$ 10,580,978	$ 10,580,978	$ 10,077,549	$ 10,077,549
14	Consumption Charge	9,136,392	12,353,312	3,625,997	3,625,997	3,360,972	3,360,972
15	Base Revenue	$ 29,090,544	$ 32,307,465	$ 14,206,975	$ 14,206,975	$ 13,438,521	$ 13,438,521
16	Residential Percent Difference		11.06%		0.00%		0.00%
17							
18							
19	**Commercial**						
20	Rate Characteristics:						
21	Customer Charge	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
22							
23							
24	Consumption Charge ($/Ccf)						
25	All Consumption	$0.09317	$0.11330	$0.09794	$0.09794	$0.09045	$0.09045
26							

Billing Units:						
Bills	122,916	122,916	69,398	69,398	67,524	67,524
Total Ccf	25,133,313	25,133,313	20,322,118	20,322,118	15,608,146	15,608,146
Proposed Revenue:						
Customer Charge	$ 3,687,481	$ 3,687,481	$ 2,081,926	$ 2,081,926	$ 2,025,721	$ 2,025,721
Consumption Charge	2,341,666	2,847,604	1,990,258	1,990,258	1,411,719	1,411,719
Base Revenue	$ 6,029,147	$ 6,535,086	$ 4,072,185	$ 4,072,185	$ 3,437,440	$ 3,437,440
Commercial Percent Difference		8.39%		0.00%		0.00%

Industrial

Rate Characteristics:						
Customer Charge	$275.00	$275.00	$275.00	$275.00	$275.00	$275.00
Consumption Charge ($/Ccf)						
0-1000 Ccf	$0.05286	$0.06091	$0.11273	$0.11273	$0.07402	$0.07402
Over 1000 Ccf	$0.05286	$0.06091	$0.11273	$0.11273	$0.07402	$0.07402
Billing Units:						
Bills	917	917	271	271	586	586
Total Ccf	3,432,031	3,432,031	2,677,990	2,677,990	2,584,863	2,584,863
0-1000 Ccf	336,602	336,602	158,372	158,372	263,418	263,418
Over 1000 Ccf	3,095,429	3,095,429	2,519,618	2,519,618	2,321,445	2,321,445
Proposed Revenue:						
Customer Charge	$ 252,175	$ 252,175	$ 74,525	$ 74,525	$ 161,150	$ 161,150
Consumption Charge						
0-1000 Ccf	181,417	209,045	301,891	301,891	191,341	191,341
Over 1000 Ccf						
Base Revenue	$ 433,592	$ 461,220	$ 376,416	$ 376,416	$ 352,491	$ 352,491

Public Authority

Rate Characteristics:						
Customer Charge	$75.00	$75.00	$75.00	$75.00	$75.00	$75.00
Consumption Charge ($/Ccf)						

All Consumption	$0.08431	$0.10076	$0.10638	$0.10638	$0.12981	$0.12981
Billing Units:						
Bills	16,284	16,284	2,401	2,401	1,566	1,566
Total Ccf	10,705,276	10,705,276	2,739,839	2,739,839	1,433,942	1,433,942
Proposed Revenue:						
Customer Charge	$ 1,221,328	$ 1,221,328	$ 180,046	$ 180,046	$ 117,421	$ 117,421
Consumption Charge	902,609	1,078,615	291,455	291,455	186,136	186,136
Base Revenue	$ 2,123,937	$ 2,299,943	$ 471,502	$ 471,502	$ 303,558	$ 303,558
State						
Rate Characteristics:						
Customer Charge	$75.00	$75.00	$75.00	$75.00	$75.00	$75.00
Consumption Charge ($/Ccf)						
All Consumption	$0.10146	$0.13551	$ -	$ -	$0.11115	$0.11115
Billing Units:						
Bills	952	952	-	-	488	488
Total Ccf	588,133	588,133	-	-	468,367	468,367
Proposed Revenue:						
Customer Charge	$ 71,411	$ 71,411	$ -	$ -	$ 36,637	$ 36,637
Consumption Charge	59,673	79,700	0	0	52,057	52,057
Base Revenue	$ 131,085	$ 151,111	$ -	$ -	$ 88,694	$ 88,694
Proposed nongas revenues	**$ 37,808,306**	**$ 41,754,824**	**$ 19,127,077**	**$ 19,127,077**	**$ 17,620,703**	**$ 17,620,703**
Difference Between Environs and City Rates		**$ 3,946,518**		**$ -**		**$ -**
Percent Difference		**10.44%**		**0.00%**		**0.00%**

AVERAGE BILL COMPARISON
WTX, GUD 10174 SETTLEMENT

EXHIBIT B

	CURRENT					
	West Texas ICL	**West Texas OCL**	**Amarillo ICL**	**Amarillo OCL**	**Lubbock ICL**	**Lubbock OCL**
RESIDENTIAL						
Average Consumption	49.00	55.36	61.27	68.43	49.07	63.36
Customer Charge	7.50	13.50	8.21	13.50	7.86	13.50
Consumption Charge	0.27514	0.17055	0.12862	0.04562	0.17913	0.08395
Margin	20.98	22.94	16.09	16.62	16.65	18.82
Revenue Taxes on Margin						
Gas Cost (see below)	25.05	28.30	31.32	34.98	25.09	32.39
Average Bill	46.03	51.24	47.41	51.61	41.74	51.21
Percent Change From Current						
COMMERCIAL						
Average Consumption	204.48	299.83	292.84	366.91	231.15	164.44
Customer Charge	14.50	30.00	15.52	30.00	15.59	27.00
Consumption Charge	0.18484	0.11330	0.12617	0.04817	0.13767	0.08431
Margin	52.30	63.97	52.47	47.67	47.41	40.86
Revenue Taxes on Margin						
Gas Cost (see below)	104.53	153.28	149.70	187.57	118.17	84.06
Average Bill	156.83	217.25	202.17	235.25	165.58	124.93
Percent Change From Current						

NOTES:

GAS COST NOT GROSSED UP FOR REVENUE RELATED TAXES	0.4795
REVENUE RELATED TAXES - PER BOOK RATE (2)	6.20%
GAS COST WITH REVENUE TAX GROSS UP	0.5112

AVERAGE BILL COMPARISON
WTX, GUD 10174 SETTLEMENT

EXHIBIT B

	PROPOSED					
	West Texas ICL	**West Texas OCL**	**Amarillo ICL**	**Amarillo OCL**	**Lubbock ICL**	**Lubbock OCL**
RESIDENTIAL						
Average Consumption	49.00	55.36	61.27	68.43	49.07	63.36
Customer Charge	13.50	13.50	13.50	13.50	13.50	13.50
Consumption Charge	0.12614	0.17055	0.07550	0.07550	0.09175	0.09175
Margin	19.68	22.94	18.13	18.67	18.00	19.31
Revenue Taxes on Margin	1.30	-	1.20	-	1.19	-
Gas Cost (see below)	25.05	28.30	31.32	34.98	25.09	32.39
Average Bill	46.03	51.24	50.65	53.65	44.28	51.70
Percent Change From Current	0.0%	0.0%	6.8%	4.0%	6.1%	1.0%
COMMERCIAL						
Average Consumption	204.48	299.83	292.84	366.91	231.15	164.44
Customer Charge	30.00	30.00	30.00	30.00	30.00	30.00
Consumption Charge	0.09317	0.11330	0.09794	0.09794	0.09045	0.09045
Margin	49.05	63.97	58.68	65.93	50.91	44.87
Revenue Taxes on Margin	3.24	-	3.88	-	3.37	-
Gas Cost (see below)	104.53	153.28	149.70	187.57	118.17	84.06
Average Bill	156.83	217.25	212.26	253.51	172.44	128.94
Percent Change From Current	0.00%	0.00%	4.99%	7.76%	4.14%	3.21%

EXHIBIT C

Factors Required by Section 104.301 of the Texas Utilities Code

- The net invested capital amount of $354,663,775 shall be used as the baseline investment for use in calculating the first IRA adjustment following the issuance of a Final Order in this proceeding;

- The overall depreciation rate shall be calculated based on the WTX Direct depreciation rates approved by GUD 10041 and the SSU Depreciation rates approved by GUD 10170.

- A federal income tax factor of 35%;

- Ad Valorem Tax of $3,659,051 divided by the net invested capital of $354,663,775 for an Ad Valorem tax rate of 1.03%.

- The average use per month per customer class in order to determine the current and proposed bill information in future IRA filings is as follows: Residential at 52.69 Ccf, Commercial at 239.72 Ccf, Industrial at 3,950.03 Ccf, Public Authority at 794.39 Ccf, and State Institution at 825.04 Ccf; and

- The base rate revenue allocation factors to be used to calculate the cost of changes in investment to be recovered from the appropriate customer classes are as follows: Residential at 75.13%, Commercial at 18.39%, Industrial at 2.16%, Public Authority at 3.97%, and State Institution at 0.35%.

EXHIBIT D

ATMOS ENERGY CORPORATION
WEST TEXAS SYSTEM STATEMENT OF INTENT
PENSIONS AND RETIREE MEDICAL BENEFITS FOR COMMISSION APPROVAL
TEST YEAR ENDING SEPTEMBER 30, 2011

		Shared Services		West Texas System			
Line No.	Description	Pension Account Plan ("PAP")	Post-Retirement Medical Plan ("FAS 106")	Pension Account Plan ("PAP")	Post-Retirement Medical Plan ("FAS 106")	Supplemental Executive Retirement Plan ("SERP")	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Per Book Test Year Amounts	$ 4,395,408	$ 3,671,441	$ 1,460,203	$ 3,045,912	$ 161,626	
2							
3	Test Year - Actuarially Determined Benefit Costs (Ln 1)	$ 4,395,408	$ 3,671,441	$ 1,460,203	$ 3,045,912	$ 161,626	
4	Texas Division Allocation Factor	8.81%	8.81%	100.00%	100.00%	100.00%	
5	West Texas Allocation Factor	97.76%	97.76%	93.73%	93.73%	93.73%	
6	Test Year - Actuarially Determined Benefit Costs Allocated to WTX (Ln 3 x Ln 4 x Ln 5)	$ 378,561	$ 316,209	$ 1,368,648	$ 2,854,933	$ 151,492	
7	O&M and Capital Allocation Factor	100.00%	100.00%	100.00%	100.00%	100.00%	
8	Test Year - Actuarially Determined Benefit Costs To Approve (Ln 6 x Ln 7)	$ 378,561	$ 316,209	$ 1,368,648	$ 2,854,933	$ 151,492	
9							
10	**Summary of Costs to Approve:**						
11							
12	Total Pension Account Plan ("PAP")	$ 378,561		$ 1,368,648			$ 1,747,209
13	Total Post-Retirement Medical Plan ("FAS 106")		$ 316,209		$ 2,854,933		3,171,142
14	Total Supplemental Executive Retirement Plan ("SERP")	-	-			$ 151,492	151,492
15	Total (Ln 12 + Ln 13 + Ln 14)	$ 378,561	$ 316,209	$ 1,368,648	$ 2,854,933	$ 151,492	$ 5,069,843

Exhibit E

ATMOS WEST TEXAS CITIES (67)

Abernathy
Amherst
Anton
Big Spring
Bovina
Brownfield
Buffalo Springs
Canyon
Coahoma
Crosbyton
Dimmitt
Earth
Edmonson
Floydada
Forsan
Friona
Hale Center
Happy
Hart
Hereford
Idalou
Kress
Lake Tanglewood
Lamesa
Levelland
Littlefield
Lockney
Lorenzo
Los Ybanez
Meadow
Midland
Muleshoe
Nazareth
New Deal
New Home
Odessa
O'Donnell
Olton
Opdyke West
Palisades
Pampa
Panhandle
Petersburg
Plainview
Post
Quitaque
Ralls
Ransom Canyon
Ropesville
Sanford
Seagraves
Seminole
Shallowater
Silverton
Slaton
Smyer
Springlake
Stanton
Sudan
Tahoka
Timbercreek Canyon
Tulia
Turkey
Vega
Wellman
Wilson
Wolfforth

SERVICE LIST
Gas Utilities Docket No. 10174
Statement of Intent filed by Atmos Energy Corp.,
Mid-Tex Division to Change Gas Utility Rates in
the Unincorporated Areas Served by the
Atmos Energy Corporation, West Texas Division
Examiner: Gene Montes
Examiner: Cecile Hanna
Technical Examiner: Rose Ruiz

PARTIES	REPRESENTATIVE
Mr. Jeffrey Foley, Vice President **Atmos Energy Corp, West Texas Division** 5110 80th Street P.O. Box 1121 Lubbock, TX 79408-1121 806-798-4464 806-798-4494 fax	Ann M. Coffin Mark A. Santos Parsley Coffin Renner LLP 98 San Jacinto Blvd., Suite 1450 P.O. Box 13366 Austin, Texas 78711 512-879-0900 512-879-0912 (fax)
Railroad Commission of Texas John Pierce Griffin (hand deliver) Assistant Director of Appellate Law Railroad Commission of Texas 1701 N. Congress P.O. Box 12967 Austin, Texas 78711-2967 *512.475.3433* *512.463.6684 fax*	**Atmos Texas Municipalities** Alfred Herrera Herrera & Boyle, PLLC 816 Congress Avenue, Suite 1250 Austin, TX 78701 512-474-1492 512-474-2507 fax
	Steering Committee of Cities Served by Atmos West Texas Geoffrey M. Gay Georgia N. Crump Eileen McPhee LLOYD, GOSSELINK, ROCHELLE & TOWNSEND, P.C. P.O. Box 1725 Austin, Texas 78767 *512.322.5800* *512.472.0532 fax*
	State of Texas Larry Buch Susan M. Kelley Energy Rates Section Administrative Law Division Office of the Attorney General P.O. Box 12548 - Mail Code 018-12 Austin, Texas 78711-2548 *512.936.1660* *512.936.0674 fax*

cc: Mark Evarts

ORDINANCE NO. 523

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF FRITCH, TEXAS, ("CITY") APPROVING NEW RATES FOR ATMOS ENERGY CORPORATION, WEST TEXAS DIVISION ("ATMOS WEST TEXAS" OR THE "COMPANY") REGARDING THE COMPANY'S OCTOBER 18, 2013 STATEMENT OF INTENT TO INCREASE RATES; ORDERING THE FILING OF REVISED TARIFFS TO REFLECT RATES AND CHARGES APPLICABLE TO ALL CITIES WITHIN THE ATMOS WEST TEXAS SERVICE TERRITORY AS DETERMINED EITHER THROUGH REGULATORY AGREEMENT OR, IN THE EVENT THAT THE COMPANY'S OCTOBER 18, 2013 STATEMENT OF INTENT TO CHANGE RATES IS APPEALED, ENTRY OF A FINAL ORDER BY THE RAILROAD COMMISSION OF TEXAS; REPEALING CONFLICTING RESOLUTIONS OR ORDINANCES; DETERMINING THAT THIS ORDINANCE WAS PASSED IN ACCORDANCE WITH THE REQUIREMENTS OF THE TEXAS OPEN MEETINGS ACT; ADOPTING A SAVINGS CLAUSE; DECLARING AN EFFECTIVE DATE; AND REQUIRING DELIVERY OF THIS ORDIANCE TO THE COMPANY.

WHEREAS, the City of Fritch, Texas ("City") is a gas utility customer of Atmos Energy Corporation, West Texas Division ("Atmos West Texas" or the "Company"), and a regulatory authority with an interest in the rates and charges of Atmos West Texas; and

WHEREAS, Atmos West Texas filed a Statement of Intent to Increase Rates in its West Texas Division with the City and all other incorporated areas of the Atmos West Texas service area on or about October 18, 2013; and

WHEREAS, Atmos West Texas proposed to establish rates based on the division-wide cost of providing service to all areas within its West Texas Division, which includes the Amarillo, Lubbock and West Texas Cities rate jurisdictions; and

WHEREAS, the City, after reasonable notice, has reviewed the natural gas issues affecting rates charged in the Atmos West Texas service area; and

WHEREAS, the City has determined that the Company's proposed rates are reasonable and that any litigation relating to Atmos West Texas' proposal would cause the unnecessary incurrence of rate case expenses; and

WHEREAS, the City concludes that it is reasonable to establish rates for Atmos West Texas using a division-wide cost of service, which includes the Amarillo, Lubbock and West Texas Cities rate jurisdictions; and

WHEREAS, the City concludes that it is reasonable to establish rates and tariffs that are consistent with those proposed by the Company, those approved by other regulatory authorities with an interest in the rates and charges of Atmos West Texas or, those ultimately approved by the Railroad Commission of Texas in the event that the Company's October 18, 2013 Statement of Intent to Change Rates is appealed to that regulatory authority;

NOW, THEREFORE, BE IT ORDAINED BY THE CITY COUNCIL OF THE CITY OF FRITCH, TEXAS:

SECTION 1. THAT Atmos is hereby ordered to continue to charge and observe the level of rates currently in effect for Atmos West Texas until such time as rates and tariffs applicable to all cities within the Atmos West Texas service area are approved as filed, implemented through regulatory agreement or, in the event that the Company's October 18, 2013 Statement of Intent to Change Rates is appealed, the entry of a Final Order by the Railroad Commission of Texas.

SECTION 2. THAT upon establishing rates and tariffs applicable to all cities within the Atmos West Texas service area as filed, through regulatory agreement or ultimately, in the event that the Company's October 18, 2013 Statement of Intent to Change Rates is appealed, the entry of a Final Order by the Railroad Commission of Texas, Atmos West Texas shall file revised tariff sheets reflecting the resulting rates and charges with such rates and charges to take effect within 30 days of the date of filing with the City.

SECTION 3. THAT a copy of this Ordinance shall be sent to Atmos Energy Corporation, care of Jeffrey Foley, Vice President Rates and Regulatory Affairs, Atmos Energy Corporation, 5110 80th Street, P.O. Box 1121, Lubbock, Texas 79408-1121.

SECTION 4. THAT all Ordinances and Resolutions and parts of Ordinances and Resolutions in conflict herewith are hereby repealed.

SECTION 5. THAT if any provision, section, subsection, sentence, clause or phrase of this ordinance is for any reason held to be unconstitutional, void or invalid (or for any reason unenforceable), the validity of the remaining portions of this ordinance shall not be affected thereby, it being the intent of the City of Fritch in adopting this ordinance that no portion hereof or provision or regulation contained herein shall become inoperative or fail by any reason of any unconstitutionality or invalidity of any other portion, provision or regulation, and to this end, all provisions of this ordinance are declared to be severable.

SECTION 6. THAT the meeting at which this Ordinance was approved was in all things conducted in strict compliance with the Texas Open Meetings Act, Texas Government Code, Chapter 551.

PASSED, ADOPTED AND APPROVED at a regular meeting of the City Council of the City of Fritch, Texas, on this 17th of December, 2013.

Kevin Keener

Kevin Keener, Mayor

Cindy Cook

Cindy Cook. City Sec'y

REQUEST:

Provide any costs associated with any employment and/or termination contracts the LDC, its Parent, Multi-State Utility, or Affiliated Utility Service Company has or has had with management personnel since the last rate filing in Tennessee, and provide copies of such.

RESPONSE:

The Company has no employment or termination contracts with its Kentucky/Mid-States nor its Shared Services management employees.

Respondent: Jason Schneider

REQUEST:

Provide a detailed General Ledger for the latest 24 months for the LDC, its Parent, Multi-State Utility, and Affiliated Utility Service Company.

RESPONSE:

This response is voluminous and is provided in electronic format. Please see Attachment 1 through Attachment 6 for the requested information.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_1-08_Att1 - General Ledger 010 FY13.xlsx, 1,277 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, Staff_1-08_Att2 - General Ledger 010 FY14.xlsx, 1,210 Pages.

ATTACHMENT 3 - Atmos Energy Corporation, Staff_1-08_Att3 - General Ledger 091 FY13.xlsx, 323 Pages.

ATTACHMENT 4 - Atmos Energy Corporation, Staff_1-08_Att4 - General Ledger 091 FY14.xlsx, 301 Pages.

ATTACHMENT 5 - Atmos Energy Corporation, Staff_1-08_Att5 - General Ledger 093 FY13.xlsx, 432 Pages.

ATTACHMENT 6 - Atmos Energy Corporation, Staff_1-08_Att6 - General Ledger 093 FY14.xlsx, 428 Pages.

Respondent: Jason Schneider

REQUEST:

If the LDC, its Parent, Multi-State Utility, or Affiliated Utility Service Company, seeks to recover in its rates to the Tennessee ratepayers any separation payments made under any of the contracts, state the amount of any separation payments since the last rate filing in Tennessee.

RESPONSE:

Please see the Company's response to MFR No. 1-07.

Respondent: Jason Schneider